2026 INTEGRATED RESOURCE PLAN



Big Rivers
ELECTRIC CORPORATION

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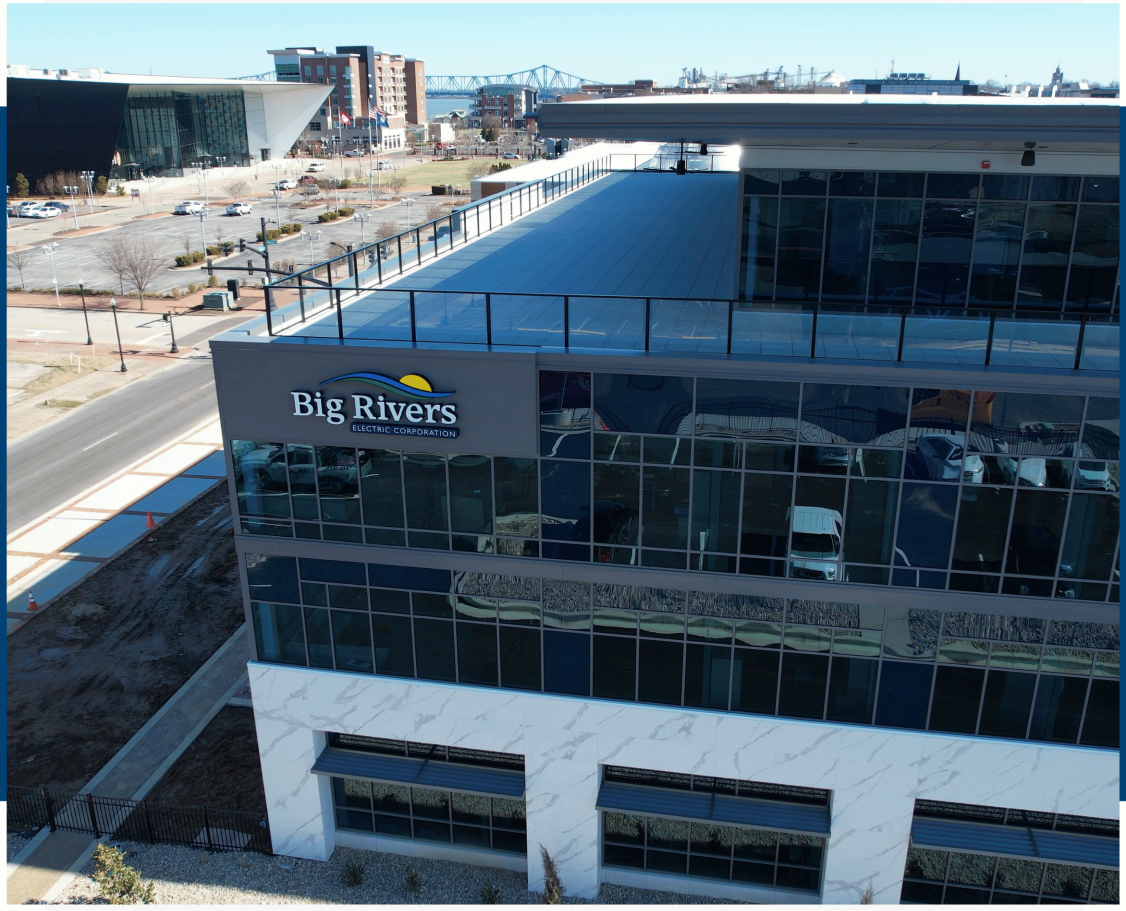
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Chapter 1

EXECUTIVE SUMMARY



1. EXECUTIVE SUMMARY

1.1 Overview

This Integrated Resource Plan ("IRP" or "2026 IRP") presents Big Rivers Electric Corporation's ("Big Rivers" or the "Company") plan for satisfying anticipated power requirements through 2050.[1] 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; technology costs associated with various resource plan outcomes; how these variables could change in different scenarios or views of the future; and how retirement of existing resources and the addition of demand response resources could change the generation portfolio. The Company intends that its 2026 IRP provide the Kentucky Public Service Commission (the "Commission" or "PSC") and all interested parties with detailed insight into the robust resource planning activities continuously undertaken at Big Rivers.

Big Rivers most recently filed an IRP with the Commission on September 29, 2023, in Case No. 2023-00310 (the "2023 IRP").[2] Commission Staff's report summarizing its review of Big Rivers' 2023 IRP was entered into the case record by Commission Order dated August 20, 2024. Commission Staff's report included a

[1] S*ee* Chapter 6, *Electric Integration Analysis*, Section 2.1 (*Planning Horizon*) for a discussion of the planning horizon used in the 2026 IRP.

[2] *In the Matter of: The 2023 Integrated Resource Plan of Big Rivers Electric Corporation*, Case No. 2023-00310.

number of recommendations, all of which are addressed in this 2026 IRP.[3] By Order dated September 25, 2024, the Commission closed Case No. 2023-00310 and established September 29, 2026, as the deadline for filing Big Rivers' 2026 IRP.

Pursuant to 807 KAR 5:058, Section 4(2), Table 1.1(a) identifies the individuals responsible for the preparation of this IRP, and available to respond to inquiries during the Commission's review of the IRP. Like the 2023 IRP, Big Rivers' Load Forecast (Appendix A) was prepared for the 2026 IRP by Clearspring Energy Advisors, LLC ("Clearspring"). The Demand Side Management ("DSM") analysis (Appendix B) for the 2026 IRP was prepared by GDS Associates, Inc. ("GDS"). Big Rivers also worked closely with Alliance for Cooperative Energy Services Power Marketing, LLC ("ACES"), in connection with this 2026 IRP.

Consistent with 807 KAR 5:058, Section 4(1), Appendix E contains a cross-reference table to the applicable regulatory requirements. Appendix G provides a list of acronyms used throughout this IRP. Supporting documents, figures, and tables are provided throughout this document and in the appendices, which form an integral part of this 2026 IRP.

[3] *See* Appendix G, Cross-Reference Table to Big Rivers Responses to Commission Staff Recommendation from the 2023 IRP.

Table 1.1(a)

2026 IRP Project Team

Company	*Name*	*Area of Expertise*
Big Rivers Electric Corporation	*Don Gulley*	*President and CEO*
	Micah Bushnell	*V.P. Energy Services*
	Manny Zeringue	*V.P. Generation*
	Derrick Miller	*V.P. Member Service & Economic Development*
	Ryan Wilhelmus	*Energy Services*
	Mason Milligan	*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	*Executive Director of Budgeting, Planning and Forecasting*
	Nicholas Castlen	*Finance*
	Tyson Kamuf	*General Counsel*
	Senthia Santana	*Associate Attorney*
ACES	*Erik Miller*	*Executive Director of Resource Planning*
	Kreig Voreis	*Director of Portfolio Strategy*
	Benjamin Heider	*Senior Resource Planning Analyst*
GDS Associates, Inc.	*Jacob Thomas*	*Principal*
	Jeffrey Huber	*Principal*
	Warren Hirons	*Consultant*
	Melissa Tucci	*Project Lead*
Clearspring Energy Advisors, LLC	*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 2026 IRP Plan Summary begins in this chapter and 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,[4] a summary of forecasts of the Company's energy and peak demand,[5] results of the demand-side management potential study,[6] discussion of the scenario, stochastic, and retirement analyses performed as part of this IRP,[4] and a summary of the Company's planned resource acquisitions and improvements.[7]

1.2 Big Rivers, Its Members, Service Territory, Current Facilities and Planning Objectives[8]

1.2.1 Big Rivers and the Member-Owners

Big Rivers is a generation and transmission cooperative incorporated June 14, 1961, with headquarters in Owensboro, Kentucky. Big Rivers owns, operates,

[4] *See* Chapter 6, *Electric Integration Analysis*, for a description of the key assumptions and analytical methods used in this IRP.

[5] *See* Chapter 3, *Load Forecast,* and Appendix A, Long-Term Load Forecast Report for a description of the forecasting methodology and resulting energy and peak demand forecasts.

[6] *See* Chapter 4, *Demand-Side Management* and Appendix B, Demand-Side Management Potential Study for additional information regarding the demand-side management potential study and its results.

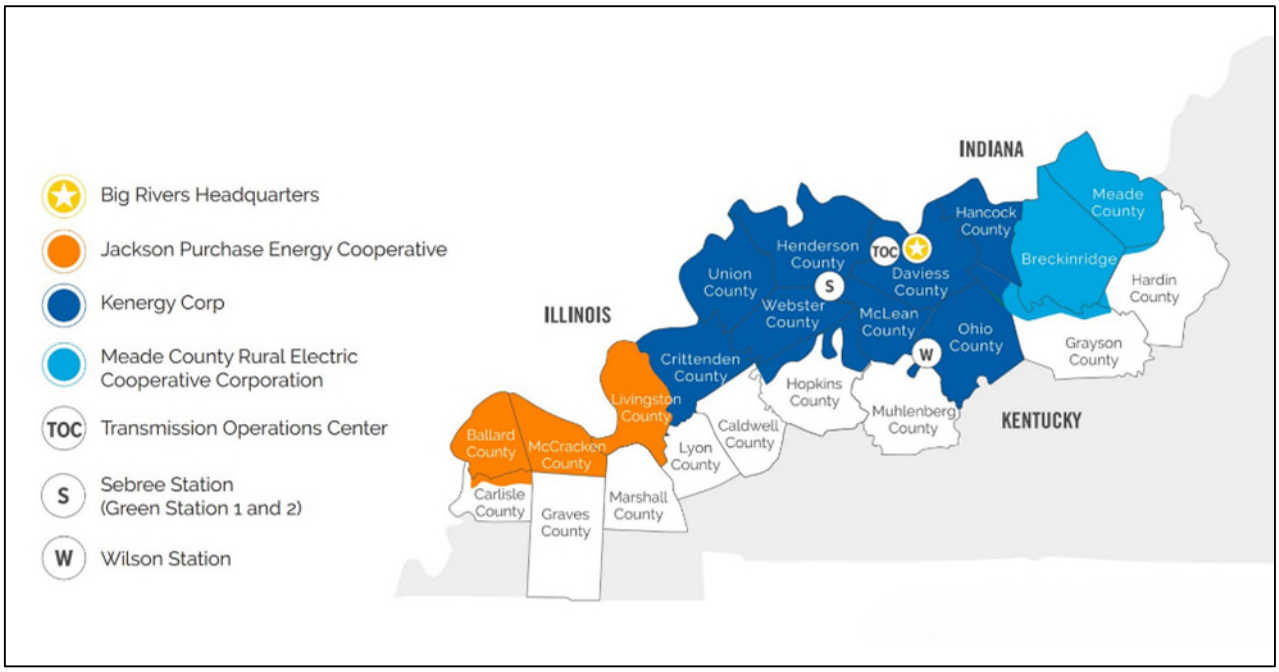
[7] *See* Chapter 9, *Action Plan,* for a summary of the actions identified by Big Rivers in this IRP.

[8] Responsive to 807 KAR 5:058, Section 5(1).

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, 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 1.2.1(a).

Figure 1.2.1(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.[9] Wholesale power contracts for Big Rivers' Member-Owners and Commission–approved wholesale power agreements are likewise on file with the Commission and available through the Commission's online library.

[9] *Big Rivers Electric Corp. Gen. Tariff* , Ky. P.S.C. No. 27, available on file with the Ky. Pub. Serv. Comm'n at www.psc.ky.gov/tariffs/Electric/Big%20Rivers%20Electric%20Corporation/General%20Tariff.pdf; also available at https://www.bigrivers.com/regulatory-affairs-and-compliance.html *and at* https://psc.ky.gov/tariffs/electric/big%20rivers%20electric%20corporation/general%20tariff.pdf

1.2.2 RTO Membership / Bilateral Contracts

With Commission approval, Big Rivers became a fully-integrated member of Midcontinent Independent System Operator ("MISO") on December 1, 2010.[10] The Company participates in the Regional Transmission Organization's ("RTO") day-ahead and real-time energy and capacity markets. Big Rivers provides transmission and ancillary services under the MISO Tariff [11] and will serve load in the Southwest Power Pool[12] until June 2027. Detailed discussion of the Company's MISO participation is contained in Section 2.4 (Significant Changes - MISO) and Chapter 8, MISO and Resource Adequacy Planning Considerations.

While much of Big Rivers' generating capacity is dedicated to the Company's native load, Big Rivers has optimized on its diverse resource portfolio through its participation in MISO markets and bilateral power sales contracts. For instance, Big Rivers has successfully received Commission approval to execute bilateral power contracts with entities in the State of Nebraska, with the last contract expiring in June 2027; with Owensboro Municipal Utilities (expiring March 2027); and with the Kentucky Municipal Energy Agency.[13] Detailed discussion of the

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[10] *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).

[11] MISO Tariff, available at https://www.misoenergy.org/legal/rules-manuals-and-agreements/tariff/.

[12] Southwest Pool Tariff, available at https://sppviewer.etariff.biz/tariff/.

[13] The contract between Big Rivers and KYMEA terminates May 31, 2029, subject to KYMEA's right to exercise a 10-year extension option. For IRP purposes, analysis assumed the KYMEA contract is extended until 2039 at 50 MWs, See Chapter 6, E*lectric Integration Analysis*.

Company's non-native load obligations is contained in Chapter 4, Demand-Side Management and Appendix A, Long-Term Load Forecast Report.

1.2.3 Current Generation Facilities[14]

Big Rivers' present total power capacity is 1,209 MW, derived from a variety of generation resources. Big Rivers owns and operates the Robert D. Green Plant ("Green") (454 MW) and the D. B. Wilson Plant ("Wilson") (417 MW), totaling 871 net MW of generating capacity. As discussed in the following subsections, Big Rivers also utilizes 178 MW of contracted hydroelectric capacity from the Southeastern Power Administration ("SEPA"), and solar capacity from Unbridled Solar of 160 MW.

Because it is the most economic unit, Wilson runs the most among Big Rivers' generating units. 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 Flue Gas Desulfurization ("FGD") Wheelabrator Air Pollution Control. A total of 112 skilled employees is involved in the operation of Wilson, 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 is located in Sebree, Kentucky, and includes the Green Plant and Reid Plant. The Green Plant includes two boiler/turbines (231

[14] Responsive to 807 KAR 5:058, Section 5(1).

MW and 223 MW), each converted from coal-fired to natural gas-fired in 2022. The Reid Plant includes the 65 MW Robert Reid Combustion Turbine (the "Reid CT"), which remains unavailable since experiencing a catastrophic forced outage in 2024.

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. The arrays provide retail members, first responders, and students with 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. See Figures 1.2.3(a) and 1.2.3(b) for an overview of Big Rivers' Green and Wilson generation facilities.

Figure 1.2.3(a)

Generation Facility Overview – Green Station

GREEN STATION

Green Station consists of two units, Green Unit 1 and Green Unit 2, with a combined net generating capacity of 454 MW.

- 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.



Figure 1.2.3(b)

Generation Facility Overview – Wilson Station

WILSON STATION

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

- Foster Wheeler boiler and Westinghouse turbine generator, commercialized in 1986.
- The upgraded flue gas desulphurization (FGD) system is a Wheelabrator Air Pollution Control open tower, wet, double, dual flow tray design.
- The selective catalytic reduction (SCR) system is a Babcock Borsig delta wing design that uses a catalyst and ammonia reagent to remove 90% of the unit's nitrous oxide (NOx) emissions.



Big Rivers places emphasis on efficiency, so the Company continues to make strides in generation efficiency improvements to maximize asset value. Big Rivers continues to offer its generating resources into the MISO market at the lowest generation levels consistent with reliable operations, minimizing market losses while maintaining unit availability-demand periods

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 1.2.3(c) and Table 1.2.3(a), which reflect actual heat rate performance based on MISO dispatch.

Figure 1.2.3(c)

System Net Actual Heat Rate



Table 1.2.3(a)

System Net Actual Heat Rate

Year	BTU/kWH
2012	[redacted]
2013	
2014	
2015	
2016	
2017	
2018	
2019	
2020	
2021	
2022	
2023	
2024	
2025	

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

- **Human-Machine Interfaces (HMI):** Big Rivers has implemented High-Performance HMI technology and advanced Distributed Control Systems to provide operators with clear, actionable information that improves situational awareness and decision-making. Through real-time monitoring of process conditions, equipment health, and key performance indicators, control room staff can proactively manage plant operations, quickly address abnormalities, and optimize performance while maintaining safe and reliable generation.
- **Operations Training Simulators:** Operator qualification programs continue to utilize high-fidelity training simulators at Wilson and Green

Stations. These simulators provide realistic operating scenarios including unit startups, shutdowns, equipment failures, abnormal operating conditions, and emergency response events. Ongoing training helps ensure operators maintain proficiency while supporting safe and reliable unit operation.

- **Controllable Losses:** Engineering and Operations personnel continuously monitor key operating parameters that influence generating unit performance, including:
    - Heat rate
    - Auxiliary power consumption
    - Boiler efficiency
    - Condenser performance
    - Excess oxygen
    - Air heater leakage
    - Steam temperatures
    - Pulverizer performance
    - Environmental control system performance.

  Performance data is reviewed routinely to identify optimization opportunities while maintaining reliability and environmental compliance.

- **Maintenance:** The Operations organization works closely with the Maintenance and Engineering organizations to improve equipment reliability and reduce forced outages. Preventive, predictive, and condition-based maintenance programs continue to expand through the use of vibration

monitoring, infrared inspections, lubrication analysis, equipment health monitoring, and root cause failure analysis.

Routine maintenance activities include:

- Condenser cleaning
- Air heater cleaning
- Steam trap inspections
- Valve leak reduction
- Air and gas leakage repairs
- Pulverizer inspections
- Instrument calibration
- Rotating equipment inspections.

- **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:** Maintaining efficient combustion remains an important component of generation operations. Big Rivers routinely performs coal fineness testing, coal pipe balancing, pulverizer inspections, burner optimization, and combustion tuning to improve boiler efficiency, reduce emissions, and minimize unburned carbon losses.

Table 1.2.3(b) presents the five-year averages (2021-2025) of key performance indicators of Big Rivers' generating units.

Table 1.2.3(b)

Key Performance Indicators per IEEE[15] Standards

Unit	NAG[16]	Average Net Generation (MWHrs)	Net Heat Rate (BTU/kWH)	Gross Capacity Factor (%)	Gross Output Factor (%)	Equivalent Availability Factor (%)	Equivalent Forced Outage Rate (%)
Green 1	2,589,696	517,939		26.98	68.73	84.74	14.33
Green 2	2,089,905	417,981		22.63	68.89	87.80	7.43
Wilson 1	13,179,744	2,635,949		72.49	88.49	77.90	13.72
System	17,859,345	3,571,869		47.55	82.07	83.48	12.59

Table 1.2.3(c) is a summary of the operating characteristics of existing Big Rivers resources.

[15] The Institute of Electrical and Electronics Engineers (IEEE) is a professional association that develops technical standards and guidance for the electric utility industry.

[16] "NAG" means Net Actual Generation delivered to the grid over the 5-year period 2021-2025.

Table 1.2.3(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	Secondary		
R.D. Green	1	Webster	Existing	December-1979	Steam Turbine	231	231	Gas**			TBD *
R.D. Green	2	Webster	Existing	January-1981	Steam Turbine	223	223	Gas**			TBD *
R.A. Reid	2	Webster	Existing	March-1978	Combustion Turbine	65	65	Gas			2027/2028
D.B. Wilson	1	Ohio	Existing	November-1986	Steam Turbine	417	417	Coal	Oil	60 days	TBD *

** Beyond the study horizon: base case modeling for the 2026 IRP showed both Green units and Wilson should remain in service through 2050.*

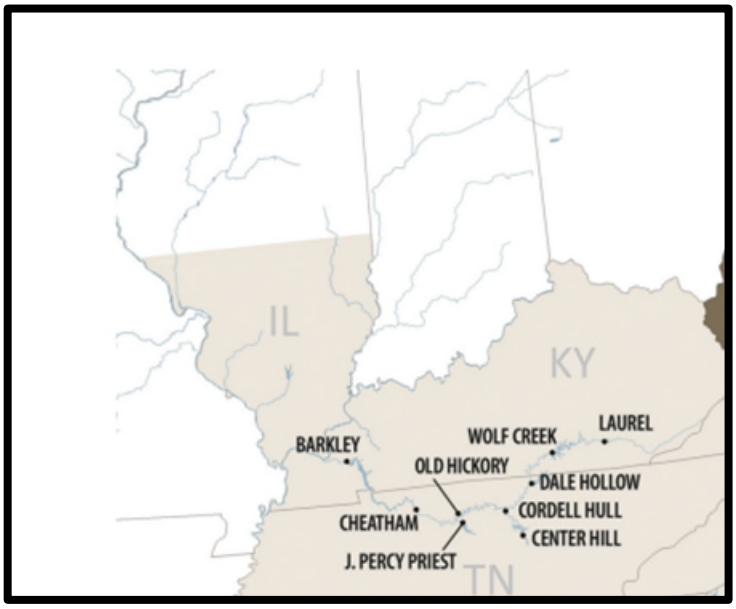
**Green Units were converted to natural gas in 2022

1.2.4 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 1.2.4(a) is a map of the Cumberland System projects.

Figure 1.2.4(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 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.

1.2.5 Solar Resource

In addition to the capacity resources above, Big Rivers has a 20-year agreement to purchase all the capacity, energy, ancillary services and environmental attributes of the 160 MW Unbridled Solar Facility located in Henderson and Webster Counties, Kentucky.[17] This facility started commercial operation in February of 2025.

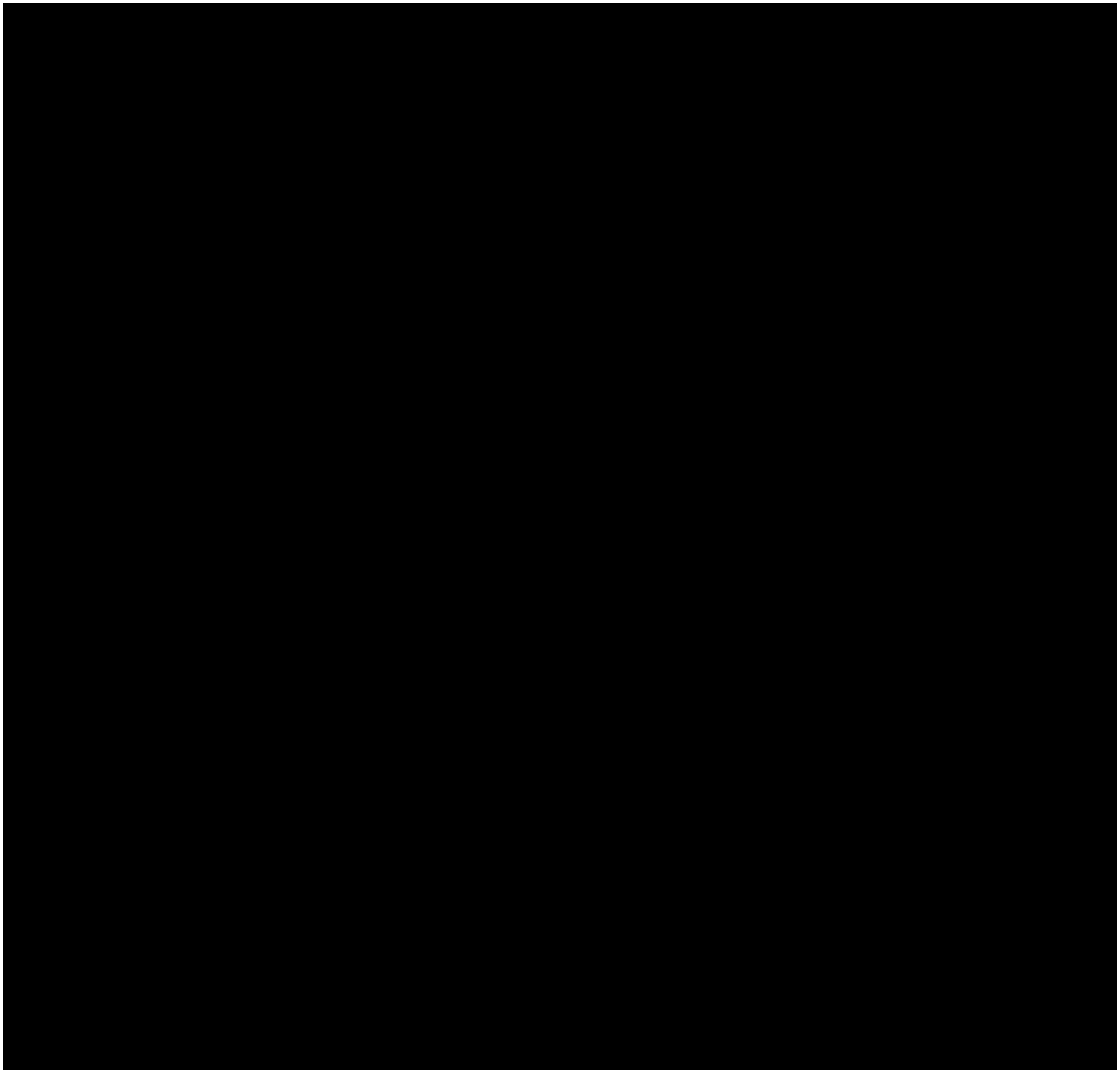
1.2.6 Current Transmission System

Big Rivers owns, operates and maintains 1,353 miles of conductor and twenty-nine (29) 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 map of the transmission system is provided in Figure 1.2.6(a), and a more detailed map is provided in Appendix C.

[17] *See 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) (amending the original contract approved in Case No. 2020-00183 by Order dated Sept. 28, 2020).

Figure 1.2.6(a)

Transmission System Map



The Company has completed various project upgrades that are expected to improve reliability for its Members. These upgrades include the use of steel and ductile iron poles for all new construction projects and pole replacements, adding

remote control switches at strategic locations to improve switching response, upgrading many relays to new microprocessor relays, the replacement of aging oil circuit breakers, and the installation of Optical Ground Wire ("OPGW") for fiber-optic communication.

Independent power producers have connected 760 MW of solar generation to the Big Rivers transmission system. This includes 200 MW connected to the Meade County substation in 2025, 400 MW connected to the Reid Extra High Voltage ("EHV") Substation in 2025/2026, and 160 MW connected to the Reid Substation in 2025.

In 2025, Big Rivers completed the transition to the new Transmission Operations Center in Owensboro and received certification by Southeast Electric Reliability Corporation ("SERC"). This modern facility is more resilient, with a hardened tornado-resistant transmission control center and indoor space to protect transmission repair and maintenance equipment from the elements. The energy management system was upgraded as part of this project.

In December of 2024, the MISO Board of Directors approved the second phase of its Long-Range Transmission Plan ("LRTP"). MISO's LRTP is an integral part of the MISO Transmission Expansion Plan ("MTEP"). The LRTP focuses on regional system solutions to enhance the reliability and efficiency of the grid, ensuring it is positioned to meet future resource developments. Included within this second phase of the LRTP is a 30-mile 345 kiloVolt ("kV") transmission line that will

connect Big Rivers' Reid EHV Substation to CenterPoint Energy facilities in southern Indiana. Once complete in 2032 or earlier, this project will strengthen reliability and resiliency by reinforcing the transmission backbone in Kentucky. Discussion of Big Rivers' transmission planning is provided in Chapter 7, Transmission Planning.

1.2.7 Big Rivers' Member Load and Load Growth[18]

Big Rivers' 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-native load is defined as planned long-term load obligations that create value for Big Rivers' Members.[19] Chapter 4 and Appendix A discuss the procedures used to develop the forecast. [20]

Big Rivers categorizes native energy and peak demand into two classes: rural system and direct serve. The rural system is comprised of all retail residential, commercial, and industrial consumers served by Big Rivers' three Members, excluding retail consumers directly served from the transmission system under Big Rivers' Large Industrial Customer ("LIC") tariff or special contracts, referred to as the Direct Serve class. At the time the load forecast was developed there were sixteen (16) Direct Serve consumers. The Direct Serve class contributed 42.7% of

[18] Responsive to 807 KAR 5:058, Section 5(1).

[19] Native and non-native terminology is used interchangeably with member and non-member throughout the report.

[20] Unless otherwise noted, references to total system energy and peak demand requirements in the 2025 Load Forecast pertain to Big Rivers' Members' native system and Big Rivers' Non-Member load. *See* Appendix A, Long-Term Load Forecast Report.

Big Rivers' Member kilowatt-hour ("kWh") Sales in 2024 and is projected to contribute 42.7% of Big Rivers' Member kWh Sales in 2044.

A breakdown of actual native energy sales for 2024 and projected sales for 2044 by class is presented in Figures 1.2.7(a) and 1.2.7(b) respectively.

Figure 1.2.7(a)

Class Energy kWH Sales Proportions for Native System 2024

(Not Including Transmission Losses)

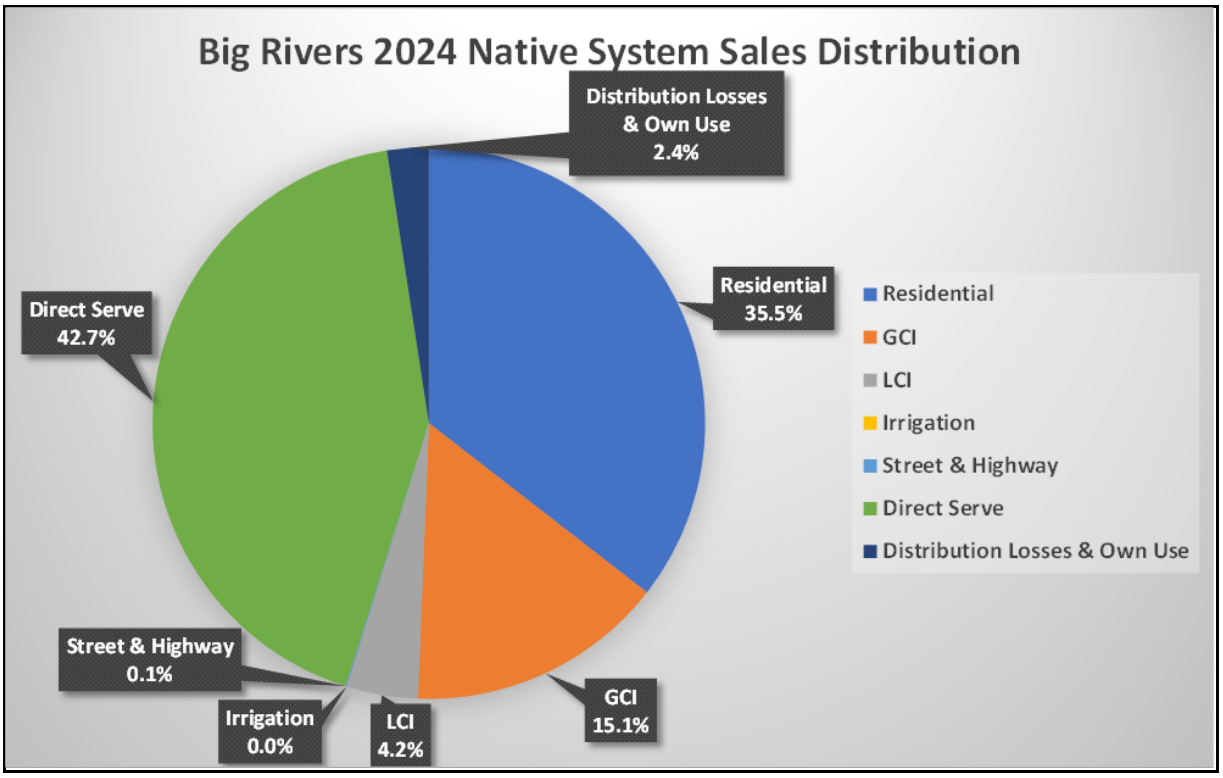
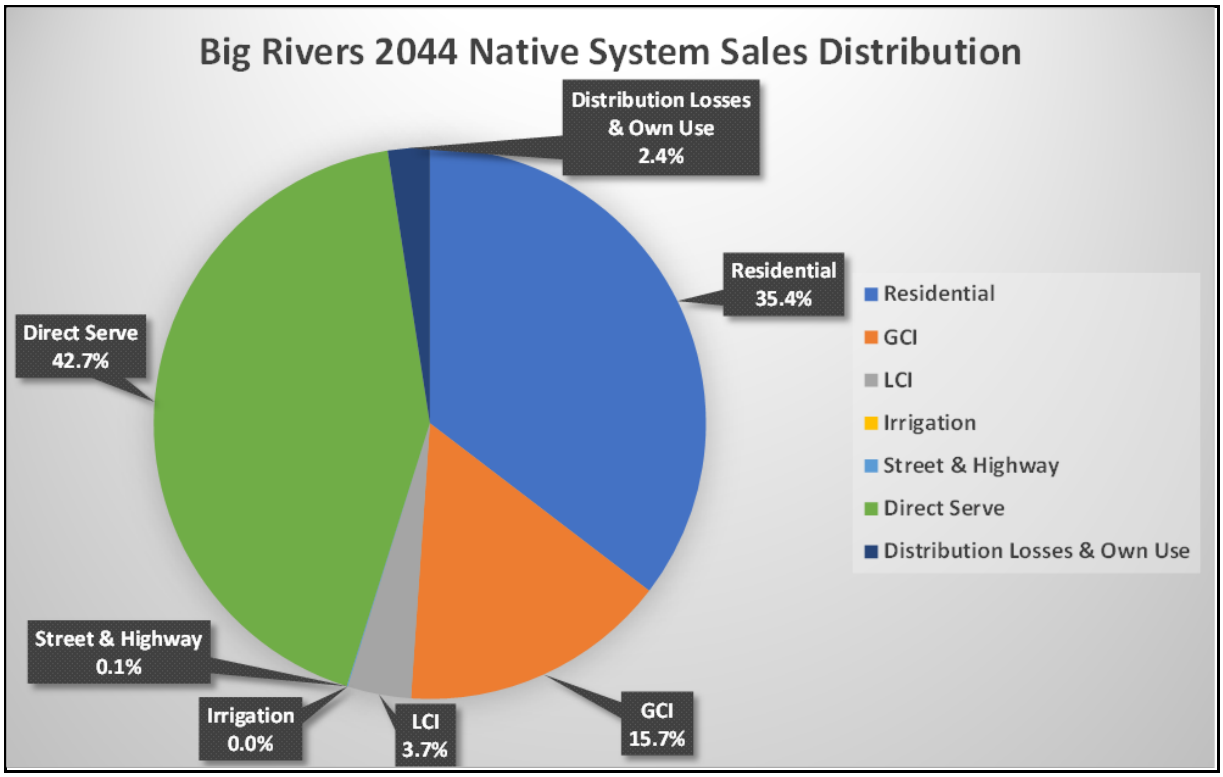


Figure 1.2.7(b)

Class Energy kWH Sales Proportions for Native System 2044

(Not Including Transmission Losses)



As mentioned above, Big Rivers' total system energy and peak demand requirements are comprised of its native system load and non-native load. Total requirements include transmission losses, which are included in later tables and graphs but not in Figures 1.2.7(a) and 1.2.7(b). Native system energy and peak demand requirements are projected to reach 4,657 GWh and 833 MW, respectively, by 2044. Annual native load coincident peak ("CP") projections are presented in Table 1.2.7(a), and Big Rivers' total native system energy summary is presented in Table 1.2.7(b). Refer to Sections 3.3 (Capacity) and 3.4 (Energy) of Appendix A. for details on additional Non-Member sales.

Table 1.2.7(a)

2026 Big Rivers CP Load Forecast (kW)

(Includes Transmission Losses)

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
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	598,264	598,264	88,521	248	16,102	703,135
2023	490,432	349,748	490,432	225,419	99	17,155	733,105
2024	486,295	486,068	486,295	262,165	104	18,378	766,942
2025	**455,173**	**452,727**	**455,173**	**267,211**	**143**	**18,061**	**740,587**
2026	**460,529**	**457,380**	**460,529**	**273,399**	**143**	**18,350**	**752,420**
2027	**463,671**	**459,623**	**463,671**	**276,079**	**143**	**18,495**	**758,388**
2028	**466,205**	**461,086**	**466,205**	**276,577**	**143**	**18,571**	**761,496**
2029	**468,897**	**462,639**	**468,897**	**277,371**	**143**	**18,658**	**765,068**
2030	**470,437**	**463,099**	**470,437**	**278,240**	**143**	**18,718**	**767,538**
2031	**473,604**	**465,148**	**473,604**	**279,118**	**143**	**18,819**	**771,684**
2032	**477,854**	**468,247**	**477,854**	**279,921**	**143**	**18,946**	**776,863**
2033	**482,140**	**470,935**	**482,140**	**280,842**	**143**	**19,076**	**782,200**
2034	**486,736**	**473,856**	**486,736**	**281,648**	**143**	**19,211**	**787,737**
2035	**490,833**	**476,400**	**490,833**	**282,536**	**143**	**19,335**	**792,847**
2036	**494,175**	**478,332**	**494,175**	**283,502**	**143**	**19,443**	**797,262**
2037	**498,687**	**481,462**	**498,687**	**284,392**	**143**	**19,578**	**802,800**
2038	**502,587**	**484,119**	**502,587**	**285,362**	**143**	**19,700**	**807,791**
2039	**506,430**	**486,840**	**506,430**	**286,321**	**143**	**19,820**	**812,713**
2040	**509,638**	**489,065**	**509,638**	**287,290**	**143**	**19,924**	**816,994**
2041	**513,011**	**491,601**	**513,011**	**288,352**	**143**	**20,035**	**821,541**
2042	**516,244**	**494,154**	**516,244**	**289,407**	**143**	**20,142**	**825,936**
2043	**518,799**	**496,118**	**518,799**	**290,465**	**143**	**20,233**	**829,639**
2044	**521,068**	**497,854**	**521,068**	**291,604**	**143**	**20,318**	**833,133**
Average Annual Growth Rates							
Previous 10 Years	**0.11%**	**-2.34%**	**-2.34%**	**7.76%**	**-**	**5.98%**	**0.22%**
Previous 5 Years	**0.25%**	**-0.20%**	**-0.19%**	**17.32%**	**-**	**2.82%**	**4.18%**
Next 5 Years	**-0.73%**	**-0.98%**	**-0.73%**	**1.13%**	**6.59%**	**0.30%**	**-0.05%**
Next 10 Years	**0.01%**	**-0.25%**	**0.01%**	**0.72%**	**3.24%**	**0.44%**	**0.27%**
Next 20 Years	**0.35%**	**0.12%**	**0.35%**	**0.53%**	**1.61%**	**0.50%**	**0.41%**

Table 1.2.7(b)

Big Rivers Total Native System Energy Summary (MWh)

(Includes Transmission Losses)

Big Rivers Total Native System Energy Summary (MWh)					
Year	Total Rural Requirements	Direct Serve	Aux Load	Transmission Losses	Total System Energy Requirements
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	811,577	6,184	72,325	3,159,672
2023	2,097,660	1,167,083	833	78,103	3,343,678
2024	2,179,785	1,623,201	935	93,173	3,897,094
2025	2,238,259	1,785,062	935	100,594	4,124,850
2026	2,267,529	1,842,767	935	102,768	4,213,999
2027	2,285,503	1,861,031	935	103,674	4,251,143
2028	2,301,046	1,863,066	935	104,114	4,269,159
2029	2,317,481	1,867,091	935	104,625	4,290,131
2030	2,328,667	1,871,556	935	105,016	4,306,175
2031	2,347,896	1,876,179	935	105,613	4,330,623
2032	2,372,775	1,880,236	935	106,336	4,360,282
2033	2,395,795	1,884,854	935	107,027	4,388,610
2034	2,420,143	1,888,897	935	107,736	4,417,711
2035	2,442,083	1,893,375	935	108,397	4,444,789
2036	2,460,336	1,898,249	935	108,975	4,468,495
2037	2,484,286	1,902,702	935	109,685	4,497,607
2038	2,505,191	1,907,552	935	110,329	4,524,006
2039	2,525,724	1,912,320	935	110,961	4,549,940
2040	2,542,976	1,917,144	935	111,513	4,572,567
2041	2,561,009	1,922,446	935	112,096	4,596,485
2042	2,578,209	1,927,690	935	112,657	4,619,491
2043	2,591,846	1,932,939	935	113,129	4,638,848
2044	2,603,815	1,938,625	935	113,571	4,656,945
Average Annual Growth Rates					
Previous 10 Years	-1.02%	5.32%	-	5.52%	1.27%
Previous 5 Years	-0.73%	11.40%	-26.76%	2.38%	3.42%
Next 5 Years	1.23%	2.84%	0.00%	2.35%	1.94%
Next 10 Years	1.05%	1.53%	0.00%	1.46%	1.26%
Next 20 Years	0.89%	0.89%	0.00%	0.99%	0.89%

Native system energy and peak demand requirements are projected to increase at average compound rates of 0.89 % and 0.41%, respectively, per year from 2025 through 2044. 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 native energy sales. Native peak requirements are projected to increase from 741 MW in 2025 to 833 MW (including transmission losses) by the summer of 2044.

1.2.8 Economic Development

Additional large industrial load growth is anticipated in the future. While the number of requests for information ("RFIs") from prospective economic development projects has declined, the projects currently under consideration remain strong, credible economic development opportunities with significant potential impact. *See* Table 1.2.8(a) below for details on the number of requests for information in the Big Rivers service territory since 2021.

Table 1.2.8(a)

RFIs in the Big Rivers' Service Territory (2021-2025)

	2021	2022	2023	2024	2025	YTD 2026
RFI's	73	71	48	39	22	14
Capital Investment	$29.1 B	$38.5B	$45.1B	$16.5B	$9.8B	$15.4B
Jobs	26,123	41,697	27,705	6,409	18,034	5,495
MW's	4,657	5,214	6,110	2,913	798	2,647
Data Center Activity						
RFI's				8	18	13
MW's				1,100	4,684	4,770

This approach requires prospective large-load customers to pay the costs associated with system impact studies and preliminary engineering needed to estimate potential construction costs and timelines. Prospects that choose to advance a project understand that Big Rivers will evaluate any service plan under the following principles:

- Protect existing members from undue cost or reliability risk
- Provide significant value to the broader membership
- Establish a durable, long-term power supply solution.

Together, these principles enable Big Rivers to financially isolate these prospective large-load projects from existing members and avoid incorporating those loads into standard power planning unless a defined service arrangement is in place. These large-load prospects are expected to assume the power supply risks and related financial obligations associated with market purchases or long-term supply options, including generation resources, curtailment provisions and

power purchase agreements. The Commission-approved special contracts among Big Rivers, Block Mining, Inc. (retail service by JPEC),[21] and TeraWulf (retail service by Kenergy)[22] demonstrate the application of these principles in practice.

In addition to traditional economic development opportunities, interest from data center and artificial intelligence ("AI") developers has grown significantly. Since the beginning of 2025, Big Rivers has received thirty-one (31) RFI's from data center developers, nearly equal to the number received from all other industries combined. These projects require substantial electric capacity and advanced infrastructure, prompting companies to search nationwide for locations that can meet their operational needs.

Although interest from data center developers has increased dramatically, only five projects have advanced beyond the initial stages. One project progressed to an executed service agreement and recently received Commission approval; [23]

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[21] 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,* Ky. P.S.C. Case No. 2021-00282; *Agreement for Electric Service (the "New Commerce Park Site Agreement") among Big Rivers, Jackson Purchase Energy Corporation and Block Mining, Inc.,* Ky. P.S.C. Tariff Filing No. TFS2026-00037; and *Agreement for Electric Service (the "Shell Site Agreement") among Big Rivers, Jackson Purchase Energy Corporation and Block Mining, Inc.,* Ky. P.S.C. Tariff Filing No. TFS2026-00338.

[22] *See Electronic Tariff Filing of Big Rivers Electric Corporation of a Retail Electric Service Agreement with Justified DataPower LLC a Subsidiary of TeraWulf Inc.,* Ky. P.S.C. Case No. 2026-00115.

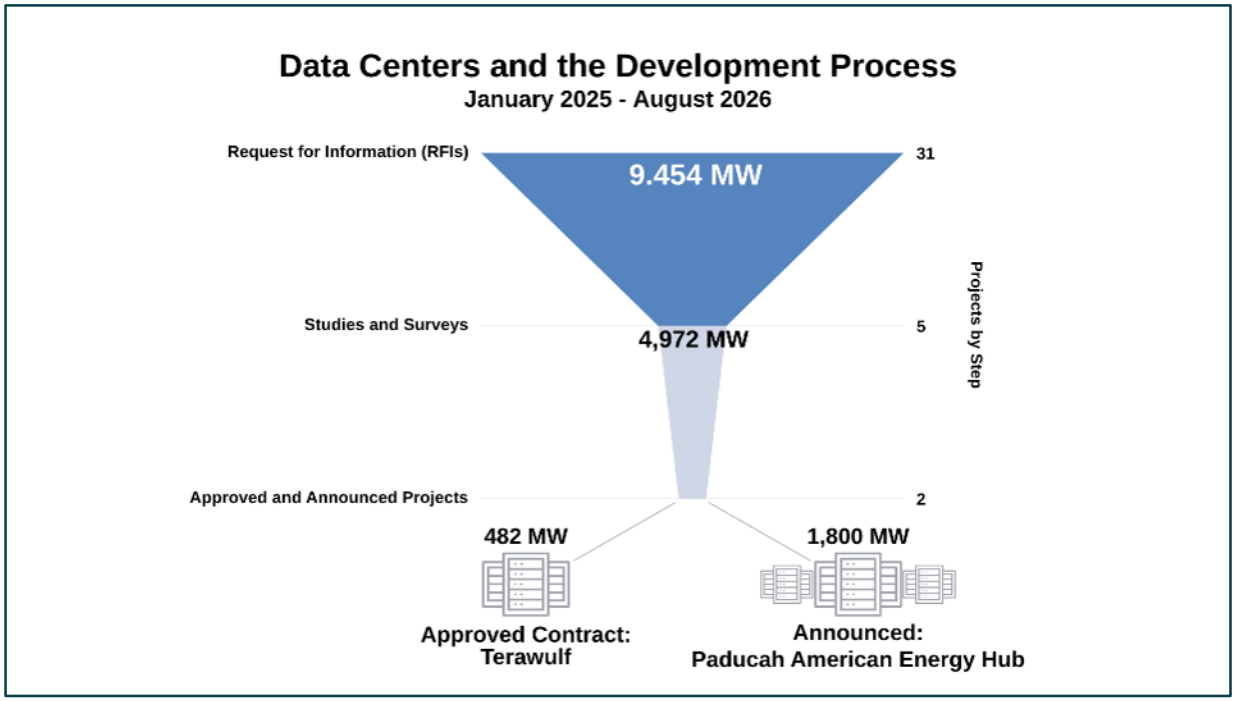
[23] *Id*., Order (Ky. P.S.C. Aug. 21, 2026).

one has been publicly announced but has not entered into a service contract;[24] and the remaining three confidential development prospects have not progressed beyond preliminary evaluation. Big Rivers remains focused on protecting its Members from unnecessary development costs and financial risk. After initial discussions, developers who wish to move forward must cover the costs of site evaluations, transmission studies, and other due diligence activities. As referenced above, one viable project has entered into contract negotiations with Big Rivers, with a customized agreement structured to protect members from higher energy costs and preserve system reliability. *See* Figure 1.2.8(a) below for an illustration of the development process of data centers from RFI to contract from January 2025 through July 2026.

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[24] See *DOE Site in Western Kentucky Revitalized with Data Center Campus and Dedicated Energy Project, Creating Jobs and Protecting Residents and Businesses from Costs* (July 29, 2026), available at https://www.investor.nexteraenergy.com/news-and-events/news-releases/2026/07-29-2026-133109921 (announcing plans to develop an artificial intelligence and high-performance computing data center campus at the former Paducah Gaseous Diffusion Plant site in western Kentucky).

Figure 1.2.8(a) [25]



Based on the principles and components discussed above, Big Rivers intends to further formalize this cost structure with the development of a new tariff. Subject to Board approval, Big Rivers plans to submit proposed tariff sheets to the Commission during Q4 of 2026.

1.2.9 Planning Goals and Objectives[26]

Big Rivers initiated the 2026 IRP in collaboration with ACES to reassess long-range strategic resource plans and satisfy the three-year filing requirement for IRPs with the Commission. Big Rivers' 2026 IRP is a comprehensive long-term

[25] The contract referenced at the bottom of Figure 1.2.8(a) relates to the data center project at the former Century Aluminum facility in Hancock County. *See Electronic Tariff Filing of Big Rivers Electric Corporation of a Retail Electric Service Agreement with Justified DataPower LLC a Subsidiary of TeraWulf Inc.* , Ky. P.S.C. Case No. 2026-00115.

[26] Responsive to 807 KAR 5:058, Section 5(1).

planning document that outlines how the Company will continue providing reliable, affordable, and lower risk electric service to its members. The IRP models Big Rivers' current supply and demand portfolio, evaluating the potential retirement of the existing coal-fired and natural gas-fired resources while exploring new resource options to meet member needs. Through capacity expansion modeling, scenario analysis, and sensitivity analysis, this IRP identifies potential strategies that balance cost, reliability, and risk. It also provides guidelines that Big Rivers can use for future planning as market conditions, regulations, and portfolio priorities evolve. This IRP is designed to comply with the IRP regulatory requirements and Kentucky statutory law while preparing for Big Rivers' evolving needs. The plan integrates system forecasting, resource adequacy analysis, policy evaluation, and scenario modeling to form a forward-looking strategy that guides Big Rivers from 2027 through 2050, with 2026 serving as the base year.[27]

During development of the 2026 IRP, Big Rivers also conducted a public IRP Open House to provide interested stakeholders, member-owner representatives, and the public an opportunity to learn about the IRP process, review planning considerations, and submit comments for consideration during development of the IRP. In advance of the Open House, Big Rivers published notice of the event in newspapers throughout its service territory to provide public

[27] Net present value results for Present Value Revenue Requirements ("PVRR") and Levelized Generation Cost ($/MWh) are for 2027 through 2050 for full period results and 2027 through 2041 for 15-year results, all reported in 2026 dollars.

awareness and encourage participation. Information regarding the Open House and opportunities for stakeholder engagement were also made available on Big Rivers' website at https://www.bigrivers.com/irp.html.

Key planning objectives in this IRP include the following:

- Identify a resource portfolio that can provide reliable, low-cost energy to Big Rivers' Member Owners over the next 15 years that also meets MISO resource adequacy requirements
- Compare alternative plans for Green's two natural gas steam turbines, including examining the cost-effectiveness of adding fuel oil backup to the Green units to improve resource fuel availability and MISO winter capacity accreditation
- Compare alternative plans for Wilson's coal-combustion steam turbine, including examining the cost-effectiveness of investing in Wilson to improve its performance and reliability
- Determine a replacement strategy for the Robert Reid Combustion Turbine (the "Reid CT"), due to the unit's catastrophic forced outage.

1.3 IRP SUMMARY[28]

Big Rivers' 2026 IRP evaluates resource needs and alternative supply strategies from 2027 through 2050.[29] The analysis was designed to identify resource strategies that provide reliable and affordable service while maintaining flexibility to respond to future changes in load growth, fuel markets, environmental regulations, technology costs, and resource adequacy requirements. The IRP evaluates multiple planning scenarios, retirement strategies, sensitivity cases, stochastic simulations, and scorecard metrics to determine which resource portfolios perform best across a broad range of potential future conditions.

The 2026 IRP includes retirement analysis for the Wilson and Green generating stations, considering years that Big Rivers could feasibly comply with Kentucky's retirement statutes[30] and other factors, including the interconnection process for replacement generation.[31] A central finding of Big Rivers' IRP is that the existing Wilson and Green generating stations continue to provide significant economic and reliability value to Big Rivers' system. In fact, across the scenarios

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[28] Responsive to 807 KAR 5:058, Section 5.

[29] See Chapter 6, *Electric Integration Analysis,* Section 2.1 (*Planning Horizon*), for a detailed discussion on the extended planning horizon.

[30] See KRS 278.264 and KRS 164.2807, which establish requirements applicable to proposed retirement of fossil fuel-fired electric generating facilities.

[31] See *In the Matter of: Electronic 2023 Integrated Resource Plan of Big Rivers Electric Corporation*, Case No. 2023-00310, Appendix to Order, Commission Staff Report on the 2023 Integrated Resource Plan of Big Rivers Electric Corporation, at 45 (Ky. P.S.C. Aug. 20, 2024) (recommending that future modeling consider statutory retirement, construction, and interconnection timelines).

considered most likely to occur, portfolios that keep these resources in operation consistently outperform portfolios that require their retirement and replacement.

The IRP also evaluated alternatives for addressing the mechanical loss of the Reid CT, which has been unavailable since August 24, 2024. Because the Reid CT is a fossil fuel-fired generating resource, Kentucky law requires retiring dispatchable resources to be replaced with the same or higher dispatchable electric generating capacity, unless the utility can demonstrate that equivalent capacity is not necessary to provide reliable service.[32] The IRP's analysis found that once the Green Fuel Oil Backup Project results in the additional MISO capacity accreditation the project provides sufficient accredited capacity to offset the loss of the Reid CT and maintain resource adequacy. As a result, the IRP demonstrates that replacement of the Reid CT with a dedicated generation resource is not necessary to maintain reliable service. Therefore, the Reid CT falls within the statutory exception, and Big Rivers does not identify a need for a dedicated replacement resource. Further, the Green Fuel Oil Backup Project is expected to provide accredited capacity [redacted], strengthening the system's capacity position and supporting continued reliability. In parallel, Big Rivers is evaluating cost-effective Demand Response ("DR") opportunities, through pilot programs, that can provide greater operational flexibility and complement traditional Demand Side

[32] See KRS 278.264(2)(a)(4).

Management ("DSM") portfolios. Collectively, these initiatives enhance resource adequacy, system flexibility, and planning optionality, allowing Big Rivers to more effectively evaluate the timing and need for future generation additions as load growth, wholesale market conditions, resource adequacy requirements, and applicable regulatory policies continue to evolve through future IRPs.

Across all scenarios and resource strategies evaluated, the Green Fuel Oil Backup Project is selected in every portfolio, demonstrating the substantial reliability and accreditation value associated with improved fuel flexibility at Green. The project increases winter accredited capacity by approximately 144 MW and significantly improves winter fuel assurance. The analysis demonstrates that retaining existing dispatchable generation, supported by targeted fuel reliability investments, is more economical than constructing replacement resources, while continuing to provide the firm capacity required to satisfy MISO's resource adequacy requirements.

Similarly, Wilson is selected in the Reference Case and Natural Gas Infrastructure Challenges scenarios to run throughout the planning period. As explained fully Section 6.7.8, Wilson Reliability Projects, Big Rivers identified a series of maintenance projects, replacing and repairing existing components that would restore the Wilson unit and increase its reliability. The cost of these projects was added to the modeling and Wilson continued to be selected.

The IRP evaluates four planning futures. The Reference Case and Natural Gas Infrastructure Challenges scenarios represent the futures Big Rivers consider

most likely to occur. The Low Load and Natural Gas Price and High Regulatory scenarios serve as bookend futures that test portfolio resiliency under lower-growth and higher-regulation conditions. Although portfolio outcomes vary across these futures, each analytical framework employed in the 2026 IRP reaches the same general conclusion: preserving and improving the existing dispatchable fleet produces lower-cost portfolios and stronger reliability and resilience than retirement and replacement strategies.

Figure 1.3(a)

2026 IRP Scorecard

		Affordability (Reference Case Assumptions)				Reliability		Risk and Opportunity		Sustainability
	Portfolio	15-Year Levelized Generation Cost ($/MWh 2027-2041)	Full Study Levelized Generation Cost ($/MWh 2027 - 2050)	15-Year PVRR ($MM 2027 - 2041)	Full Study PVRR ($MM 2027 - 2050)	Dispatchable Capacity Divided by Big Rivers' Winter CP 2046	Dispatchable Firm Capacity Divided by Big Rivers' Winter CP 2046	Opportunity: Stochastic P5 Full Study ($/MWh 2027-2050)	Risk: Stochastic P95 Full Study ($/MWh 2027-2050)	Total CO_2 Emissions (Million Tons)
Model Optimization	Reference Case	$65.03	$68.89	$2,982	$4,291	161%	106%	$66.11	$71.77	92.5
	Natural Gas Infrastructure Challenges	$66.12	$70.63	$3,032	$4,400	161%	106%	$67.36	$73.32	90.1
	Low Load and Natural Gas Prices	$65.82	$74.06	$2,743	$4,028	163%	102%	$68.35	$80.91	66.2
	High Regulatory (Carbon Tax)	$86.38	$91.71	$4,325	$6,433	124%	81%	$81.73	$106.23	46.8
	High Regulatory (Carbon Tax) Kentucky Law	$88.99	$93.17	$4,456	$6,536	130%	85%	$82.92	$108.03	47.6
Fixed Retirements	Reference Case	$65.74	$75.33	$3,014	$4,692	120%	95%	$71.17	$80.58	79.9
	Natural Gas Infrastructure Challenges	$66.69	$76.23	$3,058	$4,748	113%	90%	$70.38	$81.47	79.6
	Low Load and Natural Gas Prices	$63.96	$70.95	$2,665	$3,858	121%	96%	$68.20	$74.78	79.3
	High Regulatory (Carbon Tax)	$81.07	$90.40	$4,059	$6,341	103%	82%	$83.64	$99.57	75.4
	High Regulatory (Carbon Tax) Kentucky Law	$80.43	$89.00	$4,028	$6,243	98%	78%	$82.30	$98.10	74.8

As summarized in Figure 1.3(a) above, the IRP Scorecard demonstrates that the Model Optimization Reference Case portfolio provides the strongest overall balance of affordability, reliability, and risk management. In addition to achieving one of the lowest levelized generation costs, the Reference Case portfolio provides substantial excess dispatchable and accredited capacity beyond minimum resource adequacy requirements. The portfolio provides capacity exceeding Big Rivers' MISO requirements and forecasted coincident summer peak load beginning in 2029 and coincident winter peak load beginning in 2032, with that capability maintained through the remainder of the planning horizon. While the IRP model is constrained only to satisfy MISO resource adequacy requirements, the Green Fuel Oil Backup Project preserve significant low-cost accredited capacity beyond the minimum requirement. This surplus capacity provides a prudent reliability buffer against load forecast uncertainty, future changes in MISO's resource adequacy construct, and year-to-year variability in resource accreditation and generating unit performance.

Additionally, this portfolio achieves one of the lowest levelized generation costs under common Reference Case assumptions while maintaining the highest levels of dispatchable and accredited capacity across the portfolios evaluated. In contrast, portfolios that retire and replace Green and Wilson (Fixed Retirements) generally exhibit higher long-term costs, lower dispatchable capacity margins, and greater exposure to future market and development risk. Similarly, while the High Regulatory portfolios achieve lower emissions, they do so at substantially

higher costs and have lower reliability margins. Together, the affordability, reliability, and stochastic risk metrics indicate that portfolios retaining Green and Wilson are consistently more resilient and provide better overall value to Big Rivers' members than portfolios requiring retirement of existing units and the addition of replacement generation.

Based on the results of the Scenario Analysis, Cross-Scenario Sensitivity Analysis, Stochastic Analysis, and IRP Scorecard Evaluation, the preferred portfolio identified through the 2026 IRP is the Model Optimization Reference Case portfolio. This portfolio maintains Green and Wilson through the planning horizon, implements the Fuel Oil Backup Project at Green, incorporates cost-effective DSM programs, and provides flexibility to add renewable resources when market conditions support them. The portfolio provides the strongest overall combination of affordability, reliability, risk management, and long-term planning flexibility.

Accordingly, Big Rivers concludes that continued operation of Green and Wilson, supported by targeted reliability projects and ongoing DSM efforts, represents the most prudent long-term resource strategy for serving its members. This plan maintains compliance with applicable reliability requirements, minimizes long-term costs, preserves optionality as future conditions evolve, and provides a durable foundation for future resource planning decisions.

Chapter 2

SIGNIFICANT DEVELOPMENTS AND CHANGES SINCE 2023 IRP



2. SIGNIFICANT DEVELOPMENTS AND CHANGES SINCE THE 2023 IRP[33]

As earlier mentioned, the utility resource planning process is inherently continuing in nature, necessarily subject to ongoing review, confirmation, and challenge considering 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 most recently filed plan, 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 2026 IRP.

2.1 Changes to Load Forecast

As was the case with respect to Big Rivers' 2023 IRP, Big Rivers chose Clearspring Energy Advisors, LLC of Madison, Wisconsin, to prepare the 2025 Long–Term Load Forecast. 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.

[33] Responsive to 807 KAR 5:058, Section 6.

The methodologies Clearspring used to develop the Load Forecast from the 2023 IRP are very similar to those used for the 2025 load forecast used in this IRP, however there was one adjustment made to the methodology used in the 2025 forecast. Individual consumer load factors were used in the creation of the Direct Serve peak forecasts, while in previous load forecasts a class average load factor at each Member system was used.

2.2 Significant State Regulatory Events

2.2.1 Overview of Regulatory Activity

Since filing its 2023 IRP, Big Rivers has participated in numerous Commission proceedings involving rate mechanisms, special contracts, and electric utility regulatory matters. While many of these proceedings do not directly affect the modeling or resource portfolios presented in this 2026 IRP, some provide important context regarding Big Rivers' long-term load obligations, contractual relationships, resource development trends, and regulatory planning environment.

A significant development during the reporting period was the Commission's approval of amendments to the long-term wholesale power contracts between Big Rivers and its three Member-Owners ("Wholesale Power Contract Amendments").[34] The amendments extend the contractual term through December 31, 2061, provide for automatic five-year extensions thereafter absent

[34] See Ky. P.S.C. Tariff Filing Nos. TFS 2025-00553, TFS 2025-0554, and TFS 2025-00555.

action by the parties, and establish a Shared Services Budget Committee within the contractual framework. Collectively, these provisions reinforce the long-term alignment of Big Rivers and its Member-Owners and provide planning certainty extending well beyond the time horizon evaluated in this IRP.

The Commission also approved several special contracts and contract amendments that illustrate evolving load characteristics and resource developments within Big Rivers' service territory, including:

- Amendments and new service agreements supporting the expansion of Block Mining Inc.'s existing operations and the development of additional facilities.[35] [36]
- A Load Modifying Resource Agreement enabling Pratt Paper (KY), LLC's participation in MISO demand response programs.[37]
- A power purchase and interconnection agreement for a qualifying solar facility at McCracken County High School.[38]

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[35] See Ky. P.S.C. Tariff Filing Nos. TFS2023-00388 (filed Aug. 31, 2023) and TFS2025-00417 (filed Sept. 25, 2025).

[36] See Ky. P.S.C. Tariff Filing Nos. TFS2026-00037 (New Commerce Pake Site) (filed Jan. 28, 2026) and TFS2026-00038 (Shell Site) (filed Jan. 28,2026).

[37] See *In the Matter of: Electronic Joint Special Contract Filing of Big Rivers Electric Corporation and Kenergy Corporation*, Case No. 2026-00056, Order (Ky. P.S.C. Mar. 31, 2026) (filed initially under Ky. P.S.C. Tariff Filing No. TFS2026-00068).

[38] See Ky. P.S.C. Tariff Filing No. TFS2025-00261 (filed June 10, 2025).

- Several agreements for backup electric service to individual operators of solar facilities, including Green River Solar, LLC,[39] Unbridled Solar, LLC,[40] Sebree Solar, LLC,[41] and Sebree Solar II, LLC.[42]

Although these agreements generally do not serve as direct inputs to the resource planning models, they provide insight into emerging customer load requirements, demand-side participation opportunities, and the continued development of utility-scale solar resources within the Big Rivers service territory. In particular, the backup service agreements demonstrate that a significant amount of solar generation is being developed within the region and may influence future operational and planning considerations.

Beyond utility-specific applications, the Commission has also initiated broader policy and administrative proceedings affecting Kentucky's electric sector. One such proceeding is the Commission's investigation of nuclear energy, generation, storage, and related matters, which was established to facilitate stakeholder discussions regarding the opportunities and challenges associated with nuclear development in the Commonwealth.[43] The proceeding follows legislative actions removing Kentucky's nuclear construction moratorium and directing the Commission to prepare for the potential regulation of nuclear

[39] See Ky. P.S.C. Tariff Filing No. TFS2025-00161 (filed Apr 1. 2025).

[40] See Ky. P.S.C. Tariff Filing No. TFS 2025-00181 (filed Apr. 16. 2025).

[41] See Ky. P.S.C. Tariff Filing No. TFS2025-00267 (filed June 12, 2025), Amended under TFS2026-00187 (filed May 1, 2026).

[42] See Ky. P.S.C. Tariff Filing No. TFS2026-00188 (filed May 1, 2026).

[43] *In the Matter of: Electronic Investigation of Nuclear Energy, Generation, Storage, and Related Matters,* Case No. 2025-00186, Order (Ky. P.S.C. June 16, 2025).

facilities. The General Assembly also directed the Commission to consider amendments to its IRP regulations addressing the treatment of generation resources, including nuclear generation.

2.2.2 Conclusion

The regulatory developments discussed above help define the environment in which Big Rivers conducts long-term resource planning. Some, such as the Wholesale Power Contract Amendments, directly affect planning assumptions by strengthening long-term member relationships and load commitments. Others provide context regarding emerging technologies, changing customer requirements, demand-side opportunities, and resource development trends. While not all are reflected as discrete modeling inputs, each contributes to the broader planning framework within which Big Rivers evaluates future resource needs and maintains reliable, cost-effective service.

2.3 Regulatory Climate

2.3.1 Overview of Regulatory Climate

Big Rivers integrated resource planning focuses on maintaining system reliability, compliance, and cost-effectiveness in a dynamic regulatory environment. As a Member-owned electric cooperative operating on a cost-of-service basis, Big Rivers' resource decisions directly affect its Member-Owners and the consumers they serve. This structure reinforces the need for prudent risk management, reliable performance across a wide range of conditions, and

economic stability within its Members' service territories, given the continuing evolution of the regulatory climate.

The regulatory environment affecting Big Rivers is shaped by a convergence of federal, regional, and state actions, with an increasing emphasis on maintaining electric system reliability. Understanding this regulatory climate provides important context for the 2026 IRP because it informs the assumptions, constraints, and sources of uncertainty that directly influence resource evaluation, scenario development, and the identification of prudent, least-cost portfolios.

2.3.2 Federal and Regional Regulatory Framework

Federal environmental regulations remain a primary driver of planning assumptions and are incorporated into the IRP through projected compliance costs, operational constraints, and the evaluation of unit retirement or repowering decisions. Additional details related to environmental regulation are provided in Chapter 5, Environmental, and Section 4, Regulatory Environment, Chapter 6, Electric Integration Analysis. Over the past three years, federal and regional regulatory policy has shifted toward a more reliability-focused and cost-conscious framework, reflecting the rapid transformation of the electric sector. This shift is characterized by greater emphasis on long-term planning under uncertainty, increased scrutiny of resource adequacy as the generation mix evolves, and stronger attention to cost allocation and ratepayer impacts.

Federal regulatory policy increasingly reflects a dual mandate: balancing environmental objectives with grid reliability, particularly all-hours resource

adequacy amid rising load, and consumer affordability, including the mitigation of capital-intensive compliance costs. This emphasis has become more pronounced in recent years as regulators respond to accelerating load growth, generator retirements, and the risk that dispatchable resources may exit the system faster than replacement capacity can be deployed. In the IRP, this shift is reflected through assumptions regarding retirement timing, replacement needs, and sensitivities reflecting regulatory and policy uncertainty impacting resource planning.

A central element of this evolving regulatory framework is Federal Energy Regulatory Commission's ("FERC") increased focus on long-term, scenario-based transmission planning. Through Order No. 1920 and related actions, FERC now requires regional transmission planning processes to evaluate long-term system needs over extended planning horizons using multiple scenarios and to more explicitly consider cost allocation and state participation.[44] This represents a significant departure from prior, more reactive planning approaches and aligns transmission planning with the type of scenario-based analysis performed in this IRP. FERC Order No. 1920 bridges the historic gap between grid infrastructure

[44] See *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*, Order No. 1920, 187 FERC ¶ 61,068, PP 8-10 (2024) (adopting reforms requiring long-term regional transmission planning, evaluation of long-term transmission needs through multiple scenarios, and associated cost-allocation requirements); *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*, Order No. 1920-A, 189 FERC ¶ 61,115 (2024) (clarifying and expanding state participation in long-term regional transmission planning and cost-allocation processes).

and power supply by legally mandating regional transmission providers to proactively plan 20-year grid expansions around state-approved utility resource plans, projected fossil-fuel retirements, and expected clean generation growth.

At the same time, FERC has heightened its focus on resource adequacy and market design to address reliability risks associated with a changing resource mix. Recent actions addressing transmission planning, resource adequacy, capacity accreditation, and wholesale market design an effort to better align market outcomes with reliability needs.[45] These developments directly influence IRP modeling assumptions related to capacity value, reserve margins, and the relative contribution of dispatchable and non-dispatchable resources.

Within MISO, these federal policy directions have translated into ongoing reforms to resource adequacy requirements, capacity accreditation methodologies, and transmission planning processes.[46] Over the past three years, MISO has implemented and proposed changes intended to improve reliability outcomes, reduce price volatility, and better reflect the reliability contribution of different resource types. These changes directly affect IRP inputs related to planning reserve margins, capacity accreditation factors, and the cost of meeting resource adequacy obligations.

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[45] See *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*, Order No. 1920, 187 FERC ¶ 61,068 (2024), and related FERC proceedings concerning resource adequacy, capacity accreditation, and market design.

[46] See, e.g., MISO's Seasonal Resource Adequacy construct, Effective Load Carrying Capability ("ELCC") accreditation methodology, and Long-Range Transmission Planning ("LRTP") initiatives, which implement and respond to evolving federal reliability, resource adequacy, and transmission planning policies.

Additionally, both FERC and regional operators have increased their focus on integrating large and rapidly growing loads, including data centers and other energy-intensive customers. Recent regulatory actions emphasize ensuring that such loads can be accommodated without compromising system reliability or imposing unreasonable costs on existing customers.[47] In the IRP, these developments are reflected in scenario-based load growth assumptions and sensitivities addressing infrastructure requirements and cost allocation risks associated with large-load integration.

2.3.3 State Regulatory Considerations

At the state level, the Kentucky General Assembly and the Kentucky Public Service Commission have placed increasing emphasis on reliability and grid resilience. The enactment of KRS 278.264 establishes a rebuttable presumption against the retirement of fossil fuel-fired generation, reflecting legislative concern regarding reliability impacts associated with generation retirements. Likewise, KRS 164.2807 reflects a legislative policy favoring the preservation and continued operation of existing generation resources that support reliability and affordability through the establishment of the Electric Generation and Transmission Siting

[47] See, e.g., Federal Energy Regulatory Commission, *Letter from Chairman David Rosner to RTOs/ISOs on Large Load Forecasting* (Sept. 18, 2025) (discussing forecasting and planning challenges associated with data centers and other large energy users); Federal Energy Regulatory Commission, News Release: *FERC Launches Aggressive Targeted Action to Speed Large Load Integration* (June 18, 2026) (issuing Section 206 show cause orders directing RTOs/ISOs to justify or revise tariff provisions governing large load connections and cost allocation).

Research Fund. This statutory framework informs IRP assumptions regarding the continued operation and evaluation of existing generation assets and shapes the range of feasible resource portfolios considered.

In addition, recent legislative and policy developments reflect a broader focus on ensuring that new, large-scale loads are integrated in a manner that protects existing ratepayers.[48] Emerging statutory and regulatory frameworks addressing cost allocation, infrastructure responsibility, and service requirements for high-demand customers—such as data centers—are reflected in the IRP through load growth scenarios and sensitivities evaluating the timing, scale, and cost impacts of large-load additions.

The Commission has also initiated an ongoing administrative proceeding to investigate the potential role of nuclear generation in the Commonwealth, pursuant to legislative direction.[49] While no specific nuclear development is assumed in this IRP, the proceeding signals a potential expansion of feasible long-term resource options and is considered qualitatively in the development of long-term scenarios.

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[48] See, e.g., Ky. Exec. Order No. 2026-494 (Aug. 6, 2026) (directing the Kentucky Public Service Commission to prohibit utility rate increases designed to recover data center infrastructure costs from existing ratepayers); H.B. 544, 2026 Reg. Sess. (Ky. 2026) ("Kentucky Ratepayer Protection Act") (proposing require Commission approval of cost-allocation protections prior to interconnection of certain large-load customers, including data centers); see also *Ratepayer Protection Act*, H.R. __, 119th Cong. (2026) (proposing federal support for state frameworks designed to protect existing ratepayers from costs associated with large-load expansion).

[49] *In the Matter of: Electronic Investigation of Nuclear Energy, Generation, Storage, and Related Matters*, Case No. 2025-00186 (Ky. P.S.C. June 16, 2025).

2.3.4 Planning Under Regulatory Uncertainty

Given the pace and complexity of regulatory developments, Big Rivers explicitly incorporates regulatory uncertainty into its resource planning through ongoing monitoring, scenario analysis, and risk assessment. This includes evaluating potential changes in environmental requirements, market design, reliability standards, and load growth conditions.

By modeling a range of regulatory outcomes, the IRP assesses how different resource strategies perform under varying assumptions, supporting the identification of portfolios that are robust, flexible, and resilient to regulatory change.

2.4 Significant Changes – MISO

Big Rivers participates in the Midcontinent Independent System Operator, Inc. ("MISO") resource adequacy construct, which establishes seasonal obligations for Summer, Fall, Winter, and Spring. The seasonal construct reflects that reliability risk is no longer limited to the annual summer peak; risk can arise during winter morning and evening periods, summer evening solar ramp-downs, and shoulder-season maintenance periods.[50] MISO's reliability risk hours are moving away from the traditional peak hour as installed solar capacity increases. MISO's resource adequacy construct has continued to evolve since the 2023/2024

[50] *See* MISO FERC Electric Tariff, Module E-1; and MISO Resource Adequacy Business Practices Manual (BPM-011) (describing MISO's seasonal resource adequacy framework and seasonal planning reserve requirements).

seasonal construct transition and is expected to change further as MISO implements and refines Direct Loss of Load ("DLOL") accreditation for the 2028/2029 Planning Year and beyond. This section summarizes key MISO resource adequacy changes and supports Big Rivers' use of Big Rivers' coincident seasonal peak with MISO, rather than traditional non-coincident or Big Rivers' seasonal system coincident peak, for IRP planning.

MISO's core physical reliability benchmark is the Initial Planning Reserve Margin Requirement ("Initial PRMR"). Initial PRMR represents the Zonal Resource Credits ("ZRCs") a Load Serving Entity ("LSE") needs to meet its Resource Adequacy Requirements and reliably serve load each season. MISO calculates Initial PRMR using the LSE's seasonal MISO coincident peak demand forecast, adjusted for full requirements purchases and sales, transmission losses, and the MISO Planning Reserve Margin ("PRM") established through Loss of Load Expectation ("LOLE") studies.[51]

The PRM is developed through LOLE modeling, a probabilistic reliability measure that evaluates expected supply shortfalls after accounting for load uncertainty, outages, seasonal risk, resource performance, and available capacity. MISO's resource adequacy construct is designed around the widely used reliability standard of one expected loss-of-load day in ten years, or 0.1 day per year. Initial PRMR is therefore not an arbitrary reserve margin or simple peak-load adder; it is

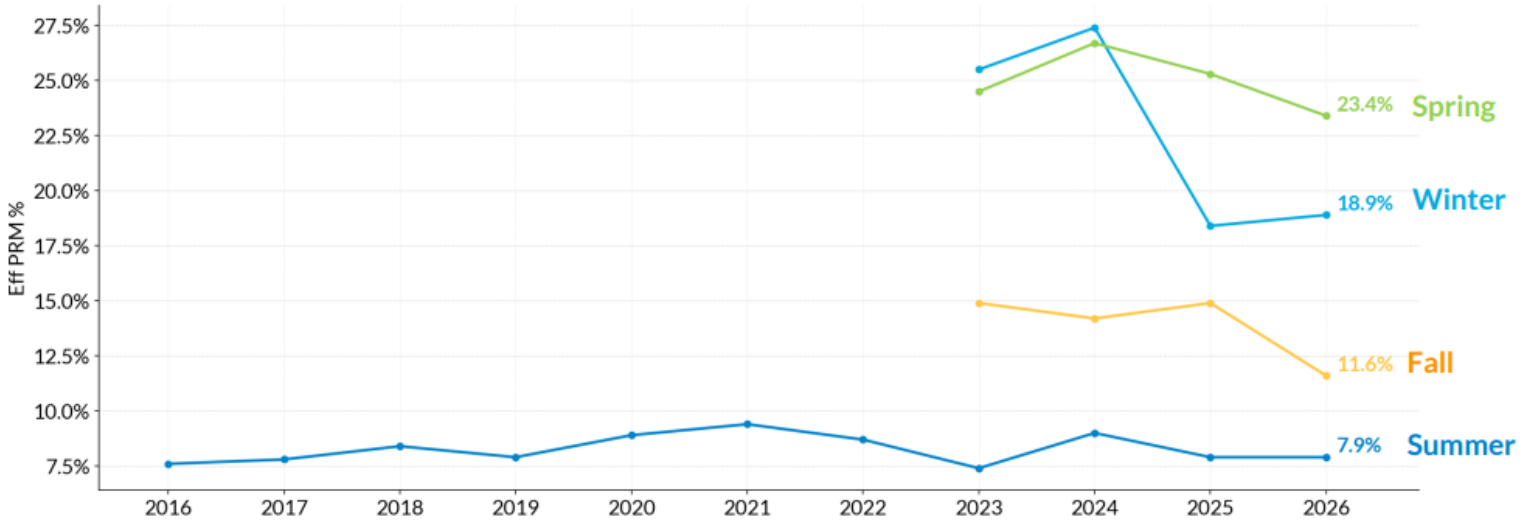
[51] *Id.*

the LOLE-derived amount of accredited capacity needed to maintain reliability under MISO's regional planning construct.[52] Figure 3.4(a) shows how the PRM has changed over time and varies by season. Note that MISO transitioned to a seasonal planning construct starting in the 2023-2024 planning year, so previous years in Figure 2.4(a) only have an annual PRM value.

[52] See MISO FERC Electric Tariff, Module E-1; and MISO Resource Adequacy Business Practices Manual (BPM-011) (describing MISO's seasonal resource adequacy framework and seasonal planning reserve requirements).

Figure 2.4(a)[53]

Capacity Planning Reserve Margin History



	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Summer PRM	7.6%	7.8%	8.4%	7.9%	8.9%	9.4%	8.7%	7.4%	9.0%	7.9%	7.9%
Fall PRM								14.9%	14.2%	14.9%	11.6%
Winter PRM								25.5%	27.4%	18.4%	18.9%
Spring PRM								24.5%	26.7%	25.3%	23.4%

[53] Figure reproduced from *MISO, Planning Resource Auction Results for Planning Year 2026/27* at 39 (updated May 22, 2026) available at: https://cdn.misoenergy.org/2026%20PRA%20Results%20Posting%2020260522%20-%20Corrections754715.pdf .

Because Initial PRMR is based on Big Rivers' MISO coincident peak demand, Big Rivers' planning obligation should not be treated as a traditional non-coincident peak load requirement or Big Rivers coincident peak. Planning to Big Rivers' peak load would ignore the load and resource diversity embedded in MISO's regional resource adequacy construct and would overstate the accredited capacity needed to serve member load reliably. It could also create excess capacity length and expose members to unnecessary mark-to-market risk in MISO's Planning Resource Auction ("PRA"). The appropriate physical planning target is Big Rivers' Initial PRMR, supported by owned and contracted accredited resources, rather than an islanded peak-load self-sufficiency target.

MISO's capacity market also changed with implementation of the Reliability-Based Demand Curve ("RBDC"). FERC accepted MISO's tariff revisions to implement a downward-sloping RBDC in the PRA beginning with the 2025/2026 Planning Year, replacing the prior vertical demand curve. RBDC changes the PRA clearing process but does not change Initial PRMR's role as the physical reliability planning benchmark. Under RBDC, Final PRMR is determined through auction clearing and may be higher or lower than Initial PRMR. Final PRMR reflects the market-clearing value of incremental capacity

and should not be treated as an automatic requirement to build our own generation above or below Initial PRMR.[54]

RBDC is consistent with the economics of Cost of New Entry ("CONE") and Net Cost of New Entry ("Net CONE"). CONE reflects the capital, operating, financial, and other costs of acquiring a new generation resource. Net CONE subtracts expected energy market revenues from CONE, leaving the cost to be recovered through capacity. MISO's RBDC framework is calibrated so long-run average seasonal capacity prices support Net CONE under equilibrium conditions, while lower prices can occur with surplus capacity and higher prices can occur when capacity is scarce.[55]

Using Final PRMR above Initial PRMR as an IRP build target would not be cost-effective. If capacity market prices are below Net CONE, and Net CONE is below the gross cost of owning new capacity, purchasing incremental capacity through the auction is less costly for customers than building or retaining excess resources solely to cover potential increases in Final PRMR. If capacity prices exceed Net CONE, Big Rivers' Final PRMR should be lower than Initial PRMR, and the portfolio would benefit from higher capacity prices and ZRC length in the auction.

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[54] *See* Midcontinent Independent System Operator, Inc. (MISO), Reliability-Based Demand Curve tariff filing and related pleadings, FERC Docket No. ER23-2977 (describing the determination of Final PRMR through the auction-clearing process).

[55] *See* MISO, Reliability-Based Demand Curve tariff filing and related pleadings, FERC Docket No. ER23-2977 (describing the determination of Final PRMR through the auction-clearing process).

Resource accreditation is also central to IRP planning. MISO assigns Seasonal Accredited Capacity ("SAC") to qualified Planning Resources, and those values determine each resource's contribution toward PRMR. MISO's accreditation framework, which recognizes that nameplate capacity is not the same as reliable capacity contribution. Resource Adequacy ("RA") Hours, or Tier 2 hours, are seasonal high-risk hours used to measure availability when capacity is most needed. MISO targets 65 RA Hours per season, beginning with Maximum Generation Emergency hours then adding the lowest operating-margin hours. Tier 1 measures availability during non-RA Hours and receives a 20% weight; Tier 2 measures availability during RA Hours and receives an 80% weight. MISO uses the weighted results to calculate Intermediate Seasonal Accredited Capacity (ISAC), which is then converted into ZRCs. [56]

MISO is transitioning toward DLOL accreditation to better align resource accreditation with availability during the hours when the system is most at risk. MISO's accreditation materials state that DLOL considers expected performance during Loss of Load hours and low-margin hours, applies a common framework across resource types, and aligns planning reserve margin requirements, risk, availability, and accreditation. Capacity accreditation assumptions for existing

[56] See MISO FERC Electric Tariff, Module E-1, and *MISO Resource Adequacy Business Practices Manual* (BPM-011) (describing the methodology used to establish planning reserve requirements and evaluate resource adequacy).

resources can be found in Section 6.7.1, Existing Resources, of this report with new resources in Section 6.8.7, New Resource Accreditation.

DLOL should be understood as a consistent reliability accounting framework, not simply as a reduction in individual resource capacity values. MISO's accreditation materials explain that PRMR remains based on the sum of accredited values in the LOLE model plus the adjustment needed to meet the applicable reliability criterion. Lower total accreditation values under DLOL result in a correspondingly lower PRMR, while future PRMRs may move up or down depending on the planning year, resource mix, and measured system risk. Accreditation changes and load-serving obligations must therefore be evaluated together.[57] Section 6.7.4, Current Summer and Winter Firm Capacity Position, provides a comparison of existing unit accreditation to Big River's summer and winter PRMR.

North American Electric Reliability Corporation's ("NERC") 2025 Long-Term Reliability Assessment reinforces the need for balanced, seasonal, and risk-based planning in MISO. NERC identified MISO as Normal Risk in 2026, Elevated Risk in 2027, and High Risk beginning in 2028 under base assumptions, citing escalating demand forecasts, uncertainty around resource commercialization, data center load growth, reduced accredited thermal capacity, and risk during summer evenings, winter morning/evening hours, and spring/fall maintenance periods. NERC's

[57] See MISO, *Resource Accreditation White Paper,* Version 2.1 (Mar. 2024) available at https://cdn.misoenergy.org/Resource%20Accreditation%20White%20Paper%20Version%202.1.pdf .

sensitivity analysis indicates that timely resource additions could reduce MISO risk, reinforcing the need for disciplined resource planning and careful monitoring of load growth, retirements, accreditation changes, and market outcomes.[58]

Big Rivers' diverse portfolio of coal, natural gas, and renewable resources supports MISO's seasonal construct, DLOL risk-based framework, and NERC's assessment of MISO reliability needs. Dispatchable thermal resources provide capacity and energy availability during abnormal weather conditions, evening ramps, low-renewable-output periods, and emergency events. Renewable resources diversify energy supply, reduce fuel-price exposure, and hedge changing environmental and market conditions.

For this IRP, Big Rivers uses MISO-provided DLOL accreditation indicatives, MISO DLOL PRM indicatives, Big Rivers' coincidence factors with MISO, and past and expected future resource performance as the appropriate physical planning target for owned and contracted accredited resources. This benchmark is derived from MISO forecasts, LOLE modeling, and DLOL indicatives designed to maintain grid reliability. This approach maintains reliability, preserves the benefits of RTO participation, and protects customers from overbuilding beyond the level needed to satisfy MISO's reliability-based planning requirement.

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[58] *See* N. Am. Elec. Reliability Corp. (NERC), *2025 Long-Term Reliability Assessment,* available at https://www.nerc.com/our-work/assessments/long-term-reliability-assessments.

2.5 Market Trends Summary

The electric industry is undergoing a significant transition that directly affects long-term resource planning. Across MISO and the broader U.S. power sector, the key planning themes are load-growth uncertainty, tighter reserve margins, increased focus on resource performance, rising reliability risk during non-traditional peak hours, and higher costs to build new dispatchable capacity.

Solar growth in MISO has accelerated rapidly and is materially changing the region's planning outlook. In June 2024, MISO had approximately 6 GW of installed solar capacity; by June 2026, installed solar exceeded 20 GW.[59] This growth is reshaping price shapes with low-cost midday energy and shifting price volatility risk into evening, morning, winter, and shoulder-season hours when solar output is limited. For IRP planning, this trend underscores the need to evaluate resources based on when they provide reliability and energy value, not only annual energy production. A balanced portfolio should account for solar-driven price-shape changes while maintaining sufficient dispatchable, fuel-secure, and accredited capacity during stressed system conditions.

Winter reliability risk is also increasing. MISO's seasonal construct recognizes that reliability needs are no longer limited to the traditional summer peak. Cold weather events can create simultaneous pressure from high load,

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[59] *See* MISO, *Seasonal Readiness Workshop: Summer 2026*, (May 6, 2026), available at https://cdn.misoenergy.org/20260506%20Summer%20Readiness%20Workshop%20Presentation_UPDATED755608.pdf .

generator outages, fuel supply limitations, and natural gas pipeline constraints. As the region becomes more dependent on natural gas-fired generation, planning assumptions should reflect the value of firm fuel arrangements, natural gas price volatility, dual-fuel options, and other resources that can perform during constrained winter conditions.

Nationally, load growth is accelerating after years of relatively flat demand. Data centers, electrification, manufacturing, and broader economic development are increasing uncertainty around future peak demand and energy requirements. This adds pressure to capacity needs, transmission development, interconnection queues, and local infrastructure. At the same time, new resource costs have increased due to higher equipment costs, longer development timelines, supply chain constraints, labor limitations, interconnection delays, and permitting challenges.

Together, these trends support a planning approach that emphasizes reliability, fuel diversity, dispatchability, and flexibility. The 2026 IRP continues to evaluate a balanced portfolio that can manage changing price shapes, maintain capacity value during MISO's highest-risk hours, reduce winter fuel exposure, and preserve optionality under uncertain load growth and resource cost conditions.

2.6 Tabular Summary[60]

Section 6 of 807 KAR 5:058 requires a narrative and tabular summary of changes from the most recent IRP in load forecasts, resource plans, assumptions and methodologies. Figure 2.6(a) provides a comparison of these changes. The comparison is intended to explain changes to inputs and methods; it does not restate every update described above or contained in the load, DSM, transmission, environmental, or financial supporting materials.

Figure 2.6(a)

Significant Changes Since the 2023 IRP

Topic	2023 IRP treatment	2026 IRP treatment	Planning implication
Planning horizon and method	EnCompass expansion and production-cost analysis; regulatory forecast through 2037 with extended economic analysis	2026 base year; integrated 2027-2050 expansion, 8,760-hour dispatch, cross-scenario, stochastic, economic resource retirement optimization, and scorecard analyses	Broader evaluation of timing, robustness, and downside risk
Reid CT	Modeled in service as a 65 MW existing resource	No modeled capacity or energy contribution following the August 2024 mechanical outage	Replacement need is demonstrated through the seasonal portfolio analysis
Green Station	Natural-gas operation and potential retirement were evaluated	Fuel-oil backup and early retirement are explicit selectable alternatives	Winter fuel assurance, reliability, and accreditation are central decision criteria
Wilson Station	Continued operation and long-term portfolio role were evaluated	Continued operation and early retirement with replacement are explicit selectable alternatives	Preserves a fuel-secure, dispatchable resource
Resource accreditation	Then-current MISO seasonal accreditation	Updated seasonal Planning Reserve Margin (PRM), Direct Loss of	Installed MW and accredited MW are

[60] Responsive to 807 KAR 5:058, Section 6.

Topic	2023 IRP treatment	2026 IRP treatment	Planning implication
	and reserve assumptions	Load (DLOL) transition, Schedule 53 performance, and winter risk	evaluated separately, particularly in winter
Load and large-load risk	Prior member forecast and economic-development assumptions	Updated forecast, 2032 industrial-obligation step-down, and explicit monitoring of large-load development	Resource timing remains conditional on committed load and transmission readiness
DSM	Completed DSM potential assessment, but DSM resources were not incorporated into the preferred resource strategy and had limited influence on resource selection	Developing a portfolio of cost-effective demand response programs identified through a dedicated Market Potential Study (MPS) and modeled DR/DSM as a fixed resource in the IRP	DR programs will be designed to contribute directly to reducing peak demand and energy requirements, improve resource adequacy and can defer future generation additions
Resource alternatives	Natural gas, renewable, storage, DSM, purchases, and emerging technologies were screened	Updated cost and performance assumptions; stronger executability screen for emerging technologies	Model selections are limited to resources with supportable cost, schedule, and operating data

The principal change in Big Rivers' planning approach is not a predetermined technology transition. It is a more explicit comparison of the cost and reliability value of preserving existing dispatchable resources against the cost, lead time, and performance risk of replacement resources. Big Rivers' 2026 IRP also places greater emphasis on winter reliability, fuel assurance, and resource-specific accreditation than the 2023 IRP, because the MISO construct and observed market risk profile have changed.

Chapter 3

LOAD FORECAST



3. LOAD FORECAST [61] [62]

3.1 Load Forecast Introduction

Clearspring Energy Advisors, LLC, which prepared Big Rivers' 2023 Long-Term Load Forecast, was again selected by Big Rivers and its Members to prepare this 2025 electric load forecast through 2044. The forecasting process relies on internal system data, third-party demographic and economic data, and insight from Big Rivers' and the Members' 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 contains more detailed aspects of the analysis.

For purposes of discussing Big Rivers' load forecast and capacity planning requirements, it is helpful to distinguish among the following terminology for peak demand used in this report:

- **Member Non-Coincident Peak (NCP):** The annual peak demand of an individual Big Rivers Member, without regard to when the other Members or the Big Rivers system peak occurs.

[61] Responsive to 807 KAR 5:058, Section 5.

[62] Responsive to 807 KAR 5:058, Section 7.

- **Member Coincident Peak (CP):** The demand of an individual Member at the time of the Big Rivers System Peak.

- **Big Rivers Coincident Peak (CP):** The maximum demand of the Big Rivers system, without regard to when the MISO system peak occurs.

- **Big Rivers MISO Coincident Peak (CP):** Big Rivers' demand at the time of the applicable MISO system peak. This measure is used in determining Big Rivers' capacity planning requirements.

3.2 Big Rivers' Native System

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 (2020-2024) and the forecasts for the next 20 years.

Table 3.2(a)

Big Rivers' Native System Totals[63]

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
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	811,577	598.3	88.5	43.3%	51.3%
2023	2,097,660	1,167,083	490.4	225.4	48.8%	52.1%
2024	2,179,785	1,623,201	486.3	262.2	51.0%	57.8%
2025	2,238,259	1,785,062	455.2	267.2	56.1%	63.6%
2026	2,267,529	1,842,767	460.5	273.4	56.2%	63.9%
2027	2,285,503	1,861,031	463.7	276.1	56.3%	64.0%
2028	2,301,046	1,863,066	466.2	276.6	56.2%	63.8%
2029	2,317,481	1,867,091	468.9	277.4	56.4%	64.0%
2030	2,328,667	1,871,556	470.4	278.2	56.5%	64.0%
2031	2,347,896	1,876,179	473.6	279.1	56.6%	64.1%
2032	2,372,775	1,880,236	477.9	279.9	56.5%	63.9%
2033	2,395,795	1,884,854	482.1	280.8	56.7%	64.0%
2034	2,420,143	1,888,897	486.7	281.6	56.8%	64.0%
2035	2,442,083	1,893,375	490.8	282.5	56.8%	64.0%
2036	2,460,336	1,898,249	494.2	283.5	56.7%	63.8%
2037	2,484,286	1,902,702	498.7	284.4	56.9%	64.0%
2038	2,505,191	1,907,552	502.6	285.4	56.9%	63.9%
2039	2,525,724	1,912,320	506.4	286.3	56.9%	63.9%
2040	2,542,976	1,917,144	509.6	287.3	56.8%	63.7%
2041	2,561,009	1,922,446	513.0	288.4	57.0%	63.9%
2042	2,578,209	1,927,690	516.2	289.4	57.0%	63.8%
2043	2,591,846	1,932,939	518.8	290.5	57.0%	63.8%
2044	2,603,815	1,938,625	521.1	291.6	56.9%	63.6%
Average Annual Growth Rates						
Previous 10 Years	-1.02%	5.32%	-2.34%	7.76%	1.32%	1.02%
Previous 5 Years	-0.73%	11.40%	-0.19%	17.32%	-0.60%	-0.79%
Next 5 Years	1.23%	2.84%	-0.73%	1.13%	2.03%	2.05%
Next 10 Years	1.05%	1.53%	0.01%	0.72%	1.07%	1.02%
Next 20 Years	0.89%	0.89%	0.35%	0.53%	0.54%	0.48%

[63] The coincident peak demand referenced in Table 3.2(a) represents the Rural and Direct Serve demand at the time of Big Rivers' native system peak.

3.3 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 3.3(a)[64]

Total System NCP

Total System NCP (kW)					
Year	Total Annual Big Rivers' CP	[redacted]	Total Annual Big Rivers' CP Less Nucor Served by Solar	Non-Member Sales	Total NCP
2020	582,483		582,483	349,600	932,083
2021	606,235		606,235	345,000	951,235
2022	703,135		703,135	508,600	1,211,735
2023	733,105		733,105	250,100	983,205
2024	766,942		766,942	252,400	1,019,342
2025	740,587			251,000	991,587
2026	752,420			252,000	1,004,420
2027	758,388			218,200	976,588
2028	761,496			100,000	861,496
2029	765,068			100,000	865,068
2030	767,538			50,000	817,538
2031	771,684			50,000	821,684
2032	776,863			50,000	792,883
2033	782,200			50,000	797,154
2034	787,737			50,000	801,763
2035	792,847			50,000	805,856
2036	797,262			50,000	809,169
2037	802,800			50,000	813,672
2038	807,791			50,000	817,533
2039	812,713			50,000	821,326
2040	816,994			0	774,468
2041	821,541			0	777,768
2042	825,936			0	780,918
2043	829,639			0	783,366
2044	833,133			0	785,519

[64] KYMEA is modeled as a call option in the model, with the optimized energy and capacity obligations reported as reductions in Wilson's energy and capacity. Note that "Total Annual Big Rivers' CP Less Nucor Served by Solar" is the Big Rivers Coincident Peak that is included in the IRP Analysis and shown in Figure 6.6(b).

3.4 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. The following Table 3.4(a) provides the total system energy requirements.

Table 3.4(a)[65]

Total System Energy Summary

Big Rivers Total System Energy Summary (MWh)										
Year	Rural Requirements	Rural Own Use	Distribution Losses	Total Rural Requirements	Direct Serve	Aux. Sales	Transmission Losses	[redacted]	Non-Member Requirements	Total Energy Requirements
2020	2,061,512	2,814	100,542	2,164,868	824,695	16,944	77,120		1,705,329	4,788,957
2021	2,120,806	3,666	94,909	2,219,380	781,559	18,367	71,125		1,646,667	4,737,098
2022	2,159,727	4,103	105,756	2,269,586	811,577	6,184	72,325		1,710,274	4,869,946
2023	2,008,625	3,893	85,141	2,097,660	1,167,083	833	78,103		1,670,691	5,014,369
2024	2,087,185	3,836	88,764	2,179,785	1,623,201	935	93,173		1,664,068	5,561,162
2025	**2,138,920**	**3,997**	**95,343**	**2,238,259**	**1,785,062**	**935**	**100,594**		**1,336,521**	**5,461,371**
2026	**2,166,930**	**4,023**	**96,577**	**2,267,529**	**1,842,767**	**935**	**102,768**		**1,372,451**	**5,586,450**
2027	**2,187,533**	**4,047**	**93,924**	**2,285,503**	**1,861,031**	**935**	**103,674**		**876,000**	**5,127,143**
2028	**2,202,414**	**4,069**	**94,562**	**2,301,046**	**1,863,066**	**935**	**104,114**		**878,400**	**5,147,559**
2029	**2,218,153**	**4,090**	**95,238**	**2,317,481**	**1,867,091**	**935**	**104,625**		**619,200**	**4,909,331**
2030	**2,228,858**	**4,109**	**95,700**	**2,328,667**	**1,871,556**	**935**	**105,016**		**438,000**	**4,744,175**
2031	**2,247,281**	**4,126**	**96,489**	**2,347,896**	**1,876,179**	**935**	**105,613**		**438,000**	**4,768,623**
2032	**2,271,125**	**4,142**	**97,508**	**2,372,775**	**1,880,236**	**935**	**106,336**		**439,200**	**4,715,222**
2033	**2,293,186**	**4,157**	**98,452**	**2,395,795**	**1,884,854**	**935**	**107,027**		**438,000**	**4,740,963**
2034	**2,316,523**	**4,171**	**99,449**	**2,420,143**	**1,888,897**	**935**	**107,736**		**438,000**	**4,768,888**
2035	**2,337,551**	**4,184**	**100,347**	**2,442,083**	**1,893,375**	**935**	**108,397**		**438,000**	**4,794,590**
2036	**2,355,044**	**4,197**	**101,095**	**2,460,336**	**1,898,249**	**935**	**108,975**		**439,200**	**4,817,982**
2037	**2,378,002**	**4,209**	**102,075**	**2,484,286**	**1,902,702**	**935**	**109,685**		**438,000**	**4,844,558**
2038	**2,398,041**	**4,221**	**102,929**	**2,505,191**	**1,907,552**	**935**	**110,329**		**438,000**	**4,869,365**
2039	**2,417,725**	**4,232**	**103,768**	**2,525,724**	**1,912,320**	**935**	**110,961**		**181,200**	**4,636,906**
2040	**2,434,260**	**4,242**	**104,473**	**2,542,976**	**1,917,144**	**935**	**111,513**			**4,476,910**
2041	**2,451,546**	**4,253**	**105,209**	**2,561,009**	**1,922,446**	**935**	**112,096**			**4,499,090**
2042	**2,468,033**	**4,264**	**105,912**	**2,578,209**	**1,927,690**	**935**	**112,657**			**4,520,467**
2043	**2,481,102**	**4,275**	**106,469**	**2,591,846**	**1,932,939**	**935**	**113,129**			**4,538,112**
2044	**2,492,571**	**4,287**	**106,957**	**2,603,815**	**1,938,625**	**935**	**113,571**			**4,554,448**

[65] KYMEA is modeled as a call option in the model, with the optimized energy and capacity obligations reported as reductions in Wilson's energy and capacity

3.5 Class Forecasts

Consistent with Commission regulation, this IRP includes historical and forecasted information regarding loads, disaggregated by customer class where available. This information is described in greater detail in Appendix A, particularly at Section 3.

3.6 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 Section 6 of Appendix A.

3.7 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 estimated equations along with forecasted values for economic, demographic, and weather variables.

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 peak coincident to the Big Rivers system, the distribution cooperative's Rural Member 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 they then use to calculate the peak demand forecasts for each of the three Member systems or Member CP.

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.

3.8 Model Development

Various economic and demographic variables are used in the econometric models developed for the 2025 load forecast. The key economic and demographic assumptions for these variables are listed below.

- Real residential electricity prices are projected [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 2.6% 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 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.

Section 8.3 of Appendix A, Long-Term Load Forecast Report, describes a research paper produced by Lawrence Berkeley National Laboratory showing no significant performance advantages in forecasting accuracy to employing Statistically Adjusted End-Use (SAE) models versus econometric methods.

Chapter 4

DEMAND-SIDE MANAGEMENT



4. DEMAND-SIDE MANAGEMENT[66]

4.1 Demand-Side Management ("DSM") Introduction

The Demand-Side Management Potential Study, Appendix B, examines the potential to reduce electric consumption and peak demand through the implementation of demand side management technologies and practices in residential and non-residential facilities. DSM potential studies are important and helpful tools for identifying those DSM measures that are the most cost-effective and have the most electricity savings potential. The study assessed energy efficiency and demand response and estimates technical potential, economic potential, and achievable potential throughout Big Rivers Members' service territories over fifteen years, from 2027 through 2041. Results from three program potential scenarios are also presented to estimate the portion of the achievable potential that could be attained given specific funding levels for Big Rivers DSM programs.

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 DSM study evaluates potential energy and demand savings relative to rural system sales and excludes direct-serve customers from the analysis. The results of this study provide detailed information

[66] Responsive to 807 KAR 5:058, Section 5(4) and Section 7(g).

on energy efficiency measures that are cost-effective and have potential kWh and kW savings. The data referenced in this report was the best available at the time this analysis was developed. As building and appliance codes and energy efficiency standards change, and as energy prices fluctuate, additional opportunities for energy efficiency may occur while current practices may become outdated. Actual energy and demand savings will depend upon the level and degree of voluntary member system participation in DSM programs.

4.1.1 Study Objectives

The study had five primary objectives:

1. Develop databases of energy efficiency and demand response measures in the residential and non-residential sectors. The measure databases reflect current industry knowledge of energy efficiency and demand response measures, account for known codes and standards, and align with the market and demographics of Big Rivers Members' customers.

2. Evaluate the electric DSM technical potential savings in Big Rivers Members' territories.

3. Determine the economic potential savings using the Total Resource Cost ("TRC") test benefit-cost ratio for potential electric energy efficiency measures.

4. Evaluate the potential for achievable savings through DSM programs over a fifteen-year horizon (2027-2041).

5. Estimate the total savings over a fifteen-year period from the delivery of a portfolio of programs based on three specific funding scenarios: a $1.0 million annual incentive budget, a $3.0 million annual incentive budget and a $5.0 million annual incentive budget. 50% of the total funding was applied to energy efficiency, and 50% was applied to demand response, such that the portfolio of energy efficiency programs and the portfolio of demand response programs were each analyzed based on three funding scenarios: a $0.5 million annual incentive budget, a $1.5 million annual incentive budget and a $2.5 million annual incentive budget.

4.1.2 Description of the Four Types of Potential Estimated

The scope of this study distinguishes four types of potential: (1) technical, (2) economic, (3) achievable, and (4) program.

1. **Technical Potential** is the theoretical maximum amount of energy use that could be displaced by efficiency, disregarding all non-engineering constraints such as cost-effectiveness and the willingness of end users to adopt efficiency measures. Technical potential is constrained only by factors such as technical feasibility and applicability of measures.

2. **Economic Potential** refers to the subset of the technical potential that is economically cost-effective as compared to conventional supply-side energy resources. Economic potential follows the same adoption rates as technical potential. Like technical potential, the economic scenario ignores market barriers to ensuring actual implementation of efficiency. Finally, economic potential only considers the costs of efficiency measures themselves, ignoring any programmatic costs (e.g., marketing, analysis, administration) that would be necessary to capture them.[67]
3. **Achievable Potential** is the amount of energy use that efficiency can realistically be expected to displace, assuming the most aggressive program scenario possible (e.g., providing end users with payments for the entire incremental cost of more efficient equipment). Achievable potential considers real-world barriers to encouraging end users to adopt efficiency measures, the non-measure costs of delivering programs (for administration, marketing, tracking systems, and monitoring and evaluation), and the capability of programs and administrators to boost program activity over time.[68]
4. **Program Potential** is the amount of potential that can be achieved given specific funding levels and program designs.

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[67] See National Action Plan for Energy Efficiency, *Guide for Conducting Energy Efficiency Potential Studies* at 2-4 (Nov. 2007) available at https://www.epa.gov/sites/default/files/2015-08/documents/potential_guide.pdf.

[68] *Id.*

4.1.3 Summary of Energy Efficiency Potential

Figure 4.1.3(a) provides the technical, economic, achievable and program potential (three funding scenarios) across all sectors in the Big Rivers service territory. The economic potential is approximately 23% of forecasted sales by 2041. The portfolio of energy efficiency programs, including residential and non-residential programs, was analyzed based on three funding scenarios: a $2.5 million annual incentive budget, a $1.5 million annual incentive budget and a $0.5 million annual incentive budget. The program potential at the $0.5 million incentive scenario is approximately 1% of forecasted sales by 2041.

Figure 4.1.3(a)
Electric Efficiency potential Savings Summary

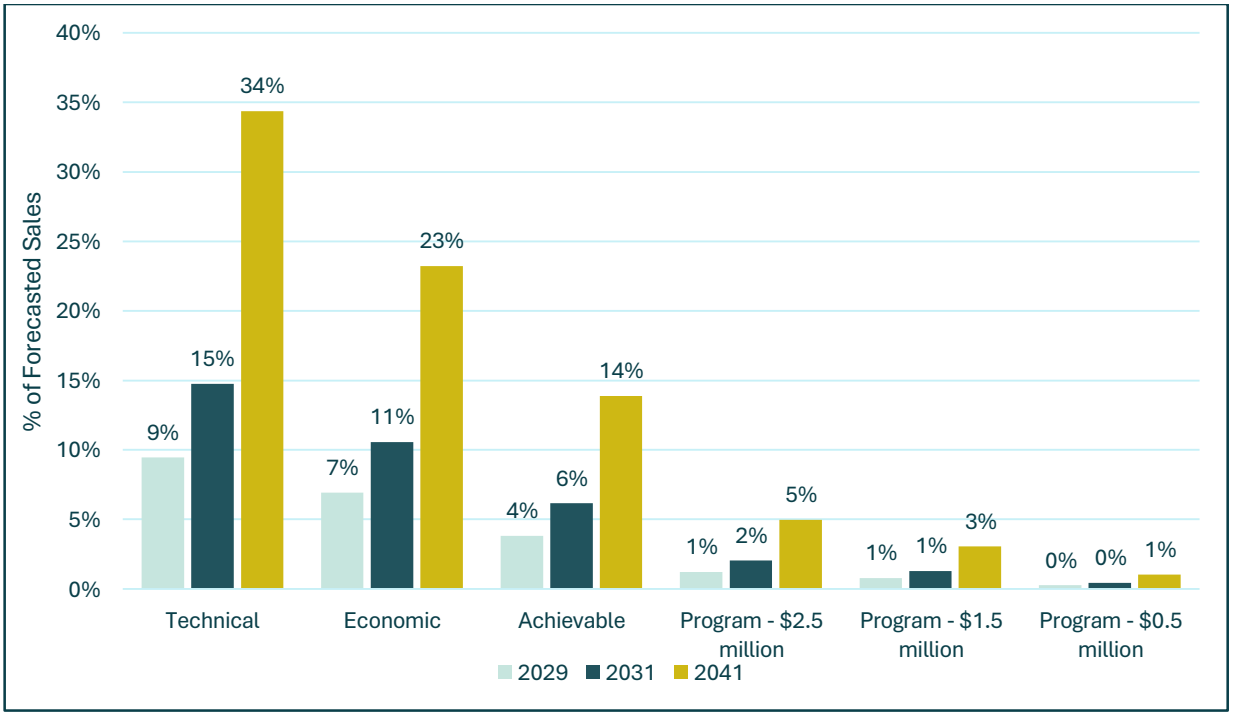


Table 4.1.3(a) provides the 15-year energy, summer demand, and winter demand potential

Table 4.1.3(a)

15-Year Cumulative Summary Results for Energy and Demand

Potential	MWh	Summer MW	Winter MW
Technical	792,672	188.7	131.2
Economic	535,956	106.4	107.8
Achievable	320,328	54.6	56.9
Program - $2.5 million	114,239	23.7	21.7
Program - $1.5 million	70,317	14.3	11.8
Program - $0.5 million	23,753	4.5	3.7

4.1.4 Summary of Demand Response Potential

Similar to the energy efficiency analysis, achievable potential for demand response was calculated based on estimates of the amount of demand response that could be realistically achieved over the study period. Program potential was then considered at three different funding scenarios: a $2.5 million scenario, a $1.5 million scenario, and a $0.5 million scenario. Summer demand potential is shown in Figure 4.1.4(a) in 2027, 2031, and 2041. Table shows the summer and winter demand potential in 2041.

Figure 4.1.4(a)

Demand Response Potential Savings Summary

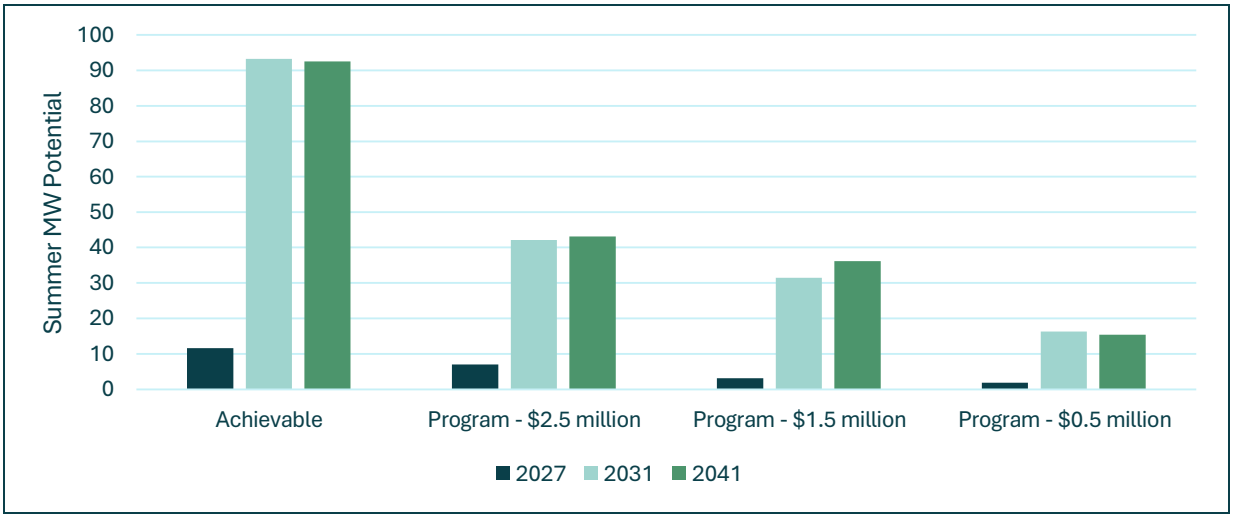


Table 4.1.4(a)

Summary Results For Cumulative Demand Response in Final Year of Study

Potential	Summer MW	Winter MW
Achievable	92.6	82.6
Program - $2.5 million	43.1	43.5
Program - $1.5 million	36.1	32.8
Program - $0.5 million	15.4	16.0

4.2 Methodology

This chapter thoroughly describes the analytical approach utilized to develop the energy efficiency potential study for Big Rivers. The main objectives of the study were to estimate the technical, economic, maximum, and realistic achievable potential savings from energy efficiency and demand response (see Section 4.6, Demand Response Methodology, for details); and to quantify these estimates of potential in terms of MWh and MW savings, for each level of energy

efficiency potential. This document describes the general steps and methods that were used at each stage of the analytical process necessary to produce the various estimates of energy efficiency potential. GDS did not examine delivery approaches for energy efficiency programs as this task was not included in the scope of work for this study.

Energy efficiency potential studies involve several analytical steps to produce estimates of each type of energy efficiency potential: technical, economic, and achievable. This study utilizes benefit/cost screening tools for the residential and non-residential sectors to assess the cost effectiveness of energy efficiency measures. These cost effectiveness screening tools are Excel-based models that integrate technology-specific impacts and costs, customer characteristics, utility avoided cost forecasts and more. Excel was used as the modeling platform to provide transparency to the estimation process and allow for simple customization based on Big Rivers' unique characteristics and the availability of specific model input data. The major analytical steps and an overview of the potential savings are summarized below, and specific changes in methodology from one sector to another have been noted throughout this section.

4.2.1 Overview of Approach

For the residential sector, GDS took a bottom-up approach to the modeling, whereby measure-level estimates of costs, savings, and useful lives were used as the basis for developing the technical, economic, and achievable potential estimates. The measure data was used to build up the technical potential, by

applying the data to each relevant market segment. The measure data allowed for benefit-cost screening to assess economic potential, which was in turn used as the basis for achievable potential, which took into consideration incentives and estimates of annual adoption rates.

For the commercial and industrial sectors, GDS took a bottom-up modeling approach to first estimate measure-level savings and costs as well as cost-effectiveness then applied cost-effective measure savings to all applicable shares of energy load. Disaggregated forecast data served as the foundation for the development of the energy efficiency potential estimates. The disaggregated forecast was developed using regional data from the Energy Information Administration's ("EIA") Annual Energy Outlook ("AEO").

4.2.2 Market Characterization

The initial step in the analysis was to gather a clear understanding of the current market segments in the Big Rivers service area. The GDS team coordinated with Big Rivers to gather utility sales and customer data and existing market research to define appropriate market sectors and market segments. This information served as the basis for completing a forecast disaggregation and market characterization of both the residential and non-residential sectors.

In the commercial and industrial sectors, disaggregated forecast data provides the foundation for the development of energy efficiency potential estimates. GDS disaggregated the commercial sector sales into building type

using data from the US EIA 2022 Annual Energy Outlook data for the East South-Central Census region. For the industrial sector, the baseline electric forecasts were disaggregated by industry type using estimates from EIA Manufacturing Energy Consumption Survey ("MECS") for the same region.

GDS further disaggregated sales for each of the segments into end uses. For commercial segments, GDS again primarily used EIA data for the East South-Central Census region. For the industrial sector, the analysis relied on the EIA's MECS to disaggregate industry-specific estimates of electric consumption into end uses.

- ***Residential.*** The residential forecast was broken out by housing type and construction vintage (new construction vs. existing homes).
- ***Commercial.*** Typically based on major EIA business types: assembly, retail, warehouse, food sales, office, lodging, health, food service, education, and miscellaneous.
- ***Industrial.*** As determined by actual load consumption shares and major industry types as defined by EIA's MECS data.

Within the residential, commercial, and industrial market segments, the sector level disaggregated forecasts were further segmented by the major end uses shown in Table 4.2.2(a).

TABLE 4.2.2(a)

ELECTRIC END USE LOADS

Residential	Non-residential
Refrigerator	Behavioral
Clothes Washer	Compressed Air
Dishwasher	Cooking
Dehumidifier	Cooling
Freezer	Exterior Lighting
Heating	Heating
Cooling	Water Heating
Lighting	Interior Lighting
Pool	Miscellaneous
Plug Load	Motors
HVAC Shell	Office Loads
Water Heating	Refrigeration
Cross-Cutting	Ventilation
	Whole Building
	Whole Building HVAC
	Whole Building NC
	Industrial Compressed Air
	Industrial HVAC
	Industrial Interior Lighting
	Industrial Motors
	Industrial Process Heat
	Industrial Process Refrigeration
	Industrial Process Other
	Industrial Whole Building
	Industrial Water & Wastewater
	Agriculture Motors
	Agriculture Refrigeration
	Agriculture Interior Lighting
	Agriculture Ventilation
	Agriculture HVAC

4.2.3 Measure Characterization

The energy efficiency measures included in this study are currently commercially available as well as emerging technologies. The commercially available measures are of the most immediate interest to Big Rivers. These measure lists were then reviewed, discussed, and updated as necessary. A complete listing

of the energy efficiency measures included in this study is provided in the Appendices of this report.

In addition, this study includes measures that could be relatively easily substituted for, or applied to, existing technologies on a retrofit or replace-on-burnout basis. Replace-on-burnout applies to equipment replacements that are normally made in the market when a piece of equipment is at the end of its useful life. A retrofit measure is eligible to be replaced at any time in the life of the equipment or building. Replace-on-burnout measures are generally characterized by incremental measure costs and savings (e.g. the costs and savings of a high-efficiency versus standard efficiency air conditioner); whereas retrofit measures are generally characterized by full costs and savings (e.g. the full costs and savings associated with adding ceiling insulation into an existing attic). For new construction, energy efficiency measures can be implemented when each new home or building is constructed, thus the rate of availability is a direct function of the rate of new construction.

In total, GDS analyzed 241 measure types for Big Rivers. Many measures required multiple permutations for different applications, such as different building types, efficiency levels, and replacement options. GDS developed a total of 1,722 measure permutations for this study. Table 4.2.3(a) provides a breakdown of the sector-level number of measures and permutations.

Table 4.2.3(a)

Measure Counts by Sector

Sector	# of Measures	Total Permutations
Residential	86	424
C/I	155	1,298
Total	241	1,722

4.2.4 Assumptions and Sources

A significant amount of data is needed to estimate the kWh and kW savings potential for individual energy efficiency and demand response measures or programs across the entire existing residential and non-residential sectors for Big Rivers. GDS used Kentucky specific data wherever it was available and up to date. Considerable effort was expended to identify, review, and document all available data sources.

This review has allowed the development of reasonable and supportable assumptions regarding measure lives; measure installed incremental or full costs (as appropriate); and electric savings and saturations for each energy efficiency measure included in the final list of measures in this study.

Costs and savings for new construction and replace-on-burnout measures are calculated as the incremental difference between the code minimum equipment and the energy efficiency measure. This approach is utilized because the consumer must select an efficiency level that is at least the code of the

minimum equipment. The incremental cost is calculated as the difference between the cost of high efficiency and standard (code compliant) equipment.

However, for retrofit measures, the measure cost is considered the "full" cost of the measure, as the baseline scenario assumes the consumer would do nothing. In general, the savings for retrofit measures are calculated as the difference between the energy use of the removed equipment and the energy use of the new high efficiency equipment (until the removed equipment would have reached the end of its useful life). For measures like insulation, the savings are calculated based on the consumption before and after the installation of improved insulation levels.

Measure Savings: GDS utilized several sources including the Illinois TRM to inform calculations supporting estimates of annual measure savings as a percentage of base equipment usage. Other sources used include:

- Mid-Atlantic TRM, Maine TRM, Minnesota TRM, and other existing deemed savings databases
- Secondary sources such as the American Council for an Energy-Efficient Economy ("ACEEE"), Department of Energy ("DOE"), EIA, ENERGY STAR©, and other technical potential studies.

Measure Costs: Measure costs represent either incremental or full costs. These costs typically include the incremental cost of measure installation, when

appropriate based on the measure definition. For purposes of this study, nominal measure costs held constant over time.

GDS obtained measure cost estimates from a variety of sources, starting with the 2021 Ill TRM. Other sources leveraged include:

- Mid-Atlantic TRM, Indiana TRM, Maine TRM, Minnesota TRM, and other existing deemed savings databases
- Secondary sources such as the ACEEE, ENERGY STAR, National Renewable Energy Lab ("NREL"), California Database for Energy Efficient Resources ("DEER") database, Northeast Energy Efficiency Partnership ("NEEP") Incremental Cost Study, and other technical potential studies

Measure Life: Measure life represents the number of years that energy using equipment is expected to operate. GDS obtained measure life estimates from the 2021 Ill TRM, and used the following other data sources:

- TRMs in other states
- Manufacturer data
- Savings calculators and life-cycle cost analyses
- The California DEER database
- Other consultant research or technical reports

Building/Equipment Saturation Data: To assess the amount of electric energy efficiency savings still available, estimates of the current saturation of baseline equipment and energy efficiency measures, or for the non-residential sector, the amount of energy use that is associated with a specific end-use (such as Heating, Ventilation, and Air Conditioning ("HVAC")) and percent of that energy use that is associated with energy efficient equipment are necessary. Up-to-date measure saturation data was primarily obtained from the following recent studies:

- 2025 Big Rivers End-Use Saturation Surveys
- 2020 EIA Residential Energy Consumption Survey (RECS)
- Energy Star Unit Shipment Data
- 2022 EIA Annual Energy Outlook
- EIA Baseline Energy Calculator
- 2023 Pennsylvania Baseline Study

4.2.5 Energy Efficiency Potential

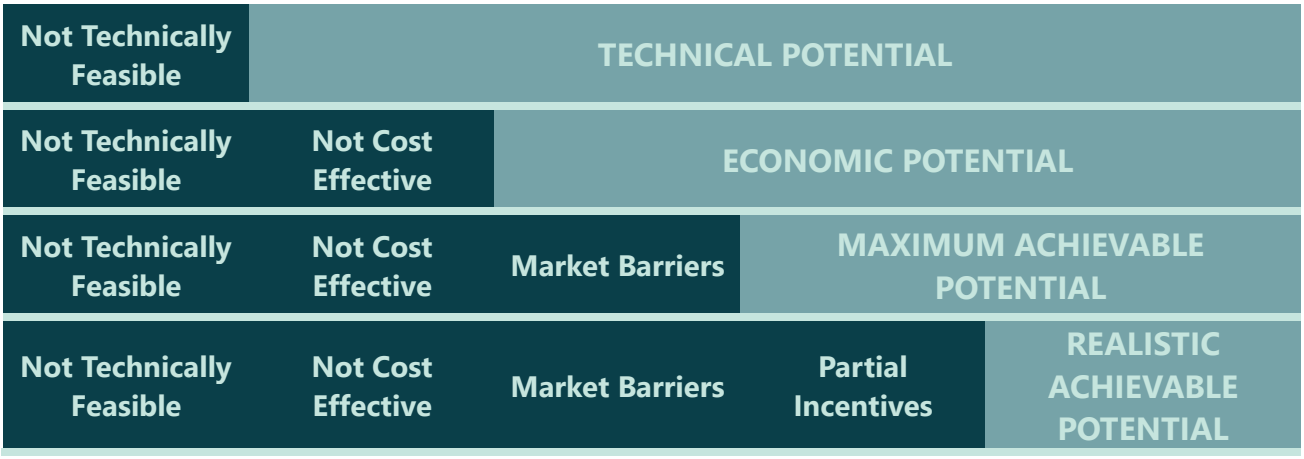
This section reviews the types of potential analyzed in this report, as well as some key methodological considerations in the development of technical, economic, and achievable potential.

The first two types of potential, technical and economic, provide a theoretical upper bound for energy savings from energy efficiency measures. Still, even the best-designed portfolio of programs is unlikely to capture 100% of the

technical or economic potential. Therefore, achievable potential attempts to estimate what savings can be realistically achieved through market interventions, when they can be captured, and how much it would cost to do so. Figure 4.2.5(a) illustrates the types of energy efficiency potential considered in this analysis.

FIGURE 4.2.5(a)

Type of Energy Efficiency Potential[69]



4.2.6 Technical Potential

Technical potential is the theoretical maximum amount of energy use that could be displaced by efficiency, disregarding all non-engineering constraints such as cost-effectiveness and the willingness of end users to adopt the efficiency measures. Technical potential is only constrained by factors such as technical feasibility and applicability of measures. Under technical potential, GDS assumed that 100% of new construction and market opportunity measures are adopted as those opportunities become available (e.g., as new buildings are constructed, they

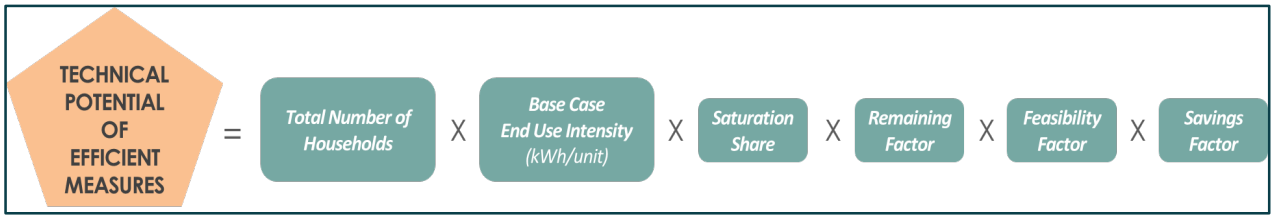
[69] Adapted from U.S. Environmental Protection Agency, *Guide to Resource Planning with Energy Efficiency*" (Nov. 2007), Figure 2-1. Modified to depict the additional levels of achievable and program potential included in this study.

immediately adopt efficiency measures, or as existing measures reach the end of their useful life). For retrofit measures, implementation was assumed to be resource constrained and that it was not possible to install all retrofit measures all at once. Rather, retrofit opportunities were assumed to be replaced incrementally until 100% of stock was converted to the efficient measure over a period of no more than 20 years.

The core equation used in the residential sector energy efficiency technical potential analysis for each individual efficiency measure is shown in Equation 4.2.6 below. The Commercial and Industrial ("C&I") sector employs a similar analytical approach

Equation 4.2.6

Core Equation for Residential Sector Technical Potential.



Base Case Equipment End-Use Intensity = the electricity used per customer per year by each base-case technology in each market segment. In other words, the base case equipment end-use intensity is the consumption of the electrical energy using equipment that the efficient technology replaces or affects.

Saturation Share = the fraction of the end-use electrical energy that is applicable to the efficient technology in each market segment. For example, for residential water heating, the saturation share would be the fraction of all residential electric customers that have electric water heating in their household.

Remaining Factor = the fraction of equipment that is not considered to already be energy efficient. To extend the example above, the fraction of electric water heaters that is not already energy efficient.

Feasibility Factor = (also functions as the applicability factor) the fraction of the applicable units that is technically feasible for conversion to the most efficient available technology from an engineering perspective (e.g., it may not be possible to install heat pump water heaters in all homes because of space limitations).

Savings Factor = the percentage reduction in electricity consumption resulting from the application of the efficient technology.

Competing Measures & Interactive Effects Adjustments. GDS prevents double-counting of savings, and accounts for competing measures and interactive savings effects, through three primary adjustment factors:

Baseline Saturation Adjustment. Competing measure shares are factored into the baseline saturation estimates. For example, nearly all homes can receive insulation. To account for this, GDS' analysis used multiple measure permutations that account for varying impacts of different heating/cooling combinations and baseline saturations were applied to reflect the proportions of households with each heating/cooling combination.

Applicability Factor Adjustment. Combined measures into measure groups, where total applicability factor across measures is set to 100%. For example, homes cannot receive a programmable thermostat, connected thermostat, and smart thermostat. In general, the models assign the measure with the most savings the greatest applicability factor in the measure group, with competing measures picking up any remaining share.

Interactive Savings Adjustment. As savings are introduced from select measures, the per-unit savings from other measures need to be adjusted (downward) to avoid over-counting. The analysis typically prioritizes market opportunity equipment measures (versus retrofit measures that can be installed at any time). For example, the savings from a smart thermostat and other HVAC related weatherization measures like insulation and sealing are adjusted down to reflect the efficiency gains of installing an efficient air source heat pump.

4.2.7 Achievable Potential

Achievable potential is the amount of energy that can realistically be saved given various market barriers. Achievable potential considers real-world barriers to encouraging end users to adopt efficiency measures; the non-measure costs of delivering programs (for administration, marketing, analysis, and EM&V);[70] and the capability of programs and administrators to boost program activity over time. Barriers include financial, customer awareness and willingness-to-participate ("WTP") in programs, technical constraints, and other barriers the "program intervention" is modeled to overcome. Additional considerations include political and/or regulatory constraints.

4.2.8 Market Adoption Rates

GDS assessed achievable potential on a measure-by-measure basis. In addition to accounting for the natural replacement cycle of equipment in the achievable potential scenario, GDS estimated measure specific maximum adoption rates that reflect the presence of possible market barriers and associated difficulties in achieving the 100% market adoption assumed in the technical and economic scenarios.

The initial step was to assess the long-term market adoption potential for energy efficiency technologies. Due to the wide variety of measures across multiple end-uses, GDS employed varied measure and end-use-specific ultimate

[70] "EM&V" means evaluation, measurement and verification.

adoption rates versus a singular universal market adoption curve. These long-term market adoption estimates were based on aggregated WTP market research across several recent GDS studies. The WTP research included questions to residential homeowners and non-residential facility managers regarding their perceived willingness to purchase and install energy efficient technologies across various end uses and incentive/payback performance levels. One caveat to this approach is that the WTP adoption score is generally a simple function of incentive levels and/or payback performance.

GDS utilized likelihood and willingness-to-participate data to estimate the long-term market adoption potential for both the maximum and realistic achievable scenarios. Table 4.2.8(a) presents the long-term market adoption rates at varied incentive levels used for the residential sector. Most end-uses are based on the WTP market research.

Table 4.2.8 (a)
Residential Long-Term Market Adoption Rates
at Discrete Incentive Levels

End Use	0% Incentive	50% Incentive	80% Incentive	100% Incentive
Water Heating	39%	54%	64%	77%
HVAC Equipment	28%	46%	59%	77%
HVAC Shell	32%	51%	60%	75%
Appliances	44%	62%	70%	86%

Table 4.2.8 (b) presents the long-term market adoption rates used in the non-residential sector.

Table 4.2.8(b)
Non-Residential Long-Term Market Adoption Rates
at Discrete Payback Intervals

End-Use	10 Year Payback Period	5 Year Payback Period	3 Year Payback Period	1 Year Payback Period	0 Year Payback Period
Lighting	27%	43%	52%	64%	73%
HVAC	24%	38%	50%	60%	66%
Refrigeration	31%	38%	44%	53%	58%
Water Heat	30%	37%	46%	55%	62%

In the maximum achievable potential scenario, incentives were assumed to represent 100% of the measure cost (0-year payback).

4.3 Residential Energy Efficiency Potential

This chapter provides the results for technical, economic, and achievable potential for the residential sector. The chapter breaks down the potential by end use. The results are provided on a five, ten and fifteen-year basis.

Figure 4.3(a) provides the technical, economic, achievable potential results for the 3-year, 5-year, and 15-year timeframes. The cumulative annual 3-year technical potential is 10% of the residential forecasted sales, and the economic potential is 7% of forecasted sales. The cumulative annual 3-year achievable potential is 4% as a percentage of forecasted residential sales. Over the duration of the study timeframe the technical potential rises to 36%, and the economic potential rises to 23% of forecasted sales. The achievable potential rises to 14% of forecasted sales. The gap between economic potential and achievable potential

represents market barriers to prospective program participants, both financial and non-financial, to achieving the full amount of economic potential.

Figure 4.3(a)

Residential Cumulative annual Energy Savings Summary

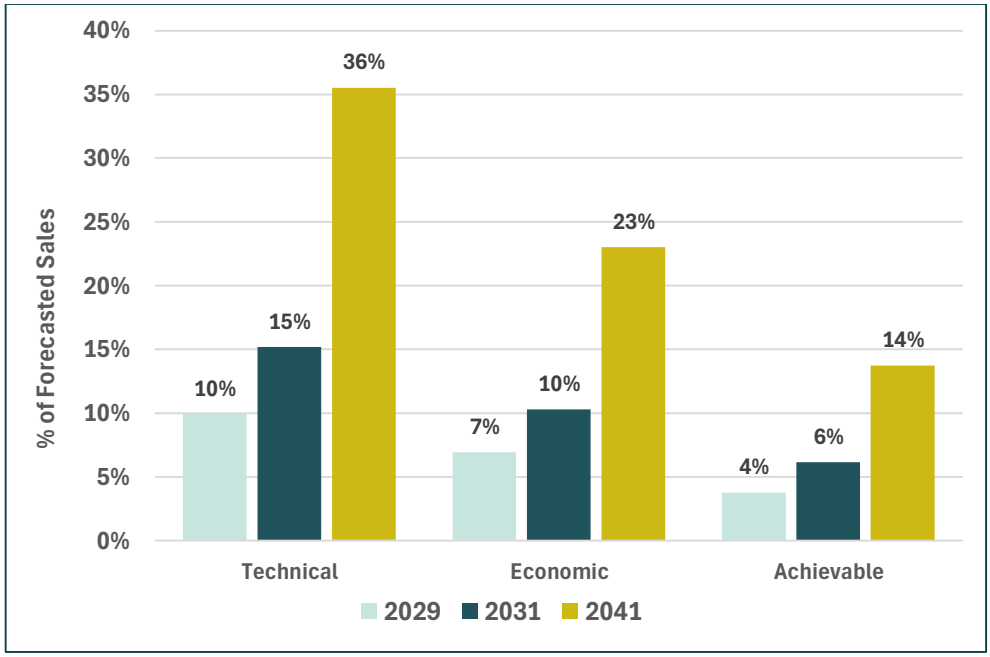


Table 4.3(a) provides the 15-year residential energy, summer demand, and winter demand potential

Table 4.3(a)

15-Year Summary Results for Cumulative Residential Energy and Demand Savings

Potential	MWh	Summer MW	Winter MW
Technical	524,783	144.2	101.4
Economic	339,999	75.8	85.0
Achievable	202,616	42.3	47.4

Table 4.3(b) provides 1-,2-,3-,5-, and 15-year estimates of cumulative annual technical, economic, and achievable potential for energy.

Table 4.3(b)
Residential Cumulative Annual Energy Efficiency Potential Summary

Energy (MWh)	2027	2028	2029	2031	2041
Technical	61,986	101,958	140,967	216,778	524,783
Economic	47,386	73,069	98,107	146,894	339,999
Achievable	13,706	31,325	53,449	87,786	202,616
Energy Savings (as % of Forecast)					
Technical	4%	7%	9%	15%	36%
Economic	3%	5%	7%	10%	23%
Achievable	1%	2%	4%	6%	14%

4.3.1 Technical Potential

Table 4.3.1(a) provides 1-,2-,3-,5-, and 15-year cumulative annual technical potential estimates for energy by end use for Big Rivers

Table 4.3.1(a)
Residential Electric Energy (Cumulative Annual MWh) Technical Potential by End-Use

End Use	2027	2028	2029	2031	2041
Appliances	4,907	9,764	14,569	24,020	55,487
Behavioral	22,826	24,290	25,746	28,634	29,359
HVAC Equipment	7,388	14,711	21,946	36,148	102,872
Lighting	1,636	3,269	4,656	7,304	17,926
Pool/Pump	686	1,370	2,053	3,413	6,720
New Construction	668	1,314	1,919	3,009	6,635
Plug Load	2,542	5,081	7,611	12,651	37,520
Shell	15,258	30,097	44,529	72,209	189,562
Water Heating	6,015	11,939	17,757	29,089	77,806
Cross-Cutting	61	121	182	302	895
Total	**61,986**	**101,958**	**140,967**	**216,778**	**524,783**

Table 4.3.1(b) provides 1-,2-,3-,5-, and 15-year cumulative annual technical potential estimates for summer demand by end use for Big Rivers.

Table 4.3.1(b)
Residential Electric Demand (Cumulative Annual MW)
Technical Potential by End-Use

End Use	2027	2028	2029	2031	2041
Appliances	0.64	1.28	1.91	3.14	7.38
Behavioral	2.61	2.77	2.94	3.27	3.35
HVAC Equipment	4.14	8.24	12.30	20.26	57.74
Lighting	0.15	0.29	0.44	0.72	1.79
Pool/Pump	0.31	0.61	0.92	1.53	2.20
New Construction	0.12	0.23	0.34	0.53	1.17
Plug Load	0.30	0.60	0.90	1.50	4.45
Shell	4.29	8.47	12.53	20.32	53.35
Water Heating	0.90	1.80	2.68	4.43	12.65
Cross-Cutting	0.01	0.01	0.02	0.03	0.10
Total	**13.5**	**24.3**	**35.0**	**55.7**	**144.2**

4.3.2 Economic Potential

Table 4.3.2(a) provides 1-, 2-, 3-, 5-, and 15-year cumulative annual economic potential estimates for energy by end use for Big Rivers.

Table 4.3.2(a)

Residential Electric Energy (Cumulative Annual MWh)

Economic Potential by End-Use

End Use	2027	2028	2029	2031	2041
Appliances	3,233	6,463	9,688	16,121	35,860
Behavioral	22,826	24,290	25,746	28,634	29,359
HVAC Equipment	5,140	10,240	15,285	25,205	72,127
Lighting	1,636	3,269	4,656	7,304	17,926
Pool/Pump	250	499	747	1,239	3,639
New Construction	668	1,314	1,919	3,009	6,635
Plug Load	1,305	2,608	3,907	6,494	19,260
Shell	6,369	12,564	18,588	30,143	79,132
Water Heating	5,899	11,699	17,388	28,442	75,165
Cross-Cutting	61	121	182	302	895
Total	**47,386**	**73,069**	**98,107**	**146,894**	**339,999**

Table 4.3.2(b) provides 1-, 2-, 3-, 5-, and 15-year cumulative annual economic potential estimates for summer demand by end use for Big Rivers

Table 4.3.2(b)

Residential Electric Demand (Cumulative Annual MW)

Economic Potential by End-Use

End Use	2027	2028	2029	2031	2041
Appliances	0.43	0.86	1.29	2.14	4.84
Behavioral	2.61	2.77	2.94	3.27	3.35
HVAC Equipment	1.91	3.82	5.70	9.43	27.31
Lighting	0.15	0.29	0.44	0.72	1.79
Pool/Pump	0.00	0.01	0.01	0.02	0.05
New Construction	0.12	0.23	0.34	0.53	1.17
Plug Load	0.15	0.29	0.44	0.73	2.16
Shell	1.80	3.54	5.24	8.50	22.32
Water Heating	0.91	1.81	2.70	4.46	12.69
Cross-Cutting	0.01	0.01	0.02	0.03	0.10
Total	**8.1**	**13.6**	**19.1**	**29.8**	**75.8**

4.3.3 Achievable Potential

Achievable potential is the amount of energy that can realistically be saved given various market barriers. Achievable potential considers real-world barriers to encouraging end users to adopt efficiency measures; the non-measure costs of delivering programs (for administration, marketing, analysis, and EM&V); and the capability of programs and administrators to boost program activity over time. Therefore, achievable potential is an estimate of how much economic potential can be achieved by program administrators.

Table 4.3.3(a) provides 1-, 2-, 3-, 5-, and 15-yr cumulative annual achievable potential estimates for energy by end use for Big Rivers.**Table 4.3.3(a)**

Residential Electric Energy (Cumulative Annual MWh)

Achievable Potential by End-Use

End Use	2027	2028	2029	2031	2041
Appliances	1,968	3,965	6,012	10,168	23,093
Behavioral	1,722	7,164	16,762	25,964	29,359
HVAC Equipment	2,106	4,257	6,488	11,022	32,854
Lighting	1,174	2,346	3,514	5,659	14,891
Pool/Pump	23	57	111	246	922
New Construction	353	695	1,015	1,591	3,509
Plug Load	819	1,636	2,451	4,074	12,083
Shell	2,991	5,957	8,899	14,707	42,401
Water Heating	2,513	5,170	8,079	14,161	42,928
Cross-Cutting	39	78	117	194	576
Total	**13,706**	**31,325**	**53,449**	**87,786**	**202,616**

4.3.3(b) provides 1-, 2-, 3-, 5-, and 15-yr cumulative annual achievable potential estimates for summer demand by end use for Big Rivers.

Table 4.3.3(b)
Residential Electric Demand (Cumulative Annual MW)
Achievable Potential by End-Use

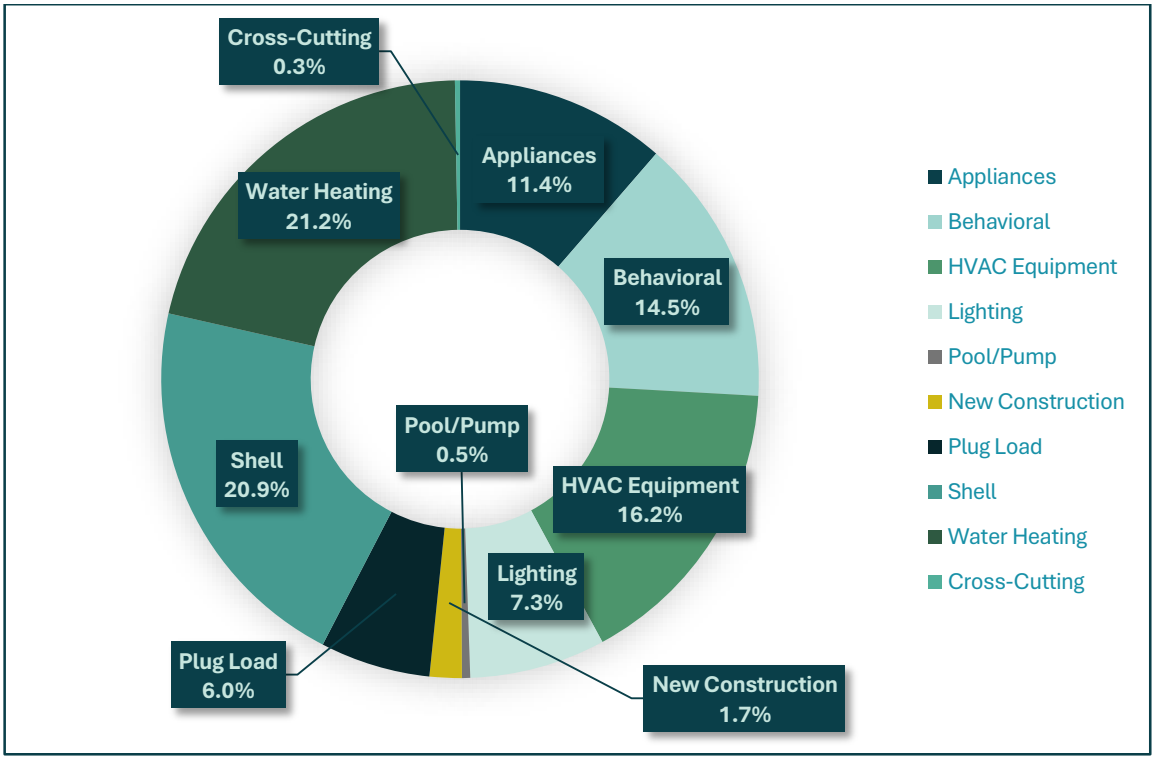
End Use	2027	2028	2029	2031	2041
Appliances	0.27	0.53	0.81	1.37	3.17
Behavioral	0.20	0.82	1.91	2.96	3.35
HVAC Equipment	0.87	1.75	2.65	4.43	13.09
Lighting	0.11	0.21	0.32	0.53	1.52
Pool/Pump	0.00	0.00	0.00	0.01	0.02
New Construction	0.06	0.12	0.18	0.28	0.62
Plug Load	0.09	0.18	0.28	0.46	1.36
Shell	0.86	1.71	2.55	4.21	12.14
Water Heating	0.46	0.92	1.39	2.34	6.92
Cross-Cutting	0.00	0.01	0.01	0.02	0.07
Total	**2.9**	**6.3**	**10.1**	**16.6**	**42.3**

4.3.3(a) provides a graphical representation of the 15-yr cumulative annual achievable potential results by end use.

Figure 4.3.3(a)

Residential Electric Energy (cumulative annual gwh)

achievable potential by end-use



4.4 Non-Residential Energy Efficiency Potential

This chapter provides the results for technical, economic, and achievable potential for the non-residential sector. The chapter breaks down the potential by end use. The results are provided on a five, ten and fifteen-year basis.

Figure 4.4(a) provides the technical, economic, achievable potential results for the 3-year, 5-year, and 15-year timeframes. The cumulative annual 3-year technical potential is 9% of the non-residential forecasted sales, and the economic potential is 7% of forecasted sales. The cumulative annual 3-year achievable potential is 4% as a percentage of forecasted non-residential sales. Over the duration of the study timeframe the technical potential rises to 32%, and the economic potential rises to 24% of forecasted sales. The achievable potential rises to 14% of forecasted sales. The gap between economic potential and achievable potential represents market barriers to prospective program participants, both financial and non-financial, to achieving the full amount of economic potential.

Figure 4.4(a)

Non-Residential Cumulative Annual Energy Savings Summary

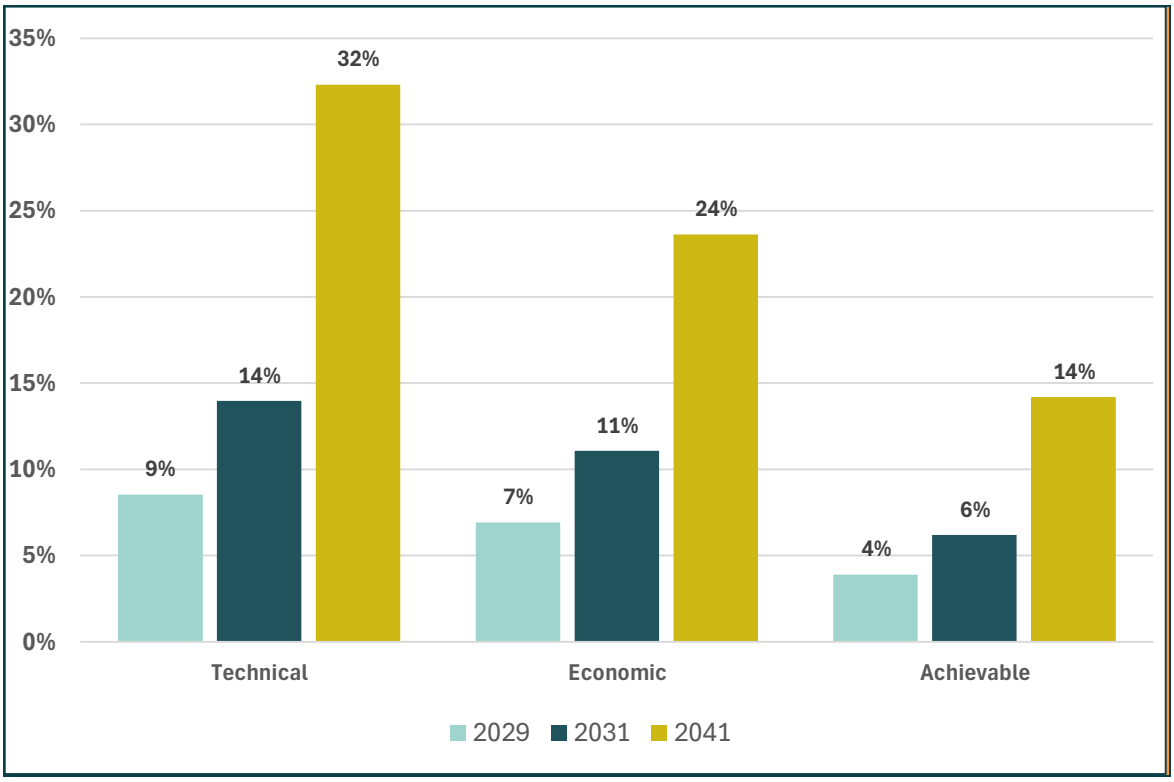


Table 4.4(a) provides the 15-year non-residential energy, summer demand, and winter demand potential

TABLE 4.4(a)

15-Year Summary Results for Non-Residential Energy and Demand Savings

Potential	MWh	Summer MW	Winter MW
Technical	267,889	44.6	29.8
Economic	195,957	30.6	22.7
Achievable	117,712	12.3	9.5

Table 4.4(b) provides 1-, 2-, 3-, 5-, and 15-year estimates of cumulative annual technical, economic, and achievable potential for energy.

Table 4.4(b)

Non-Residential Cumulative Annual Energy Efficiency Potential Summary (MWh)

	2027	2028	2029	2031	2041
Energy (MWh)					
Technical	23,047	45,021	66,602	109,693	267,889
Economic	19,426	37,108	54,006	86,927	195,957
Achievable	10,887	20,904	30,350	48,623	117,712
Energy Savings (as % of Forecast)					
Technical	3%	6%	9%	14%	32%
Economic	3%	5%	7%	11%	24%
Achievable	1%	3%	4%	6%	14%

4.4.1 Technical Potential

Table 4.4.1(a) provides 1-, 2-, 3-, 5-, and 15-year cumulative annual technical potential estimates for energy by end use for Big Rivers.

Table 4.4.1(a)

Non-Residential Electric Energy (Cumulative Annual kWh)

Technical Potential by End-Use

End Use	2027	2028	2029	2031	2041
Behavioral	0	0	0	0	0
Compressed Air	150,125	308,547	471,333	791,656	1,664,380
Cooking	312,268	624,536	936,803	1,561,339	4,033,338
Cooling	2,222,895	4,628,744	7,150,355	12,283,040	29,449,653
Exterior Lighting	775,605	1,442,172	1,992,639	2,774,677	3,376,290
Heating	101,468	202,935	304,403	507,338	1,522,013
Water Heating	218,896	425,361	621,390	990,464	2,477,956
Interior Lighting	3,156,412	6,572,770	10,099,669	16,942,788	33,230,880
Miscellaneous	663,332	1,365,219	2,167,037	4,072,405	12,703,956
Motors	571,962	1,155,583	1,748,409	2,944,290	8,404,326
Office Loads	1,027,104	2,214,972	3,542,320	6,423,537	14,283,444
Refrigeration	2,640,283	5,515,171	8,555,733	14,715,861	27,674,940
Ventilation	544,312	1,064,516	1,545,322	2,347,229	3,518,608
Whole Building	596,500	1,426,121	2,323,499	4,238,982	16,181,691
Whole Building HVAC	2,679,621	6,022,112	9,766,158	18,175,998	63,339,703
Whole Building NC	5,403,077	7,939,172	9,060,329	10,174,546	20,359,952
Industrial Compressed Air	126,819	265,473	410,051	704,871	1,660,257
Industrial HVAC	178,167	368,519	563,783	959,196	2,661,793
Industrial Interior Lighting	562,664	1,149,016	1,709,926	2,657,908	3,985,301
Industrial Motors	498,974	1,033,216	1,582,132	2,695,102	7,440,862
Industrial Process Heat	94,089	199,832	312,343	546,612	1,342,926
Industrial Process Refrigeration	113,401	233,992	357,258	606,175	1,700,995
Industrial Process Other	156,041	321,737	490,744	831,083	1,790,502
Industrial Whole Building	228,678	490,064	804,912	1,575,270	4,516,891
Industrial Water & Wastewater	22,068	47,238	78,819	161,755	547,086
Agriculture Motors	372	756	1,149	1,943	5,366
Agriculture Refrigeration	97	197	299	503	1,388
Agriculture Interior Lighting	1,231	2,532	3,849	6,311	10,973
Agriculture Ventilation	291	582	873	1,455	2,910
Agriculture HVAC	48	96	143	239	551
Total	**23,046,799**	**45,021,179**	**66,601,682**	**109,692,577**	**267,888,932**

4.4.2 Economic Potential

Table 4.4.2 (a) provides 1-, 2-, 3-, 5-, and 15-yr cumulative annual economic potential estimates for energy by end use for Big Rivers.

Table 4.4.2(a)
Non-Residential Electric Energy (Cumulative Annual kWh)
Economic Potential by End-Use

End Use	2027	2028	2029	2031	2041
Behavioral	0	0	0	0	0
Compressed Air	98,327	205,800	318,529	541,407	1,063,818
Cooking	296,233	592,467	888,700	1,481,167	3,840,926
Cooling	1,414,996	2,958,044	4,594,236	7,933,389	16,934,408
Exterior Lighting	775,605	1,442,172	1,992,639	2,774,677	3,376,290
Heating	72,185	144,371	216,556	360,927	1,082,780
Water Heating	197,381	382,330	556,845	882,888	2,262,804
Interior Lighting	3,147,042	6,557,111	10,080,225	16,920,661	33,219,463
Miscellaneous	604,131	1,243,920	1,982,028	3,761,588	11,991,588
Motors	572,117	1,155,910	1,748,920	2,945,182	8,406,421
Office Loads	994,476	2,152,099	3,451,082	6,277,662	14,041,402
Refrigeration	2,148,234	4,476,962	6,935,540	11,926,633	22,484,340
Ventilation	537,633	1,050,543	1,522,289	2,300,665	3,365,961
Whole Building	475,836	1,170,623	1,922,812	3,550,045	16,263,284
Whole Building HVAC	761,049	1,644,435	2,612,273	4,691,830	12,280,027
Whole Building NC	5,403,077	7,939,172	9,060,329	10,174,546	20,359,952
Industrial Compressed Air	126,819	265,473	410,051	704,871	1,660,257
Industrial HVAC	178,167	368,519	563,783	959,196	2,661,793
Industrial Interior Lighting	562,664	1,149,016	1,709,926	2,657,908	3,985,301
Industrial Motors	498,974	1,033,216	1,582,132	2,695,102	7,440,862
Industrial Process Heat	94,089	199,832	312,343	546,612	1,342,926
Industrial Process Refrigeration	113,401	233,992	357,258	606,175	1,700,995
Industrial Process Other	156,041	321,737	490,744	831,083	1,790,502
Industrial Whole Building	173,358	368,829	611,146	1,230,755	3,832,590
Industrial Water & Wastewater	22,068	47,238	78,819	161,755	547,086
Agriculture Motors	372	756	1,149	1,943	5,366
Agriculture Refrigeration	97	197	299	503	1,388
Agriculture Interior Lighting	1,231	2,532	3,849	6,311	10,973
Agriculture Ventilation	291	582	873	1,455	2,910
Agriculture HVAC	48	96	143	239	551
Total	**19,425,942**	**37,107,973**	**54,005,521**	**86,927,176**	**195,956,965**

4.4.3 Achievable Potential

Achievable potential is the amount of energy that can realistically be saved given various market barriers. Achievable potential considers real-world barriers to encouraging end users to adopt efficiency measures; the non-measure costs of delivering programs (for administration, marketing, analysis, and EM&V); and the capability of programs and administrators to boost program activity over time. Therefore, achievable potential is an estimate of how much economic potential can be achieved by program administrators.

Table 4.4.3(a) provides 1-, 2-, 3-, 5-, and 15-yr cumulative annual achievable potential estimates for energy by end use for Big Rivers.

Table 4.4.3(a)

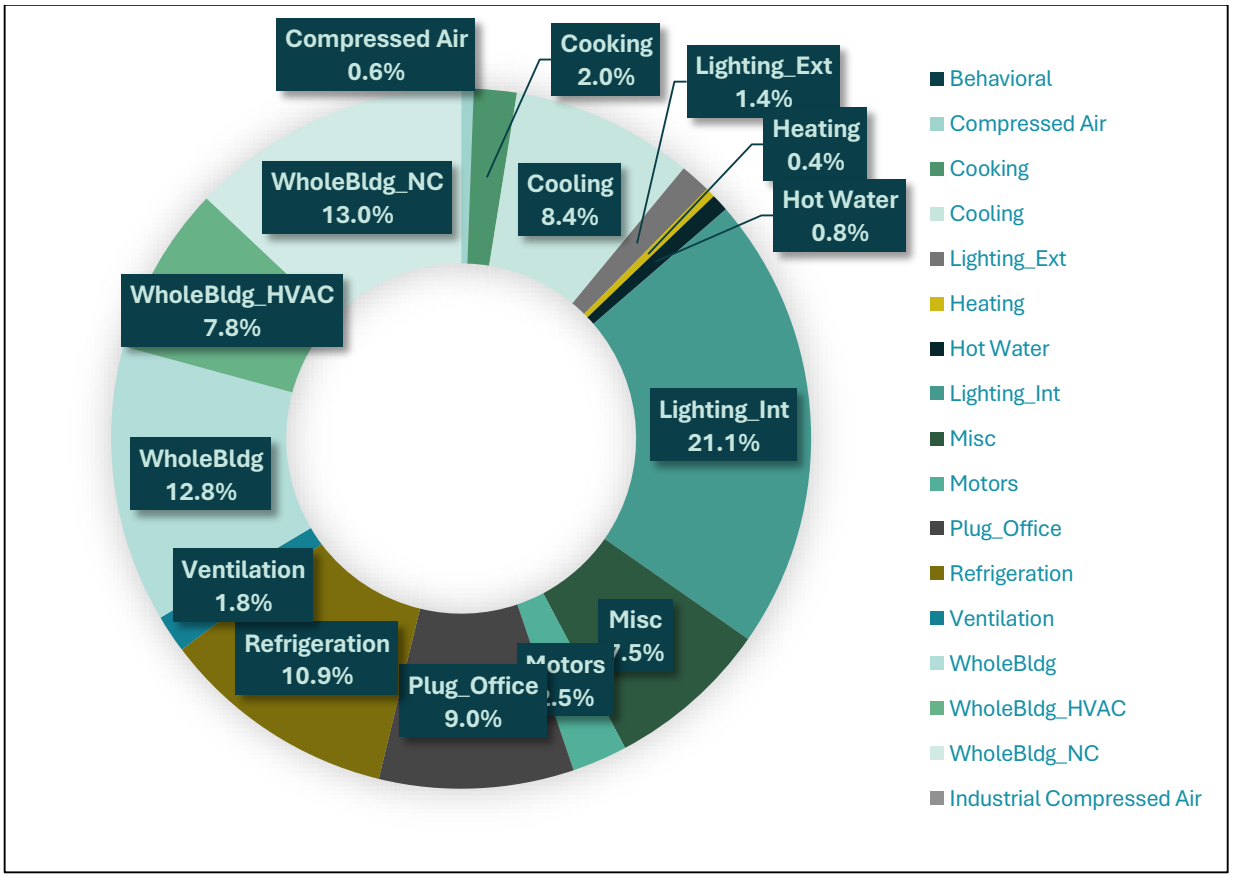
Non-Residential Electric Energy (Cumulative Annual KWh)

Achievable Potential by End-Use

End Use	2027	2028	2029	2031	2041
Behavioral	0	0	0	0	0
Compressed Air	64,694	130,784	196,015	316,876	588,016
Cooking	104,430	220,873	348,059	628,611	2,028,328
Cooling	747,595	1,562,964	2,418,084	4,110,669	8,608,860
Exterior Lighting	374,209	683,240	930,151	1,268,707	1,460,017
Heating	8,432	19,402	33,398	72,086	449,855
Water Heating	49,580	94,746	137,075	221,240	839,480
Interior Lighting	2,258,099	4,561,862	6,833,383	11,088,331	21,555,008
Miscellaneous	290,024	609,268	966,646	1,925,452	7,725,985
Motors	54,357	126,789	217,078	444,674	2,606,066
Office Loads	613,683	1,342,563	2,172,727	4,006,987	9,208,491
Refrigeration	1,192,710	2,458,426	3,749,938	6,211,046	11,175,295
Ventilation	332,468	635,468	902,314	1,318,267	1,793,325
Whole Building	349,843	866,780	1,433,119	2,681,599	13,091,036
Whole Building HVAC	521,945	1,118,362	1,761,264	3,109,056	7,979,132
Whole Building NC	2,966,168	4,473,256	5,181,431	5,923,690	13,277,307
Industrial Compressed Air	46,233	103,455	169,521	321,992	1,006,313
Industrial HVAC	51,718	116,731	193,302	376,940	1,452,950
Industrial Interior Lighting	474,577	921,638	1,312,172	1,908,278	2,570,287
Industrial Motors	147,992	333,738	552,075	1,073,856	4,075,118
Industrial Process Heat	41,686	92,771	150,975	282,109	794,620
Industrial Process Refrigeration	31,361	70,926	117,737	230,920	921,824
Industrial Process Other	43,739	98,807	163,804	319,818	1,119,315
Industrial Whole Building	106,768	228,965	359,442	681,516	2,995,943
Industrial Water & Wastewater	14,042	29,626	46,829	94,547	377,519
Agriculture Motors	95	211	347	672	2,583
Agriculture Refrigeration	25	55	89	167	594
Agriculture Interior Lighting	821	1,647	2,455	3,927	6,655
Agriculture Ventilation	63	141	233	464	1,657
Agriculture HVAC	8	19	31	64	283
Total	**10,887,367**	**20,903,511**	**30,349,693**	**48,622,562**	**117,711,864**

Figure 4.4.3(a) provides a graphical representation of the 15-yr cumulative annual achievable potential results by end use.

Figure 4.4.3(a)
Non-Residential Electric Energy (Cumulative Annual GWh)
Achievable Potential by End-Use



4.5 Energy Efficiency Program Potential

This study estimates potential savings from a portfolio of energy efficiency programs based on specified funding levels, including $0.5 million, $1.5 million, and $2.5 million annual incentive budget scenarios. All program scenarios remain

cost-effective under the TRC test. It is important to note that the program potential results represent a subset of achievable potential and are intended to illustrate what could be attained under specific funding levels. These results are not intended to represent specific future program designs or approved budgets.

Figure 4.5(a) provides a summary of the 15-year program potential (three funding scenarios) in comparison to the technical, economic, and achievable potential in the Big Rivers service territory.

Figure 4.5(a)

Electric Efficiency Potential Savings Summary

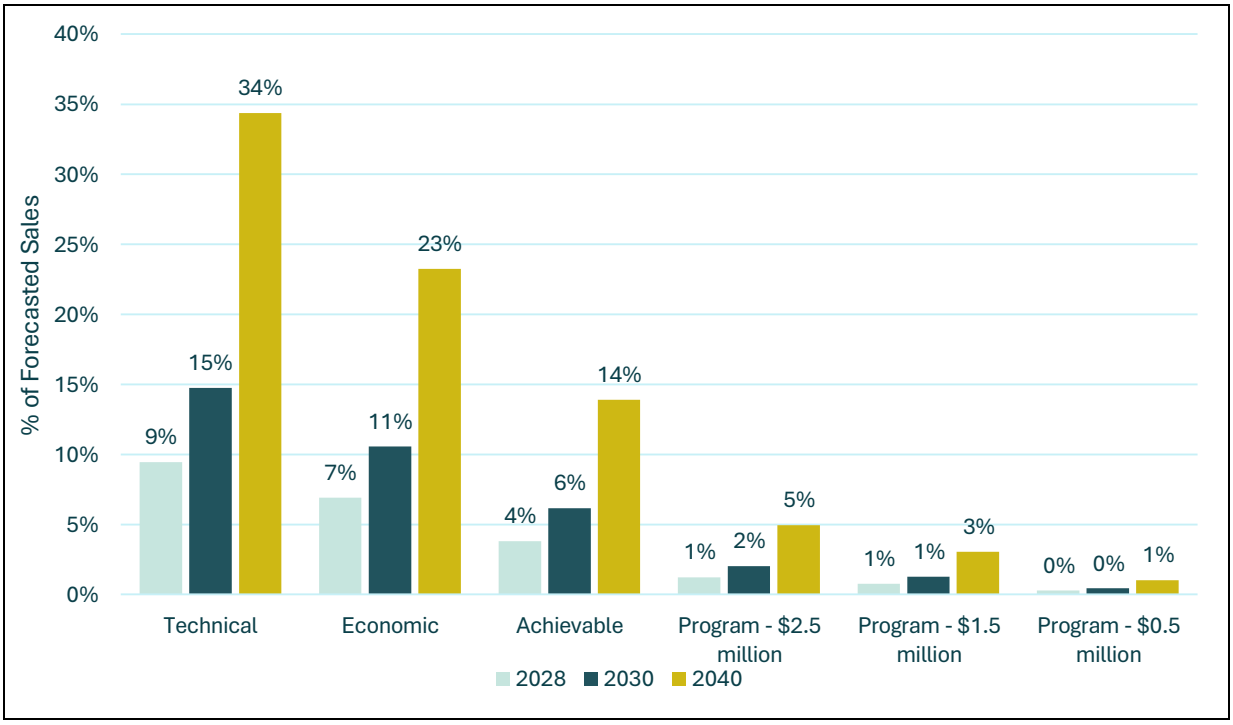


Table 4.5(a) provides a summary of the 15-year energy, summer demand, and winter demand potential.

Table 4.5(a)
15-Year Summary Results for Energy and Demand

Potential	MWh	Summer MW	Winter MW
Technical	792,672	188.7	131.2
Economic	535,956	106.4	107.8
Achievable	320,328	54.6	56.9
Program - $2.5 million	114,239	23.7	21.7
Program - $1.5 million	70,317	14.3	11.8
Program - $0.5 million	23,753	4.5	3.7

Based on the results of the achievable potential analysis, Big Rivers chose to evaluate the energy efficiency programs listed in Table 4.5(b) as part of its DSM study.

Table 4.5(b)
List of Programs Evaluated in the Study

Sector	Program Name
Residential	Energy Star Refrigerator / Refrigerator Recycle Program
Residential	Energy Star Clothes Washer / Dryer Program
Residential	Heat Pump Program
Residential	Ductless Heat Pump Program
Residential	Smart Thermostat Program
Residential	New Construction Program
Commercial/Industrial	C&I Custom Program

These programs represent the end-uses and equipment that hold significant opportunity for cost-effective savings in the residential and commercial/industrial

sector.[71] 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 three different funding scenarios: a $2.5 million incentive scenario, a $1.5 million incentive scenario, and a $0.5 million incentive scenario. In each case, the residential and non-residential sectors were allocated 50% of the incentive budget.

Table 4.5(c) shows the net present value benefits, costs, and benefit-cost ratios for the three Program Potential scenarios examined in this study. The overall cost-effectiveness ratios have decreased since the last study but still indicate that the program potential scenarios are cost-effective overall. There are several reasons for decreased cost-effectiveness including reduced opportunity for low-cost lighting savings due to changing market conditions and the effect of standards. The avoided capacity costs used to value demand savings also decreased since the last study.

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[71] For purposes of this study, the "Commercial and Industrial" category consists of customers served under Big Rivers' Standard Rate Schedule RDS – Rural Delivery Service ("Big Rivers' Rural Delivery Service Tariff").

Table 4.5(c)

Program Potential Cost-Effectiveness (TRC Test)

Potential	NPV Benefits	NPV Costs	NPV Savings (Benefits - Costs)	TRC Test Ratio
Program - $2.5 million	$82.3	$42.4	$40.0	1.9
Program - $1.5 million	$49.0	$25.4	$23.6	1.9
Program - $0.5 million	$16.0	$8.5	$7.5	1.9

Figure 4.5(b) provides the 3-year, 5-year, and 15-year program potential for each funding scenario. The $2.5 million funding scenario program potential is 1.2% of forecast sales over the 3-year timeframe and rises to 5.0% across the 15-year timeframe. The $1.5 million funding scenario program potential is 0.8% of forecasted sales over the 3-year timeframe and rises to 3.0% across the 15-year timeframe. The $0.5 million funding scenario program potential is 0.3% of forecast sales over the 3-year timeframe and rises to 1.0% across the 15-year timeframe.

Figure 4.5(b)

Electric Energy Cumulative Annual Program Potential

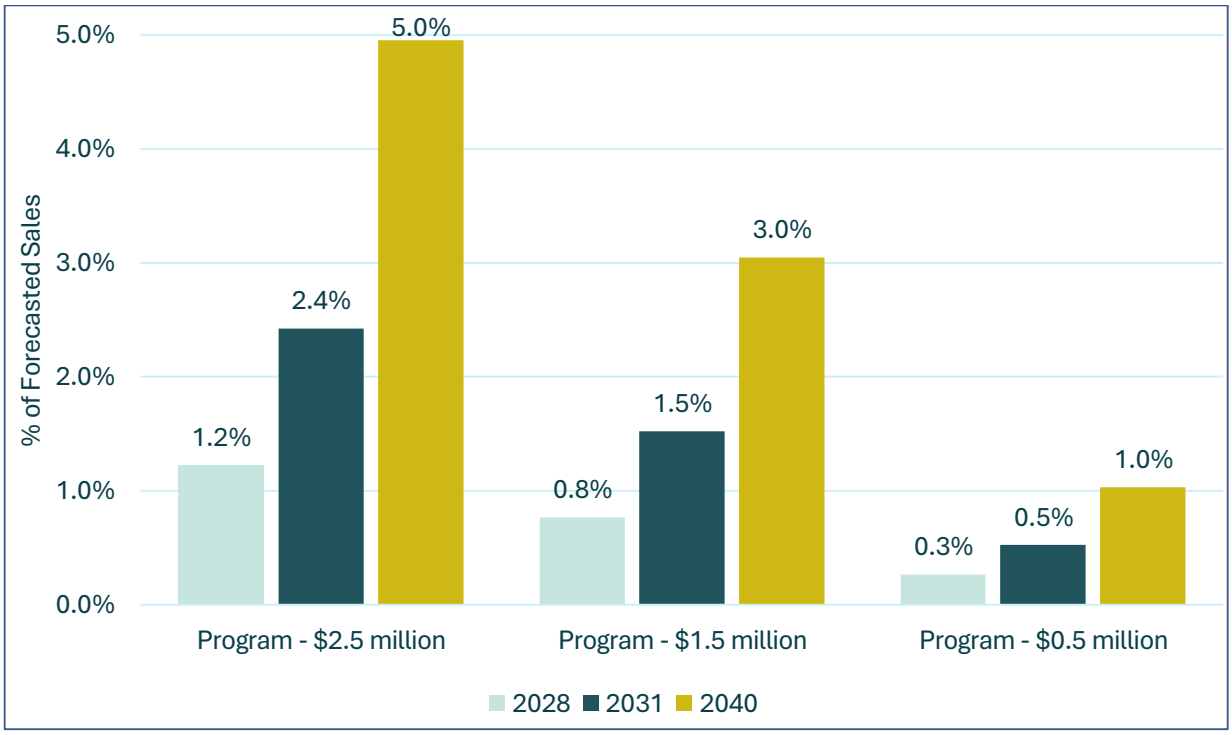


Table 4.5(d) provides 1-, 2-, 3-, 5-, and 15-year estimates of cumulative annual program potential for energy, summer peak demand, and winter peak demand. By 2028, the program potential is nearly 27,000 MWh, 17,000 MWh, and 6,000 MWh for the $2.5 million, $1.5 million, and $0.5 million program potential scenarios, respectively. Summer peak demand program potential is 4.5 MW, 3.0 MW, and 0.9 MW by 2028 for the respective $2.5 million, $1.5 million, and $0.5 million program potential scenarios.

Table 4.5(d)

Program Potential Summary

	2027	2028	2029	2031	2041
Annual Energy (MWh)					
Program - $2.5 million	8,734	17,723	26,883	45,066	114,239
Program - $1.5 million	5,479	11,115	16,854	28,272	70,317
Program - $0.5 million	1,887	3,827	5,801	9,731	23,753
Summer Peak Demand (MW)					
Program - $2.5 million	0.9	2.7	4.5	8.1	23.7
Program - $1.5 million	0.6	1.8	3.0	5.4	14.3
Program - $0.5 million	0.2	0.6	0.9	1.7	4.5
Winter Peak Demand (MW)					
Program - $2.5 million	1.6	3.3	4.9	8.3	21.7
Program - $1.5 million	0.9	1.8	2.7	4.5	11.8
Program - $0.5 million	0.3	0.6	0.9	1.4	3.7

4.5.1 Energy Efficiency Program Potential Scenarios

The program potential assessment involved six residential programs and one C&I program. Each of these programs was assigned an annual budget. The resulting savings estimated for each program are shown for each of the three incentive scenarios.

Table 4.5.1(a)

$0.5 Million Scenario – MWh Savings by Program

Program Name	2027	2028	2029	2031	2041
Refrigerator / Refrigerator Recycle Program	166	331	497	828	1,159
Clothes Washer / Dryer Program	146	293	439	731	2,048
Heat Pump Program	68	135	200	328	952
Ductless Heat Pump Program	107	213	319	530	1,560
Smart Thermostat Program	148	295	443	738	1,623
New Construction Program	123	246	369	615	1,844
C&I Custom Program	1,130	2,314	3,536	5,962	14,567
Total	**1,887**	**3,827**	**5,801**	**9,731**	**23,753**

Table 4.5.1(b)

$1.5 Million Scenario – MWh Savings by Program

Program Name	2027	2028	2029	2031	2041
Refrigerator / Refrigerator Recycle Program	166	331	497	828	1,159
Clothes Washer / Dryer Program	591	1,181	1,782	3,007	8,810
Heat Pump Program	274	544	811	1,347	4,077
Ductless Heat Pump Program	190	379	567	942	2,774
Smart Thermostat Program	596	1,191	1,798	3,032	7,064
New Construction Program	273	546	792	1,229	2,732
C&I Custom Program	3,390	6,943	10,607	17,887	43,701
Total	**5,480**	**11,115**	**16,854**	**28,272**	**70,317**

Table 4.5.1(c)

$2.5 Million Scenario – MWh Savings by Program

Program Name	2027	2028	2029	2031	2041
Refrigerator / Refrigerator Recycle Program	166	331	497	828	1,159
Clothes Washer / Dryer Program	813	1,625	2,438	4,063	11,378
Heat Pump Program	823	1,631	2,405	3,954	10,467
Ductless Heat Pump Program	190	379	614	1,083	3,375
Smart Thermostat Program	820	1,639	2,459	4,098	12,293
New Construction Program	273	546	792	1,229	2,732
C&I Custom Program	5,650	11,571	17,678	29,811	72,835
Total	**8,734**	**17,723**	**26,883**	**45,066**	**114,239**

Big Rivers and the Member Cooperatives will continue to seek and evaluate new technologies and opportunities to benefit the 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 spending to other programs and sectors.

Residential Refrigerator / Refrigerator Recycle Program

The Refrigerator Recycle Program promotes the installation of higher efficiency refrigerators through the removal and recycling of older, more inefficient units. Incentives offered through this program are designed to encourage the retirement of outdated units that contribute to higher energy consumption and peak demand levels.

Residential Clothes Washer / Dryer Program

The Residential Clothes Washer / Dryer Program promotes installation of higher efficiency clothes washers and dryers. Incentives are provided to offset the higher upfront cost of qualifying efficient washers and dryers and to encourage the replacement of standard efficiency appliances.

Residential Heat Pump Program

The Residential Heat Pump Program promotes increased adoption of high-efficiency heat pump systems for space heating and cooling. Incentives are

designed to reduce the cost of replacing less efficient heating and cooling systems with qualifying heat pumps.

Residential Ductless Heat Pump Program

The Residential Ductless Heat Pump Program promotes increased use of high-efficiency ductless heat pump systems, which can be beneficial in homes without existing ductwork or in zones requiring supplemental heating or cooling. Incentives encourage adoption of these systems by reducing upfront costs.

Residential Smart Thermostat Program

The Residential Smart Thermostat Program promotes increased use of smart thermostats that enable automated temperature control, scheduling, and remote connectivity features. Program incentives support the adoption of qualifying devices that help customers optimize usage through reducing energy consumption during peak periods.

Residential New Construction Program

This Residential New Construction Program provides incentives to homeowners and builders to use energy efficient building standards. Incentives through this program are intended to encourage the incorporation of energy efficient building envelopes, equipment, and systems at the time of construction resulting in long-term energy savings.

Commercial and Industrial Custom Program

The Custom Program promotes the implementation of customized energy-saving projects at any qualifying customer facilities. Incentives (typically on a $/kWh or kW saved basis) promoted through this program serve to reduce the cost of implementing energy-reducing projects and upgrading to high-efficiency equipment. Due to the nature of a custom EE program, a wide variety of projects are eligible across all electric end-uses where savings can be reasonably quantified.

4.6 Demand Response Methodology

The Market Potential Study focused on energy efficiency programs but also included an evaluation of possible demand response programs in Big Rivers' territory. This section provides an overview of the results of the demand response analysis. This section provides an overview of the demand response potential methodology. Summary results of the demand response analysis are provided in Chapter 6, Electric Integration Analysis.

4.6.1 Definition of Demand Response

According to FERC, demand response is defined as changes in electric usage by demand-side resources from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized. FERC's definition of demand response

conforms to the NERC definition developed by a consortium of utilities and end users.

This study uses the FERC definition of demand response so that all potential DR, including rate options, are identified. Big Rivers' integrated resource planning team will analyze and adjust as necessary the identified DR potential for how DR potential will be used to construct alternative resource plans.

4.6.2 Demand Response Program Options

Big Rivers does not currently operate any demand response programs. However, the Company has developed an internal process for administering MISO's Load Modifying Resource ("LMR") program on behalf of the Members' industrial members. The Commission recently approved a LMR Agreement among Big Rivers, Kenergy and Pratt Paper (KY), LLC ("Pratt").[72] While, Big Rivers does not provide electric service to any retail or wholesale customers under an interruptible tariff, the Retail Electric Service Agreement among Big Rivers, Kenergy, and Justified DataPower LLC, a subsidiary of TeraWulf Inc. gives Big Rivers and Kenergy the right to curtail TeraWulf's load before any non-interruptible load to resolve local voltage issues, to preserve system integrity, to

[72] *See* Ky. P.S.C. Tariff Filing System ID No. TFS2026-00068 (Filed Feb. 27, 2026). Pratt's registered demand reduction capability will fluctuate depending on the MISO Season, with a Maximum Resource Commitment of 17MW for the MISO 2026-2027 planning year.

comply with MISO rules or directives, or in the event MISO declares an Energy Emergency Alert Level 3.[73] [74]

Table 4.6.2(a) provides a brief description of the demand response program options considered and identifies the eligible customer segment for each demand response program that was considered in this study.

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[73] *In the Matter of: Electronic Filing of Big Rivers Electric Corporation of a Retail Electric Service Agreement with Justified DataPower LLC, a Subsidiary of TeraWulf, Inc.*, Case No. 2026-00115.

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

Table 4.6.2(a)

Demand Response Program Options

Demand Response Program Option	Description	Eligible Markets
Direct Load Control (DLC) Air Conditioning Switch	The compressor of the air conditioner is remotely shut off (cycled) by the system operator for periods that may range from 7 ½ to 15 minutes during every 30-minute period (i.e., 25%-50% duty cycle). Controlled via load control switch. Participant cannot override control.	Residential, Small C&I
DLC Thermostat	The air conditioner or electric heating is remotely shut off (cycled) by the system operator for periods that may range from 7 ½ to 15 minutes during every 30-minute period (i.e., 25%-50% duty cycle). Controlled via smart thermostat. Participant has option to override control.	Residential, Small C&I
DLC Water Heater Switch	The water heater is remotely shut off by the system operator using a load control switch for periods normally ranging from 2 to 4 hours using a load control switch.	Residential, Small C&I
DLC Water Heater Grid-Enabled	The grid-enabled water heater is equipped with a smart controller that allows the utility to remotely shut off the water heater for periods normally ranging from 2 to 4 hours.	Residential, Small C&I
DLC Swimming Pool Pump	The swimming pool pump is remotely shut off by the system operator for periods normally ranging from 2 to 4 hours.	Residential
DLC Electric Vehicle	DLC of electric vehicles relies on communication (i.e., “dispatch”) signals originating from a utility or aggregator and sent to a vehicle or charger to control charging in a predetermined manner. Can be events-based to control load during a limited number of events in a given time period (season or annually) or use continuous management to control load when the vehicle is connected to the charger.	Residential & Commercial EV Chargers
Electric Vehicle Time of Use (TOU)	A special electricity pricing structure designed for EV owners where the price of electricity varies based on the time of day it’s used.	Residential & Commercial EV Chargers
TOU Rate	A retail rate with different prices for usage during different blocks of time. Daily pricing blocks could include on-peak, mid-peak, and off-peak periods.	Residential, Small C&I, Large C&I
Critical Peak Pricing (CPP) Rate	A retail rate in which an extra-high price for electricity is provided during critical periods (e.g. 100 hours) of the year. Prices can be fixed or fluctuate with the market. Market-based prices are typically provided on a day-ahead basis, or an hour-ahead basis.	Residential, Small C&I, Large C&I
Peak Time Rebate	Customers are given a rebate for less consumption during times selected as critical periods.	Residential
Battery Storage	Uses the battery to reduce a home or facility’s demand during peak or DR event hours, without requiring the customer to curtail their power. Instead of turning off equipment, the battery discharges power to offset load—or shifts charging to off-peak periods—so the utility sees a drop in grid demand.	Residential & Commercial Customers with Solar

Demand Response Program Option	Description	Eligible Markets
Generators	Allows the utility to turn customer's generator on and off for short periods of time during specific times of the day. The goal of DR is to enable the utility to reduce pressure on the grid and avoid rolling black outs during times of high usage.	Residential
Conservation Voltage Reduction (CVR)	A grid management strategy where the utility temporarily reduces distribution system voltage to lower customer power consumption during peak periods.	Residential, Small C&I, Large C&I
Interruptible Rate	A special tariff offered to large commercial & industrial (C&I) customers where they receive reduced energy or demand charges in exchange for agreeing to curtail a specified amount of load when the utility or grid operator calls an event.	Large C&I
Capacity Bidding	Flexible bidding program offering qualified businesses payments for agreeing to reduce load when an event is called. Participants make monthly nominations and receive capacity payments based on the amount of capacity reduction nominated each month. The amount of capacity nomination can be adjusted on a monthly basis. The program can be Internet-based, providing ready access to program information and ease-of-use. Penalties occur if load nominations are not met. Not all load nominated is necessarily dispatched.	Small C&I, Large C&I

4.6.3 Demand Response Potential Assessment Approach Overview

The analysis of DR, where possible, closely follows the approach outlined for energy efficiency. The framework for assessing the cost-effectiveness of demand response programs is based on *A Framework for Evaluating the Cost-Effectiveness of Demand Response*, a report prepared for the National Forum on the National Action Plan ("NAPDR") on Demand Response. Additionally, GDS reviewed the National Standard Practice Manual published by the National Efficiency Screening Project. GDS utilized this guide to define avoided ancillary services and energy and/or capacity prices.

The demand response analysis was conducted using the GDS Demand Response Model. The DR Model determines the estimated savings for each

demand response program by performing a review of all benefits and costs associated with each program. GDS developed the model such that the value of future programs could be determined and will help facilitate demand response program planning strategies. The model contains approximately 50 required inputs for each program including: expected life, coincident peak ("CP") kW load reductions, proposed rebate levels, program related expenses such as vendor service fees, marketing and evaluation cost and on-going operation and maintenance ("O&M") expenses. This model and future program planning features can be used to standardize the cost-effectiveness screening process between Big Rivers departments interested in the deployment of demand response resources.

The TRC Test was used to determine the cost-effectiveness of each demand response program. Benefits are based on avoided generation capacity, energy (including load shifting) and Transmission and Distribution ("T&D") infrastructure costs. Costs include incremental program equipment costs (such as control switches or smart thermostats), fixed program capital costs (such as the cost of a central controller), program administrative, marketing and evaluation costs. Incremental equipment program costs are included for both new and replacement units (such as control switches) to account for units that are replaced at the end of their useful life.

4.6.4 Avoided Costs

Demand response avoided costs are consistent with those utilized in the energy efficiency potential analysis and were provided by Big Rivers. The primary benefit of demand response is avoided generation capacity, resulting from a reduction in the need for new peaking generation capacity. Demand response can produce energy-related benefits. Demand response programs can also potentially delay the construction of new transmission and distribution lines and facilities, which is reflected in avoided T&D costs. If the demand response option is considered "load shifting," such as direct load control of electric water heating, the consumption of energy is shifted from the control period to the period immediately following the period of control. If the program is not considered to be "load shifting" the measure is turned off during peak control hours, and the energy is saved altogether.

4.6.5 Demand Response Program Assumptions

This section briefly discusses the general assumptions and sources that will be used to complete the demand response potential analysis. All assumptions with sources are included in Appendix B, Demand-Side Management Potential Study.

Load Reduction: Demand reductions were based on various secondary data sources including evaluation studies, FERC and other industry reports, and other demand response potential studies that conducted primary research. Some programs were calculated based on a per-unit kW demand reduction and other

program options were assumed to reduce a percentage of the total facility peak load. These load reductions can be found in Table 5.6.5(a).

Table 4.6.5(a)

Demand Response Load Reduction Impacts

Program	Residential Load Reduction (kW)	Non-Residential Load Reduction (kW)
DLC Central AC Switch	0.79 kW (Summer only)	1.65 kW (Summer only)
DLC Thermostat	0.93 kW in Summer; 1.61 kW in Winter	1.95 kW in Summer; 2.54 kW in Winter
DLC Water Heater Switch	0.39 kW in Summer; 0.59 kW in Winter	1.5 kW in Summer; 1.5 kW in Winter
DLC Water Heater Grid-Enabled	0.43 kW in Summer; 0.63 kW in Winter	1.5 kW in Summer; 1.5 kW in Winter
DLC Swimming Pool Pump	0.52 kW (Summer only)	N/A
DLC Electric Vehicle	0.295 kW in Summer; 0.35 kW in Winter	0.02 kW in Summer; 0.03 kW in Winter
Electric Vehicle TOU	0.39 kW in Summer; 0.33 kW in Winter	0.02 kW in Summer; 0.03 kW in Winter
TOU Rate	8.6% of CP Billing Demand in Summer; 3.6% in Winter	2% of CP Billing Demand in Summer; 1% in Winter
CPP Rate	12.8% of CP Billing Demand in Summer; 7.7% in Winter	7.9% of CP Billing Demand in Summer; 6% in Winter
Peak Time Rebate	14% of CP Billing Demand in Summer; 8% in Winter	N/A
Battery Storage	3 kW	11.25 kW
Generators	50% of home's load	N/A
Conservation Voltage Reduction	1.7% of CP Billing Demand	1.7% of CP Billing Demand
Interruptible Rate	N/A	23% of CP Billing Demand
Capacity Bidding	N/A	25% of CP Billing Demand

Useful Life: The useful life of equipment used in demand response programs, such as load control switches, smart thermostats, or batteries, was determined using TRMs and data from manufacturers. This useful life was used to determine when equipment needs to be re-installed in the study after the device has failed, therefore adding a second equipment cost for some participants in the

study. GDS used a useful life of 11 years for smart thermostats,[75] 10 years for level 2 EV chargers,[76] 10 years for battery storage,[77] 19 years for generators,[78] and 10 years for load switches.[79]

Equipment and Incentive Costs: Equipment costs were included for each new participant. Annual incentives were included either on a per participant, per kW or per kWh basis, see Table 4.6.5(b). For a few of the programs, the utility is incentivizing the customer by paying for a portion of the equipment cost.

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[75] Illinois Technical Reference Manual Version 12.0 (2023).

[76] U.S. Department of Energy, *Costs Associated with Non-Residential EV Supply* Equipment (2015).

[77] Tesla, Inc., Tesla Energy Storage Product Warranty.

[78] Federal Emergency Management Agency, emergency generator guidance and lifecycle information.

[79] Freeman, Sullivan & Co., *Cost Effectiveness of Con Edison Demand Response Programs* (2013).

Table 4.6.5(b)

Assumed Base Case Equipment and Incentive Costs

	DR Program Option	Incentive Costs	Equipment Costs
Residential	DLC Central AC Switch	$31/participant-year + one-time incentive of $28	$230/new participant
	DLC Thermostat	$32/participant-year + one-time incentive of $60	$130/new participant
	DLC Water Heater Switch	$30/participant-year	$330/new participant
	DLC Water Heater Grid-Enabled	$30/participant-year + one-time incentive of $400	$50/new participant
	DLC Swimming Pool Pump	$12/participant-year	$141/new participant
	DLC Electric Vehicle	$39/participant-year + one-time incentive of $155	$0
	Electric Vehicle TOU	$0	$0
	TOU Rate	$0	$0
	CPP Rate	$0	$0
	Peak Time Rebate	$1/kWh saved	$0
	Battery Storage	$400/participant-year	$0 (assume BYOD program)
	Generators	$250/participant-year + one-time incentive of $100	$0
	Conservation Voltage Reduction	$0	$0
Non-Residential	DLC Central AC Switch	$38/participant-year + one-time incentive of $28	$387/new participant
	DLC Thermostat	$54/participant-year + one-time incentive of $88	$102/new participant
	DLC Water Heater Switch	$30/participant-year	$330/new participant
	DLC Water Heater Grid-Enabled	$30/participant-year + one-time incentive of $400	$50/new participant
	DLC Electric Vehicle	$39/participant-year + one-time incentive of $155	$0
	Electric Vehicle TOU	$0	$0
	TOU Rate	$0	$0
	CPP Rate	$0	$0
	Battery Storage	$1500/participant-year	$0 (assume BYOD program)
	Conservation Voltage Reduction	$0	$0
	Interruptible Rate	$8/kW-month	$0
	Capacity Bidding	$80/kW pledged	$0

Eligible Market Size: For direct load control programs, the size of the eligible market was determined by multiplying the forecast of Big Rivers' customers by the saturation of the end use to be controlled. End use saturations were obtained from the 2025 Big Rivers saturation data as well as Commercial Buildings Energy Consumption Survey ("CBES") for data that was not included in the 2025 saturation data.

Program Adoption Levels: Long-term program adoption levels (or "steady state" participation) represent the enrollment rate once the fully achievable participation has been reached. GDS has reviewed industry data and program adoption levels from several utilities' DR programs.

Customer participation in new demand response programs is assumed to reach the steady state adoption rate over a five-year period. The path to steady state customer participation follows an "S-shaped" curve, in which participation growth accelerates over the first half of the five-year period, and then slows over the second half of the period (Figure 4.6.5(a)). GDS used other research or potential studies to determine steady state participation rates. Table 5.6.5(c) provides the Base Case long-term adoption rates for achievable potential.

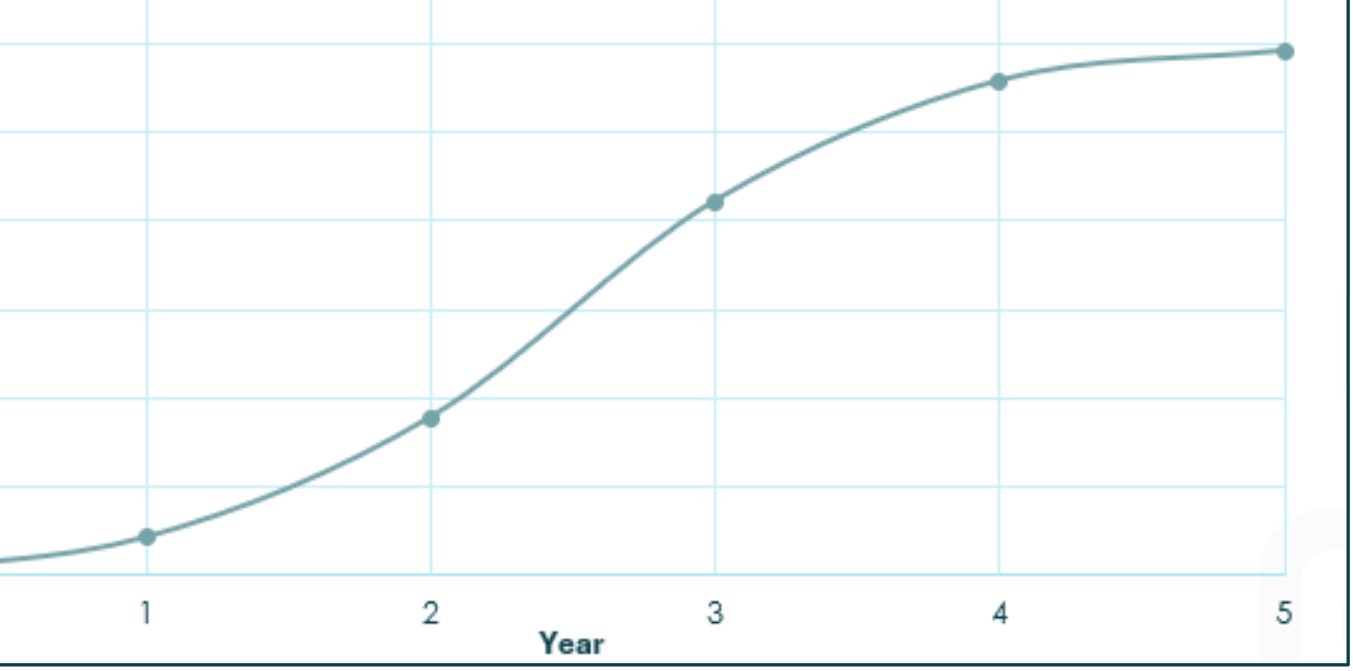

1
2
3
4
5
Year

Table 4.6.5(c)

Base Case Adoption Rates

	DR Program Option	Steady State Adoption Rate
Residential	DLC Central AC Switch	11.5%
	DLC Thermostat	20%
	DLC Water Heater Switch	20%
	DLC Water Heater Grid-Enabled	10%
	DLC Swimming Pool Pump	20%
	DLC Electric Vehicle	20%
	Electric Vehicle TOU	20%
	TOU Rate	10.2%
	CPP Rate	15%
	Peak Time Rebate	13%
	Battery Storage	50%
	Generators	5%
	Conservation Voltage Reduction	100%
Non-Residential	DLC Central AC Switch	10%
	DLC Thermostat	14%
	DLC Water Heater Switch	20%
	DLC Water Heater Grid-Enabled	10%
	DLC Electric Vehicle	10%
	Electric Vehicle TOU	20%
	TOU Rate	16%
	CPP Rate	15%
	Battery Storage	50%
	Conservation Voltage Reduction	100%
	Interruptible Rate	19%
	Capacity Bidding	21.5%

Double-counting savings from demand response programs that affect the same end uses is a common issue that must be addressed when calculating the demand response savings potential. For example, a customer cannot elect to participate in both DLC programs and rate programs and claim savings from both programs for curtailing the same end use. One cannot save a kW of load in a specific hour more than once. In general, the hierarchy of demand response

programs is accounted for by subtracting the number participants in a higher priority program from the eligible market for a lower priority program. Table 4.6.5(d) shows the hierarchy for each sector, with 1 being the top priority.

Table 4.6.5(d)

Base Case DR Hierarchy for Each Sector

Order	Residential Hierarchy	C&I Hierarchy
1	Direct Load Control	Direct Load Control
2	Peak Time Rebate	Critical Peak Pricing
3	Critical Peak Pricing	Time of Use
4	Time of Use	Interruptible Rate
5		Capacity Bidding

4.6.6 Demand Response Program Potential Scenarios

Three budget scenarios were analyzed to estimate program potential under funding levels of $0.5 million, $1.5 million, and $2.5 million. Big Rivers identified the highest-priority programs, which were included in these scenarios. The available budget was initially allocated equally across these programs. If a program did not require its full allocation to reach the achievable potential, any remaining funds were redistributed among the other programs that had not yet reached their total achievable potential level. To align program costs with the budget scenarios, program impacts were scaled down by reducing the number of program participants until the target budget was reached.

4.7 Demand Response Potential

Consistent with the energy efficiency evaluation, DR programs are primarily evaluated based on the TRC test, but UCT and Participant Cost Test ("PCT") were also calculated. Table 4.7(a) provides the results of the TRC test for achievable potential.

Table 4.7(a)
Demand Response Programs Achievable Potential
Cost-Effectiveness Results

Sector	Program	TRC
Residential	DLC AC Switch	1.34
	DLC Thermostat	1.87
	DLC Water Heater Switch	0.69
	DLC Water Heater Grid-Enabled	0.49
	DLC Swimming Pool Pump	1.00
	DLC Electric Vehicle	0.41
	Electric Vehicle TOU	2.74
	Time of Use Rate	2.84
	Critical Peak Pricing Rate	6.36
	Peak Time Rebate	1.63
	Battery Storage	0.25
	Generators	0.51
	CVR	6.82
C&I	DLC AC Switch	2.27
	DLC Thermostat	2.73
	DLC Water Heater Switch	3.42
	DLC Water Heater Grid-Enabled	1.67
	DLC Electric Vehicle	0.00
	Electric Vehicle TOU	0.00
	Time of Use Rate	2.14
	Critical Peak Pricing Rate	9.50
	Battery Storage	0.16
	Capacity Bidding	0.95
	Interruptible Rate	1.38
	CVR	10.63

Table 4.7(b) provides 1-, 2-, 3-, 5-, and 15-yr estimates of cumulative annual technical, economic, and achievable potential for energy.

Table 4.7(b)
Cumulative Annual Demand Response MW Potential Summary

	2027	2028	2029	2031	2041
Technical	650	593	516	460	416
Economic	369	351	322	299	278
Achievable (Summer)	12	36	69	93	93

Similar to the energy efficiency analysis, achievable potential was calculated based on estimates of the amount of demand response that could be realistically achieved over the study period. Program potential was then considered at three different funding scenarios: a $2.5 million scenario, a $1.5 million scenario, and a $0.5 million scenario. Summer demand potential is shown in Figure 5.7(a) in 2027, 2031, and 2041. Table 4.7(c) shows the summer and winter demand potential in 2041.

Figure 4.7(a)

Demand Response Potential Savings Summary

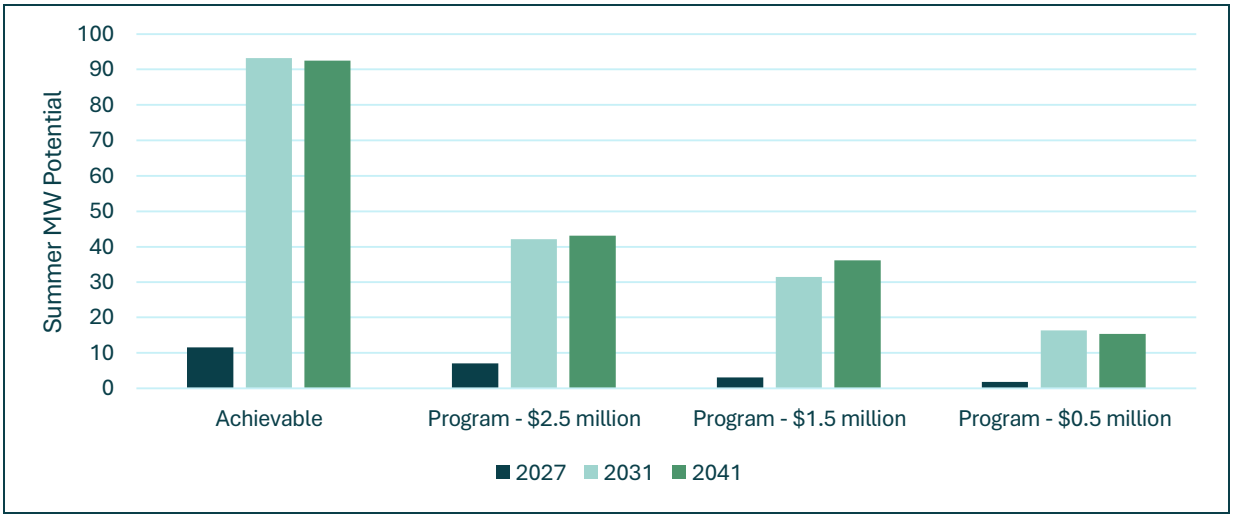


Table 4.7(c)

Seasonal Summary Results for Demand Response in Final Year of Study

Potential	Summer MW	Winter MW
Achievable	92.5	82.6
Program - $2.5 million	43.1	43.5
Program - $1.5 million	36.1	32.8
Program - $0.5 million	15.4	16.0

Table 4.7(d)

Summer Demand Response Potential by Program in Final Year of Study

Summer MW Potential	Achievable	Program - $2.5 million	Program - $1.5 million	Program - $0.5 million
Residential DLC Thermostat	12	5	2	1
Residential CVR	5	5	5	5
Residential DLC Electric Vehicle	3	1	0.3	N/A
Residential Electric Vehicle TOU	4	4	4	N/A
Residential TOU	1	2	2	N/A
Residential CPP	4	5	5	N/A
Residential DLC AC Switch	8	N/A	N/A	N/A
Residential DLC Water Heater Switch	5	N/A	N/A	N/A
Residential DLC Water Grid Enabled	2	N/A	N/A	N/A
Residential DLC Swimming Pool Pump	2	N/A	N/A	N/A
C&I DLC Thermostat	4	4	3	1
C&I DLC Water Heater Switch	3	3	3	1
C&I Capacity Bidding	10	3	1	0.4
C&I CVR	7	7	7	7
C&I TOU	1	1	1	N/A
C&I CPP	4	4	4	N/A
Residential Peak Time Rebate	4	N/A	N/A	N/A
Residential Battery Storage	0.1	N/A	N/A	N/A
Residential Generator	1	N/A	N/A	N/A
C&I DLC AC Switch	2	N/A	N/A	N/A
C&I DLC Water Heater Grid Enabled	2	N/A	N/A	N/A
C&I DLC Electric Vehicle	0.001	N/A	N/A	N/A
C&I Electric Vehicle TOU	0.002	N/A	N/A	N/A
C&I Battery Storage	0.1	N/A	N/A	N/A
C&I Interruptible Rate	10	N/A	N/A	N/A

4.8 DERMS Development Plan

In Fall 2025, Big Rivers, in collaboration with ACES, initiated a structured research and procurement process to identify a scalable Distributed Energy Resource Management System ("DERMS") capable of supporting deployment across Big Rivers and its Member-Owners. The Request for Proposals ("RFP")

process was designed to establish a controlled vendor-evaluation framework, define functional and technical requirements, and generate comparable data across solution providers. The RFP was issued in December 2025 and distributed to 16 targeted vendors selected for their relevance to DERMS, demand response, and distributed energy resource integration.

Between January and February 2026, Big Rivers and ACES received seven (7) responses from targeted vendors, as well as three additional unsolicited responses submitted through ACES's RFP portal website. Of the ten total responses received, eight vendors advanced to the demonstration phase, providing the combined Big Rivers/ACES evaluation team with an opportunity to observe platform capabilities, assess alignment with stated requirements, and collect qualitative and comparative evidence regarding each vendor's technical approach.

Following completion of the demonstrations, the ACES team performed a comparative analysis of the vendor responses, including observed functionality, implementation feasibility, system scalability, operational fit, and anticipated value to Big Rivers and its Member-Owners. In April 2026, this analysis resulted in a shortlist of three vendors for further consideration. The shortlisted vendors then proceeded through a second phase of evaluation, during which Big Rivers and ACES further tested assumptions, assessed risks, and prioritized finalists based on the evidence gathered during the RFP and demonstration process. This evaluation informed the recommendation presented to the Big Rivers Board of Directors. In May 2026, Big Rivers selected a preferred vendor and initiated

contract negotiations, which culminated in a fully executed multi-year agreement in August 2026.

Over the next several months, the Big Rivers team will apply a multi-track implementation approach to advance its Demand Response initiative including related pilot programs. One workstream will focus on implementation of the DERMS software platform, which will serve as the technical foundation for future demand response technologies and distributed energy resource coordination. A parallel workstream will focus on developing and filing proposed tariff revisions with the Commission for pilot programs intended to test program design, customer participation assumptions, operational performance, and measurable system benefits. Together, these efforts will promote an evidence-based transition from vendor selection to platform deployment, pilot program execution, and ongoing evaluation.

Chapter 5

ENVIRONMENTAL



5. ENVIRONMENTAL

Pursuant to the regulatory framework administered by the Kentucky Public Service Commission under 807 KAR 5:058, this section details the current and emerging environmental regulations impacting our power-production resources. Operating as a cooperative means that the capital costs of environmental compliance are carried directly by our local member-owners in western Kentucky. Consequently, we navigate a complex and ever-evolving regulatory landscape with an increased focus on risk management and cost-effectiveness. Our planning is regulated by the U.S. Environmental Protection Agency ("EPA") and the Kentucky Energy and Environment Cabinet.

Big Rivers' power generation portfolio is intentionally diversified. Active resources include the natural gas-fired Green Units 1 and 2, along with the coal-fired Wilson Unit. The portfolio formerly included the natural gas-fired Reid CT, which has been offline since 2024. In addition to its thermal fleet, Big Rivers holds purchased power agreements for 178 MWs of hydroelectric capacity through the Southeastern Power Administration ("SEPA") and160 MWs of solar power that came online in 2025. Concurrently, Big Rivers is advancing demolition and decommissioning across its retired coal fleet:

- Kenneth C. Coleman Station (Units 1-3): Decommissioning of the three units was completed in December 2025.

- Robert A. Reid Unit 1 & Henderson Municipal Power and Light ("HMP&L") Station 2: Demolition at both sites remains underway through 2026, with full completion projected for December 2027.

Herein, Big Rivers details the scope of current and proposed environmental regulations that directly impact our power-generating fleet, specifically addressing power generation emissions and waste streams. Although prospective rulemakings introduce unavoidable uncertainty, Big Rivers affirms its readiness to resolve the legal, regulatory, and technological complexities that lie ahead.

5.1 Clean Air Regulations – Greenhouse Gas Rules

Since 2015, EPA has pursued rulemakings to regulate greenhouse gas ("GHG") emissions from the power sector using Clean Air Act ("CAA") Section 111 (New Source Performance Standards (NSPS)). These rulemakings have significantly fluctuated over the years due to judicial challenges and changes in political administration. The Obama Administration first promulgated the final Clean Power Plan ("CPP") in 2015, mandating a significant reduction in fossil fuel-fired generation. The U.S. Supreme Court stayed the CPP on February 9, 2016. On July 8, 2019, EPA finalized a replacement for the CPP, known as the final Affordable Clean Energy Rule ("ACE"), which utilized a cooperative federalism approach. On January 19, 2021, the U.S. Court of Appeals for the D.C. Circuit vacated ACE, the repeal of the CPP, and the Section 111 timing provisions within the implementing regulations. On June 30, 2022, the Supreme Court held

in *West Virginia v. EPA*[80] that EPA acted beyond its CAA authority by finalizing the expansive CPP.

On May 9, 2024, EPA finalized a new set of GHG regulations (the "2024 GHG Rule"). The 2024 GHG Rule imposed stringent requirements for new and reconstructed fossil fuel-fired CTs (combustion turbines) and modified coal-fired steam generating units and set the best system of emissions reductions ("BSER") and emission guidelines for GHG emissions from existing coal-fired and oil/gas-fired steam generating units. Existing CTs were not included in the regulation. The 2024 GHG Rule remains in place until EPA finalizes a repeal and/or replacement for it.

Regarding the specific requirements of the 2024 GHG Rule, EPA finalized new CO_2 emission limits for new stationary CTs and modified coal-fired steam generating units constructed (or reconstructed) based on capacity factor (low, intermediate, or base load) and based on the ratio of heat input of the fuel combusted (natural gas or fuel oil). The Rule did not identify a control technology as BSER but emission rates for baseload units were not achievable without a technology equivalent to the reductions achieved by carbon capture and sequestration ("CCS").

For existing coal and oil-fired units, units were categorized based on retirement date, which dictated the BSER. The Rule exempted units electing to

[80] *West Virginia v. EPA*, 597 U.S. 697 (2022)

retire by January 1, 2032. Long-term units had to apply CCS as BSER, while medium-term units must achieve co-firing natural gas at 40% of the total heat input. These requirements were to be implemented through state plans for existing units. States were to submit these plans by May 11, 2026.

After a change of presidential administration, EPA proposed a rule on June 17, 2025, to reverse course from the 2024 GHG Rule. EPA proposed two options. The first would repeal all GHG emission regulations for fossil fuel-fired electric generating Units ("EGUs"). The second would repeal all requirements for existing coal-fired and oil-fired units, and for new gas-fired units, repeal CCS requirements but retain Phase 1 CO2 requirements based on unit efficiency.

On September 17, 2026, EPA promulgated a final rule titled "Partial Repeal of the Carbon Pollution Standards for Fossil Fuel-Fired Electric Generating Units." 91 Fed. Reg. 58954 ("Final Rule"). The Final Rule repeals many provisions of the 2024 Carbon Pollution Standards ("CPS") for GHG emissions from fossil fuel-fired EGUs.

Specifically, the Final Rule repeals all Clean Air Act Section 111 GHG guidelines for existing power plants, including CCS, natural gas co-firing, and alternative retirement dates. The Final Rule also repeals the 2024 CPS standards for new gas-fired units and modified coal units that were based on 90% CCS requirements. This eliminated the "phase 2" provisions of the CPS that mandated 90% CCS for new base-load combustion turbines by 2032.

EPA determined that 90% CCS is not the "best system of emission reduction" ("BSER") for coal-fired steam generating units because (1) 90% CCS has not been adequately demonstrated; (2) the costs of 90% CCS are not reasonable, and (3) the associated degree of emission limitation is not achievable. EPA also determined that 40% natural gas co-firing is not the BSER for existing coal-fired steam generating units because 40% natural gas co-firing constitutes impermissible generation shifting under the Supreme Court's holding in West Virginia v. EPA and is an inefficient use of natural gas. The Final Rule leaves in place the phase 1 "highly efficient" standards for new intermediate and baseload combustion turbines. The Final Rule is effective on November 16, 2026.

On September 17, 2026, a coalition of several environmental groups filed a petition for review of the Final Rule in the United States Court of Appeals for the D.C. Circuit (D.C. Circuit) styled, American Lung Association v. EPA, Case No. 26-1238. The Petitioners in this case are the American Lung Association, American Public Health Association, Clean Air Council, Clean Wisconsin, Environmental Defense Fund, and National Resources Defense Council, and National Resources Defense Council. As of September 23, 2026, Petitioners have not filed a motion to stay the Final Rule.

Also on September 17, 2026, EPA issued a supplemental notice of proposed rulemaking titled "Rescission of the Greenhouse Gas Findings for Fossil Fuel-Fired Power Plants and Repeal of Regulations for Power Plant Greenhouse Gas Emissions Under Clean Air Act Section 111." 91 Fed. Reg. 59002 (Supplemental

Proposal). The Supplemental Proposal provides additional legal justification supporting EPA's prior 2025 Proposal to repeal all Section 111 GHG emission standards for fossil fuel-fired EGUs. See 90 Fed. Reg. 25752 (June 17, 2025) ("2025 Proposal").

The Supplemental Proposal builds on the "primary" justification in the 2025 Proposal, which proposes to conclude that a repeal all GHG standards for power plants is required under the best reading of Section 111 as power plants do not "contribute significantly to dangerous air pollution." In the Supplemental Proposal, EPA is requesting additional comments on an additional legal theory: Whether global climate change concerns, rather than local or regional impacts, can constitute "air pollution" under Section 111. EPA's supplemental legal justification for the repeal of all GHG standards for power plants is based on the theory that the agency lacks the authority to issue these standards under Section 111(b)(1)(A). Specifically, this provision requires EPA to regulate emissions that cause or contribute significantly to "air pollution which may reasonably be anticipated to endanger public health or welfare." Comments on the Supplemental Proposal are due on November 2, 2026.

The 2024 GHG Rule previously applied to all of Big River's operations, although now it would only potentially affect any new generating units it decides to build. Upon the effective date of the Final Rule, existing units will not be subject to the requirements of the 2024 GHG Rule. Consequently, Wilson Station's pulverized coal unit (417 net MW) will no longer be subject to requirements in the

2024 GHG Rule. In addition, the Green Plant has two boiler/turbines (231 MW and 223 MW), each converted from coal-fired to natural gas-fired steam units in 2022. These units are existing gas-steam units but are no longer regulated by the 2024 GHG Rule. Of note, the Final Rule did not repeal the Phase 1 CO2 standards that would apply should Big Rivers decide to construct a new natural gas unit. If the EPA finalizes the Supplemental Proposal, then the Phase 1 standards would be eliminated. As noted above, a litigation challenge of the Final Rule has already been filed, which contributes to the uncertainty of these rules. Big Rivers will continue to monitor the status of the GHG regulations and will modify its planning as warranted by new developments.

5.2 Clean Air Regulations – Cross State Air Pollution Rule

Section 110(a)(2)(D)(i)(I) of the Clean Air Act, also known as the Good Neighbor provision, addresses ozone transport. It requires State Implementation Plans ("SIPs") to contain provisions that prohibit any source or emissions activity that will significantly contribute to nonattainment of a National Ambient Air Quality Standards ("NAAQS"), or interfere with another state's maintenance of a NAAQS. EPA may promulgate a Federal Implementation Plan ("FIP") if EPA disapproves a state's SIP submission or finds a SIP submission incomplete.

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 twenty-two (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.

On February 13, 2023, EPA issued a final rule that disapproved many states' ozone transport SIPs for the 2015 Ozone NAAQS, including Kentucky's plan. After the disapproval, EPA issued the final Good Neighbor Plan establishing FIP requirements to address good neighbor obligations on March 15, 2023. The Good Neighbor Plan was set to significantly tighten NOx emissions for EGUs in Kentucky. It was to take effect beginning in the 2023 ozone season. EPA planned a steep decline in budgets beginning in 2026. However, the Good Neighbor never took effect. On December 6, 2024, the United States Court of Appeals for the Sixth Circuit granted the petition for review of Kentucky's SIP disapproval and vacated and remanded the disapproval to EPA for

reconsideration. The Court determined that the disapproval was arbitrary and capricious. Consequently, Kentucky is not subject to the Good Neighbor Plan.

On January 28, 2026, EPA issued a proposed rule, known as a Phase 1 Rule, to resolve the SIP obligations for Kentucky and nine other States. The Phase 1 Rule is part of a two-phased approach to reconsider the Good Neighbor Plan. EPA plans to finalize the Phase 1 rule by the end of 2026.

Big Rivers is presently subject to the iteration of CSAPR that addresses ozone transport obligations for the 2008 Ozone NAAQS. Kentucky EGUs are in a CSAPR allocation group called Expanded Group 2. Big Rivers anticipates having sufficient allowances to cover the emissions from Big Rivers' units given the typical emissions projects during the ozone season (May to September). Big Rivers also maintains banked allowances in the event that additional allowances are necessary. Big Rivers closely monitors its NO_X tons emitted to ensure that it will have sufficient allowances when true-up of emissions and allowances held takes place. Big Rivers will track further developments as EPA considers finalizing the proposed Phase 1 Rule that includes Kentucky.

5.3 Clean Air Regulations – Mercury Air Toxics Standards

The Mercury Air Toxics Standards ("MATS") are CAA Section 112 Maximum Achievable Control Technology ("MACT") standards for coal-fired and oil-fired EGUs that control hazardous air pollutants ("HAPs"), such as mercury ("Hg"), arsenic, chromium, and nickel, and acid gases (hydrogen chloride ("HCl")

and hydrogen fluoride ("HF")). Non-Hg HAPs are captured by particulate matter ("PM") emission limits as a surrogate. MATS has emissions limitations for HCl and/or SO2 as surrogates and Hg. The initial compliance date for MATS was in the spring of 2015.

As a CAA Section 112 rule, MATS is subject to a one-time Section 112(f) risk review and periodic Section 112(d)(6) technology reviews. This is known as a Risk and Technology Review ("RTR"). Thereafter, Section 112(d)(6) requires EPA to conduct technology reviews at least every eight years.

On May 7, 2024, EPA finalized a reconsideration of the one-time RTR to reflect recent developments in control technologies and the performance of these applicable coal-fired and oil-fired steam generating units (the "2024 MATS RTR"). The 2024 MATS RTR lowered the filterable particulate matter ("fPM") emission standard from 0.030 pound ("lb")/Million British thermal units ("MMBtu") to 0.010 lb/MMBtu. The Rule also removed the option for stack testing to show compliance and required that existing coal-fired EGUs use fPM continuous emissions monitoring systems ("CEMS"). The effective date of the rule was July 8, 2024.

On February 24, 2026, EPA, under the Trump Administration, finalized its repeal of the most significant portions of the 2024 MATS RTR (the "2026 MATS Repeal"), including the more stringent fPM emission standard and use of only CEMS to demonstrate compliance with the fPM standard. The 2026 MATS Repeal is currently effective; however, a coalition of environmental interest groups

filed a petition for review challenging the 2026 MATS Repeal in the U.S. Court of Appeals for the D.C. Circuit.

Big Rivers' only MATS-affected unit is the coal-fired unit at D.B. Wilson Station. D.B. Wilson Station is presently in compliance with the current version of MATS, as modified by the 2026 MATS Repeal. However, even if the D.C. Circuit overturns the 2026 MATS Repeal, D.B. Wilson Station is subject to a Proclamation exempting certain stationary sources from MATS that the President signed on April 8, 2025. That Presidential Proclamation lasts 2 years beyond the 2024 MATS RTR's compliance date, beginning on July 8, 2027, and ending on July 8, 2029. Thus, irrespective of the Court's decision, D.B. Wilson Station has a compliance extension until July 8, 2029. Big Rivers will continue to monitor regulatory and judicial developments that impact the MATS regulations.

5.4 Clean Air Regulations – Particulate Matter NAAQS

On March 6, 2024, EPA published a final rule, "Reconsideration of the National Ambient Air Quality Standards for Particulate Matter," that lowered the primary annual $PM_{2.5}$[81] standard from 12.0 ug/m^3 to 9.0 ug/m^3. On March 6, 2024, a coalition of industry groups filed suit challenging the revised $PM_{2.5}$ NAAQS in the U.S. Court of Appeals for the D.C. Circuit. In June 2026, the D.C. Circuit rejected Petitioners' claims and dismissed the Petitions for Review. Petitioners

[81] *See* 40 C.F.R. § 50.18(a) (defining PM2.5 as "particles with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers").

will have the opportunity to seek review by filing a Writ of Certiorari in the United States Supreme Court.

In Kentucky, Bell, Christian, and Jefferson Counties are projected not to achieve the new $PM_{2.5}$ NAAQS standard based on 2020-2022 data. Big Rivers does not serve any member-cooperatives in these counties. Although the lower PM NAAQS will have direct consequences on counties that cannot attain 9.0 ug/m^3, the lower NAAQS will impact all utilities seeking to construct new generation projects or modify existing permits if modeling is required to demonstrate compliance with the lower $PM_{2.5}$ standard. Compliance may be difficult to show in areas that already have higher background PM concentrations, even if the project has only minimal increases of $PM_{2.5}$. Big Rivers is aware of the revised standard and will take it into account should the cooperative initiate any air permitting projects that require NAAQS modeling.

5.5 Clean Air Regulations – Regional Haze Rule

The Regional Haze Rule ("RHR") focuses on visibility impacts on pristine areas, such as national parks. The program is organized by review period to determine visibility impacts. This first review targeted Best Available Retrofit Technology ("BART") controls for SO_2, NOx, and PM emissions for large emission sources that commenced operation between 1962 and 1977. Kentucky completed the first planning period, including BART reviews. That evaluation focused primarily on SO_2 controls and post-combustion NOx controls.

The program is currently in its second planning period, which focuses on reasonable progress. On August 30, 2022, EPA published the "Finding of Failure to Submit Regional Haze State Implementation Plans for the Second Planning Period" ("RHR Finding"). The RHR Finding determines that 15 states, including Kentucky, failed to submit Regional Haze SIPs for the second planning period by July 31, 2021. It established the two-year deadline of August 30, 2024, for EPA to promulgate a federal implementation plan ("FIP") for these states to address the visibility protection requirements of the CAA.

Kentucky's Regional Haze Plan considers the visibility impacts at Mammoth Cave National Park, which is the Commonwealth's only Class I area, as well as visibility impacts on Class I areas in neighboring states. On December 3, 2025, Kentucky submitted its final Regional Haze SIP revision for the second planning period. The Kentucky Division for Air Quality ("KDAQ" or the "Division") initially selected two Kentucky sources, Tennessee Valley Authority's Shawnee Fossil Plant and the D.B. Wilson Station, for a four-factor analysis. As to D.B. Wilson, KDAQ found that Big Rivers installed an advanced wet flue gas desulfurization ("WFGD") control device on Unit 1 that became operational in November 2022. Thus, the Division determined that Wilson is effectively controlled and did not ultimately require Big Rivers to perform a four-factor analysis for Wilson Station. As of July 21, 2026, EPA has not responded to Kentucky's SIP submission.

5.6 Coal Combustion Residuals

Coal Combustion Residuals ("CCR") are residues from the combustion of coal and include fly ash, bottom ash, and scrubber waste. EPA published the final rule regulating the disposal of CCR waste in the Federal Register on April 17, 2015 ("CCR Rule"). The rule establishes technical requirements for CCR landfills and surface impoundments under Subtitle D of the Resource Conservation and Recovery Act ("RCRA") 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 portions of EPA's final rule regulating the disposal of CCRs at coal-fired power plants and determined that unlined CCR impoundments are likely to leak. The Court also found that clay-lined impoundments are also not protective. Finally, the Court concluded that the Resource Conservation Recovery Act provides EPA with the authority to regulate both active and inactive CCR units. In so doing, EPA rejected the exemption for legacy ponds as arbitrary and capricious.

In light of the Court's ruling, and in response to other regulatory developments, EPA 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. On May 8, 2024, EPA finalized the Legacy Rule, which also responds, in part, to the D.C. Circuit decision and was effective on November 8, 2024. It is currently in effect. The Legacy Rule creates two new categories of units subject to

CCR Rule: Legacy CCR surface impoundments ("LSIs") and CCR management units ("CCRMUs"). An LSI is "a CCR surface impoundment that no longer receives CCR but contained both CCR and liquids on or after October 19, 2015, and that is located at an inactive electric utility or independent power producer [i.e., that ceased providing power to electric power transmission systems or to electric power distribution systems before October 19, 2015]." The second category, CCRMUs, is "any area of land on which any noncontainerized accumulation of CCR is received, is placed, or is otherwise managed, that is not a regulated CCR unit." The Legacy Rule added alternative closure provisions for CCR units closing by removal. EPA amended the closure-in-place performance standards to apply to all CCR units.

For CCRMUs, the Legacy Rule established a new Facility Evaluation process to identify CCRMUs at active power plants or power plants with an LSI. This process is divided into stages, with two Facility Evaluation Reports. The first, ("FER 1") was to be posted on-line by February 9, 2026, but EPA extended this deadline to February 9, 2027, in light of its reconsideration of the Legacy Rule, discussed *infra*. Largely, LSI compliance deadlines are one year earlier than those for CCRMUs.

EPA, under the Trump Administration, is reconsidering the Legacy Rule. On April 13, 2026, EPA published a Proposed Rule entitled, *Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals from Electric Utilities; Legacy/CCRMU Amendments*. The 2026 Legacy Amendments Rule

proposes revisions that would modify the LSI and CCRMU provisions put in place by the Legacy Rule. EPA offers options to eliminate or narrow the CCRMU category of units; provisions for exempting CCR dewatering structures; and new site-specific compliance pathways for regulated units by a permit, such as groundwater monitoring points of compliance, cleanup levels for corrective action, closure requirements, closure timeframes; and provisions to allow CCR extraction for beneficial use during the post-closure care period. EPA proposed to revise the definition of beneficial use by eliminating the requirement for an environmental demonstration for the non-roadway use of more than 12,400 tons of unencapsulated CCR on land and also offered regulatory exclusions for specific beneficial uses. Finally, EPA suggests revisions to the definition of a CCR storage pile.

Big Rivers has three facilities currently in compliance with the CCR Rule, D.B. Wilson, Coleman, and Sebree Stations, with regulated units as follows:

- D.B. Wilson: Phase 2 Landfill CCR unit
- Coleman: Ash Pond A, B, C, and D LSIs
- Sebree: Green Landfill CCR unit

In its 2020 Environmental Compliance Plan ("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. Closure of the Green Station ash pond is complete, and closure of the Station Two ash pond is complete as of October 2, 2024, and September 30, 2024, respectively.

Wilson Station: 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 is complete. The active Wilson Phase 2 Landfill is monitored in accordance with the CCR Rule. It is presently in assessment monitoring with corrective action pending.

Green Station: Big Rivers operates a special waste landfill located at the Green Station. The Green Landfill is a CCR unit and has existing groundwater monitoring wells used to comply with the CCR requirements. In addition, a former impoundment completed closure by removal activities in August 2024. Big Rivers obtained the completion of closure certification with the Kentucky Department of Environmental Protection, Division of Waste Management ("KDWM") on March 27, 2025. The Green Former Surface Impoundment has remained in detection monitoring from 2016 through 2024 pursuant to 40 Code of Federal Regulations ("CFR") §257.94. Since no CCR constituents detected had statistically significant increases ("SSIs"), assessment monitoring was never triggered from the Green Former Surface Impoundment.

Sebree Station: Reid/HMP&L Pond ("CCR Pond 2') are located at Sebree Station. On October 29, 2024, Big Rivers Electric Corporation received final acceptance of its Clean Closure of the facility from KDWM. It was closed in compliance with the CCR Rule, 40 CFR 257.102(b). Big Rivers is currently evaluating compliance with the Legacy Rule and awaiting the potential revisions to it. Big Rivers has undertaken preparations to timely comply with the Legacy Rule and is monitoring regulatory developments.

Finally, Big Rivers continues to maintain a publicly accessible website[82] that is populated with the reports and studies required to date.

5.7 Effluent Limitations Guidelines

The Effluent Limitations Guidelines ("ELG") regulate the discharge of wastewater from power plants. On November 3, 2015, EPA published the final rule (the "2015 ELG Rule"), which sets effluent limits for arsenic, mercury, selenium, and nitrogen discharged from wet scrubber systems and zero discharge of pollutants in ash transport water. Compliance was dependent on a plant's National Pollutant Discharge Elimination System ("NPDES") permitting cycle but was to occur at least by 2023. However, the U.S. Court of Appeals for the Fifth Circuit remanded a portion of the 2015 ELG Rule to EPA to reconsider legacy wastewater and combustion residual leachate ("CRL") discharge requirements.

[82] CCR Rule Compliance and Data Information is available at https://www.bigrivers.com/sustainable-power.html

A series of EPA rulemakings followed to address the issues on remand. On October 13, 2020, EPA established effluent limits for flue gas desulfurization ("FGD") wastewater and for bottom ash transport water applicable to existing steam electric power generators. Other waste streams were not addressed. The Biden EPA reconsidered this rule. On May 9, 2024, EPA published a final rule, Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Generating Point Source Category (the "2024 ELG Rule") that calls for stringent limitations on a number of wastewater discharge streams, including a zero-discharge standard on FGD wastewater, bottom ash transport water, and CRL. EPA is currently reconsidering the 2024 ELG Rule.

On December 31, 2025, EPA published a final rule extending the 2024 ELG Rule compliance deadlines. On May 13, 2026, the EPA signed a proposed rule to revise the 2024 ELG Rule. The Proposed Rule would revise the ELGs for unmanaged CRL, offer a range of regulatory options based on different known technologies, and identify the EPA's preferred option. Big Rivers is following this rulemaking and the potential impacts on the management of CRL at its facilities.

5.8 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. Refer to Section 4, Regulatory Environment, of Chapter 6 for details on how certain environmental regulations are considered in the modeling.

CHAPTER 6

ELECTRIC INTEGRATION ANALYSIS



6 ELECTRIC INTEGRATION ANALYSIS

6.1. Key Findings and Preferred Resource Strategy

6.1.1 Key Findings

- The Model Optimization Reference Case portfolio is the Preferred Resource Portfolio.[83]
- The Preferred Resource Portfolio not only satisfies MISO resource adequacy requirements but also provides sufficient excess dispatchable and accredited capacity above Big Rivers' forecasted non-coincident summer peak load beginning in 2029 and non-coincident winter peak load beginning in 2032. This surplus capacity is maintained through the remainder of the planning horizon and provides additional resilience against load forecast uncertainty, accreditation changes, and evolving reliability requirements.
- Portfolios that retain and make reliability improvements to Green and Wilson consistently outperform portfolios that retire and replace those resources on a fixed schedule.
- The Fuel Oil Backup Project at Green is selected in every scenario and portfolio evaluated, demonstrating significant reliability, fuel assurance, and winter accreditation benefits.

[83] Responsive to 807 KAR 5:058, Sections 5(4) and 5(5).

- The implementation of reliability projects at Wilson is selected in the Reference Case and Natural Gas Infrastructure Challenges scenarios, preserving a valuable dispatchable resource through the planning horizon.
- Green remains in operation through 2050 in every scenario evaluated.
- The Reference Case and Natural Gas Infrastructure Challenges scenarios produce similar resource planning outcomes, providing confidence in the recommended strategy under the futures considered most likely to occur.
- The Reid CT does not require replacement by a new-build resource. The IRP demonstrates that addition of the Green Fuel Oil Backup Project provides sufficient accredited capacity to maintain reliability, eliminating the need for new-build replacement capacity that would otherwise be required under Kentucky's retirement of dispatchable generation requirements.[84]
- Renewable resources are selected in most scenarios for their economic energy value, but existing dispatchable generation remains critical to maintaining reliability and resource adequacy.

[84] KRS 278.264(2)(a).

- The High Regulatory scenarios achieve lower emissions but at substantially higher cost and with lower dispatchable capacity margins.

6.1.2 Preferred Resource Portfolio

The Preferred Resource Portfolio consists of the following:

- Continued operation of Green through the planning horizon.
- Continued operation of Wilson through the planning horizon.
- Implementation of the Fuel Oil Backup Project at Green.
- Implementation of the reliability projects at Wilson.
- Evaluation of DR pilot programs to justify the deployment of cost-effective DSM programs.
- Future renewable resource additions as economically justified.
- Continued monitoring of load growth, regulatory developments, and market conditions to maintain planning flexibility.

6.1.3 Short-Term Action Plan

- Seek Commission approval of the retirement of the Reid CT.
- Seek a Certificate of Public Convenience and Necessity ("CPCN") for the construction of the Green Fuel Oil Backup Project.

- Implementation of cost-effective DR pilot programs identified through the Market Potential Study.
- Utilize the Green Fuel Oil Backup Project to address near-term capacity needs, including the loss of the Reid CT.
- Monitor evolving MISO resource adequacy requirements, accreditation methodologies, and capacity market developments.
- Reassess future generation additions as load growth, market conditions, and regulatory requirements evolve in future IRPs.

6.2 Objectives[85]

Big Rivers initiated an IRP in collaboration with ACES to reassess long-range strategic resource plans and satisfy the three-year filing requirement for IRPs with the Commission. Big Rivers' 2026 IRP is a comprehensive long-term planning document that outlines how the Company will continue providing reliable, affordable, and lower risk electric service to its members. The IRP models Big Rivers' current supply and demand portfolio, evaluating the potential retirement of the existing coal-fired and natural gas-fired resources while exploring new resource options to meet Member needs. Through capacity expansion modeling, scenario analysis, and sensitivity analysis, this IRP identifies potential strategies that balance cost, reliability, and risk. It also provides guidelines that Big Rivers can use for future planning as market conditions,

[85] Responsive to 807 KAR 5:058, Section 5(1).

regulations, and portfolio priorities evolve. This IRP is designed to comply with the Commission's IRP requirements under 807 KAR 5:058, while positioning Big Rivers to meet evolving resource needs and satisfy statutory requirements related to the retirement of fossil fuel-fired generating units. The plan integrates system forecasting, resource adequacy analysis, policy evaluation, and scenario modeling to form a forward-looking strategy that guides Big Rivers from 2027 through 2050, with 2026 serving as the base year.[86] Key planning items of consideration in this IRP include the following:

- Comparing alternative plans for Green's two natural gas steam turbines, including examining the cost-effectiveness of adding fuel oil backup to the Green units to improve resource fuel availability and MISO winter capacity accreditation.
- Comparing alternative plans for Wilson's coal-combustion steam turbine, including examining the cost-effectiveness of certain reliability projects at Wilson.
- Determining whether a replacement for the Reid CT is needed, due to the unit's catastrophic forced outage.

[86] Net present valued results for Present Value Revenue Requirements (PVRR) and Levelized Generation Cost ($/MWh) are for 2027 through 2050 for full period results and 2027 through 2041 for 15-year results, all reported in 2026 dollars.

6.2.1 Planning Horizon

While Kentucky's IRP process traditionally focuses on a 15-year planning horizon, Big Rivers elected to evaluate resource needs through 2050 to provide a more complete assessment of the long-term impacts of alternative resource strategies. Many of the resource decisions evaluated in this IRP, including major reliability investments, generating unit retirements, and replacement generation additions, have consequences that extend well beyond a 15-year period. Limiting the analysis to the minimum planning horizon could obscure the significant costs, benefits, and reliability impacts that occur later in the life of these long-term assets.

The extended planning horizon is particularly important when evaluating the Fixed Retirement portfolios. Under these portfolios, Green is assumed to retire in 2039, and Wilson is assumed to retire in 2045. A 15-year study period would capture the retirement of Green but would largely fail to capture the retirement of Wilson and the substantial replacement resource investments required to maintain reliability following that retirement. By extending the analysis through 2050, the IRP captures the full cost and operational impacts associated with replacing both generating stations, allowing for a more meaningful comparison between the Fixed Retirement and Model Optimization approaches.[87]

[87] The Model Optimization approach allows the IRP planning model to optimally select retirements for Green (any time after 2030) and Wilson (any time after 2032) based on cost effectiveness.

At the same time, recognizing the importance of the traditional 15-year planning horizon, Big Rivers presents both 15-year and full-study-period results where practical and meaningful. This approach provides stakeholders with visibility into near- and medium-term planning outcomes while also ensuring that long-term resource decisions are evaluated over a timeframe sufficient to capture their full economic and reliability consequences. As a result, the 2027 through 2050 planning horizon provides a more comprehensive assessment of alternative resource strategies while continuing to support comparisons over the traditional 15-year planning period.

6.3 Encompass Planning Model

ACES utilized EnCompass, a long-term capacity expansion and production cost simulation model, to develop Big Rivers' IRP. EnCompass is an industry-recognized resource planning platform that evaluates alternative resource strategies by simultaneously optimizing generation investments, retirements, market transactions, and operational decisions over an extended planning horizon. The model is designed to identify least-cost resource portfolios while satisfying a wide range of constraints, including forecasted load requirements, MISO resource adequacy obligations, reliability criteria, fuel availability considerations, environmental requirements, and other planning assumptions.

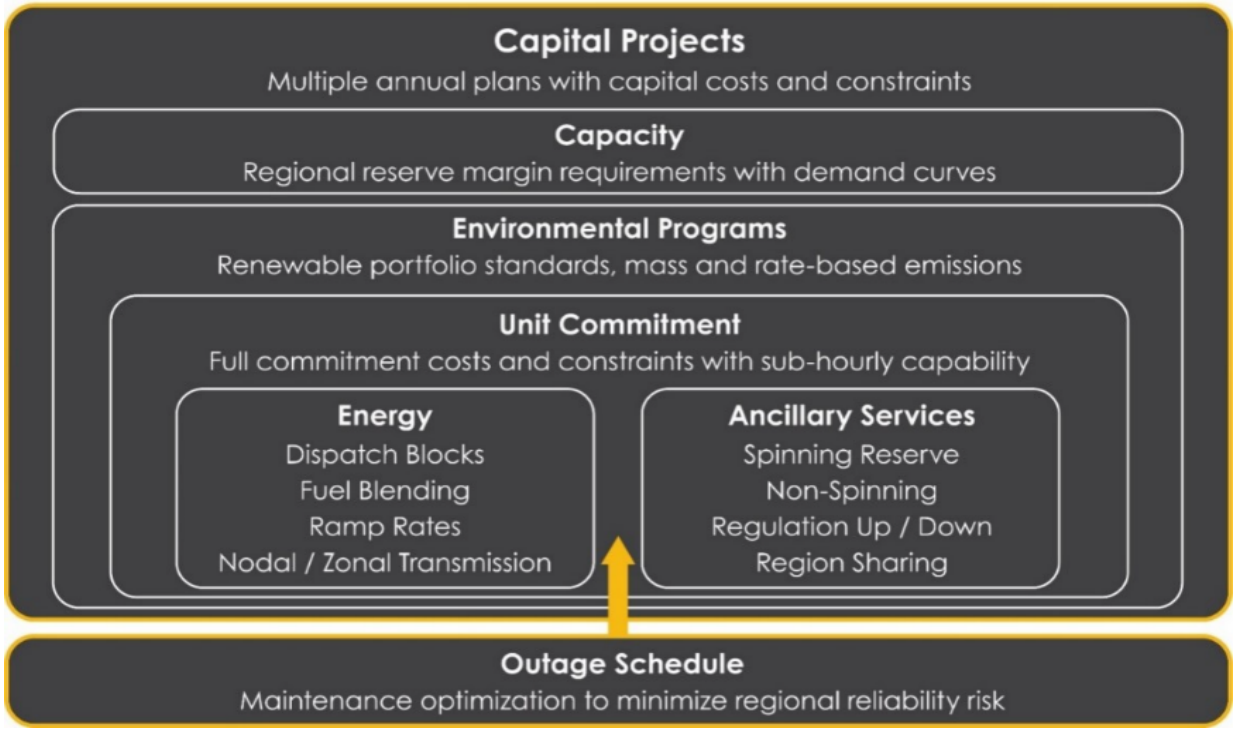
The IRP analysis was performed in two integrated stages. First, the capacity expansion model evaluated candidate resources and retirement options to identify the least-cost portfolio under each planning scenario. This process

considered renewable generation, battery storage, natural gas generation technologies, market purchases, and targeted investments in Big Rivers' existing resources. The model selected the quantity, timing, and type of resources required to maintain reliability while minimizing total system costs over the planning horizon.

Following the development of each capacity expansion portfolio, an hourly production cost simulation was performed in EnCompass to evaluate portfolio economics and operational performance. These simulations dispatch resources on an hourly basis across a full 8,760-hour year, considering hourly load patterns, renewable generation profiles, fuel prices, market prices, transmission limitations, and unit operating characteristics. This detailed operational modeling allows Big Rivers to evaluate long-term resource selection decisions and how those resources perform under realistic operating conditions. The resulting capacity expansion and production cost outputs form the foundation for the Scenario Analysis, Cross-Scenario Sensitivity Analysis, Stochastic Analysis, and IRP Scorecard Evaluation presented throughout this report. Figure 6.3(a) illustrates the high-level architecture of the EnCompass modeling framework.

Figure 6.3(a)

Encompass Planning Model Overview



6.4 Regulatory Environment[88]

6.4.1 Environmental Protection Agency 111 Greenhouse Gas Rules

As explained in Section 5.1, Clean Air Regulations – Greenhouse Gas Rules, the federal regulatory outlook for greenhouse gas emissions from fossil fuel-fired power plants has changed significantly since EPA finalized the 2024 Carbon Pollution Standards under Section 111 of the Clean Air Act. In June 2025, EPA proposed repealing the power-sector GHG rules, arguing that GHG emissions from fossil fuel-fired power plants do not warrant regulation under Section 111. EPA further reinforced this direction in February 2026 by finalizing rescission of

[88] Responsive to 807 KAR 5:058, Sections 5(6), and 8(5)(f)-(g).

the 2009 Greenhouse Gas Endangerment Finding, which was a foundational element of federal GHG regulation. While these actions do not eliminate all regulatory uncertainty, they indicate that the current federal policy focuses on reducing GHG regulation rather than implementing the 2024 power plant standards. Litigation challenging both the original rules and subsequent repeals is ongoing, and future administrations could pursue alternative regulatory approaches. As a result, the long-term regulatory outlook remains uncertain, particularly over the planning horizon evaluated in this IRP. Given the current federal policy direction, it is reasonable for the Reference Case scenario to assume a repeal or non-implementation of the Section 111 GHG requirements. However, because future carbon regulation remains a plausible risk, Big Rivers also evaluated a High Regulatory scenario that includes a carbon tax and increased natural gas resource costs. Section 6.5.4.2, High Regulatory Environment, includes additional details on this scenario. This scenario appropriately reflects the most likely regulatory outlook in the Reference Case while testing portfolio resilience under a more stringent environmental policy future. Chapter 5 provides detailed information related to the history and status of environmental regulations.

6.4.2 One Big Beautiful Bill Act

The federal One Big Beautiful Bill Act ("OBBBA"),[89] signed on July 4, 2025, introduced a restructuring of federal energy incentives and regulatory programs. OBBBA rolls back several Inflation Reduction Act (IRA) clean energy provisions, accelerates the phase-out of the production tax credit (PTC) and investment tax credit (ITC) for solar and wind, and restructures federal support toward domestic fossil fuel development, mining activity, and firm energy resources. Under OBBBA, solar and wind tax credits end for facilities placed in service after December 31, 2027, with stricter timing requirements and manufacturing-origin rules that further limit eligibility for credits. However, federal incentives for energy storage, hydropower, geothermal, and advanced nuclear technologies remain in place, with storage continuing to qualify for the ITC outlined in the IRA. For Big Rivers' IRP Reference Case, any renewable projects added through 2027 are assumed to receive applicable tax credits, while projects added after 2027 are assumed to not qualify, consistent with current OBBBA statutory language. This assumption provides a conservative representation of long-term federal policy support and reflects the current incentive landscape. The High Regulatory scenario previously mentioned includes a reinstatement of the ITC and PTC for wind and solar through the planning period.

[89] *See* One Big Beautiful Act, Pub. L. No. 119-21(2025), available at https://www.congress.gov/bill/119th-congress/house-bill/1/text .

6.4.3 Kentucky Requirements for Retiring Dispatchable Resources

The 2026 IRP was developed in consideration of Kentucky's statutory requirements governing the retirement and replacement of dispatchable generating resources. Pursuant to KRS 278.264(2)(a), a utility seeking to retire a dispatchable generating unit must generally demonstrate that replacement resources are dispatchable, maintain or improve system reliability and resilience, satisfy applicable reserve margin requirements, and provide comparable capacity value, unless the utility can demonstrate that such capacity value and net capability is not necessary to provide reliable service.

These requirements have important implications for long-term resource planning because Kentucky law distinguishes dispatchable resources from intermittent resources. Under KRS 278.264, wind and solar generation, as well as energy storage resources with less than forty-eight (48) hours of discharge capability, are considered intermittent resources and generally cannot serve as stand-alone replacement resources for retiring dispatchable generation. As a result, dispatchable replacement technologies such as natural gas combined-cycle ("NGCC") units, combustion turbines, reciprocating internal combustion engines ("RICE"), long-duration storage,[90] and existing thermal resources play a critical role in maintaining compliance with Kentucky's statutory standard.

[90] The long-duration storage resource included in this IRP is assumed to be capable of discharging at maximum capacity for 100-hours when dispatched. For purposes of this IRP, Big Rivers assumes this resource would satisfy the dispatchability and reliability considerations reflected in KRS 278.264.

When left unconstrained, all capacity expansion analyses performed in the 2026 IRP resulted in portfolios that were compliant with the Kentucky law outlined in the previous paragraphs, except for the High Regulatory (Carbon Tax) scenario. In this scenario, the model frequently selects renewable resources as replacements for retiring thermal assets due to the carbon tax. To address this outcome, ACES included an additional High Regulatory (Carbon Tax) capacity expansion analysis that requires the model to fully replace Wilson and Green with dispatchable resources that are compliant with Kentucky law.

Additionally, these requirements are particularly relevant to the evaluation of the Reid CT, which became unavailable following the August 2024 mechanical failure. As a dispatchable fossil-fueled generating resource, the Reid CT falls within the scope of KRS 278.264. Consequently, this IRP evaluates not only the system impacts associated with the loss of the Reid CT, but also whether new-build replacement capacity with equivalent capacity value and net capability remains necessary to provide reliable service. Consistent with KRS 278.264(2)(a)4, the IRP specifically examines whether alternative actions, including the Green Fuel Oil Backup Project and cost-effective DSM programs, provide sufficient reliability benefits such that a dedicated replacement resource is no longer required.

6.5 IRP Framework[91]

6.5.1 Framework Overview

Big Rivers' IRP was developed using a multi-layered analytical framework designed to evaluate resource strategies under a wide range of future conditions. The framework combines deterministic scenario analysis, cross-scenario sensitivity testing, stochastic risk assessment, and multi-attribute IRP Scorecard evaluation to provide a comprehensive assessment of potential resource pathways. Together, these analytical tools allow Big Rivers to examine the expected performance of alternative portfolios and their resilience to uncertainty associated with future load, fuel markets, regulatory developments, weather conditions, and technology costs. The resulting framework supports informed decision making by balancing affordability, reliability, risk management, and sustainability considerations over the long-term planning horizon.

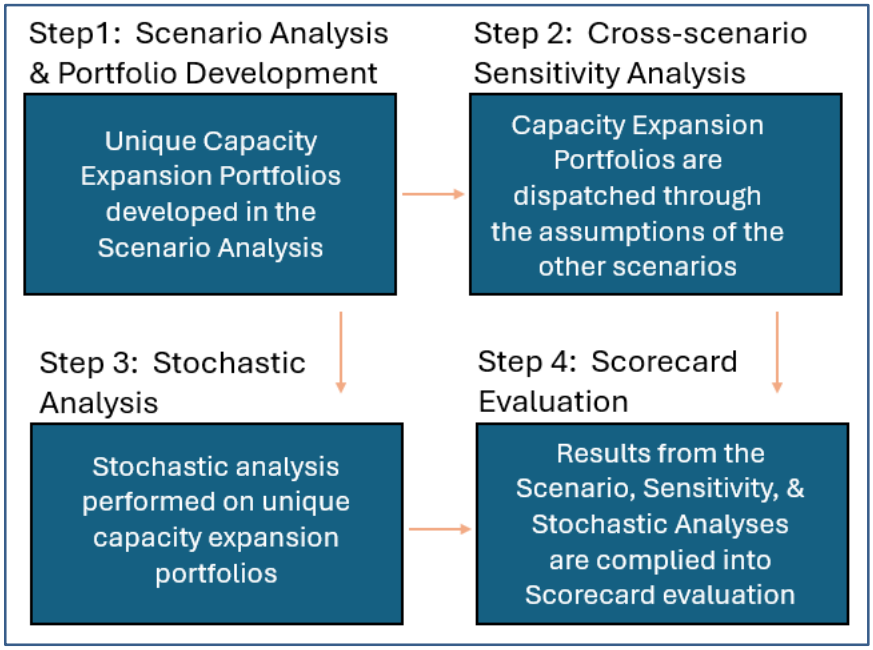
Figure 6.5.1(a) summarizes the analytical framework used to evaluate alternative resource portfolios in the Big Rivers IRP. The process begins with the Scenario Analysis, in which unique capacity expansion portfolios are developed under multiple future scenarios and retirement approaches to identify resource strategies that satisfy load, reliability, and regulatory requirements. These portfolios are then evaluated through a Cross-Scenario Sensitivity Analysis, in which each portfolio is dispatched under the assumptions of the other planning

[91] Responsive to 807 KAR 5:058, Section 8(5)(a)-(g).

scenarios to assess its robustness if future conditions differ from those anticipated during portfolio development. In parallel, a Stochastic Analysis is performed on each unique portfolio to quantify exposure to uncertainty in key drivers, such as weather, load, fuel prices, and market prices. As illustrated in Figure 6.5.1(a), the results of the Scenario Analysis, Cross-Scenario Sensitivity Analysis, and Stochastic Analysis are subsequently integrated into the Scorecard Evaluation, which compares portfolios across affordability, reliability, risk and opportunity, and sustainability metrics. This structured approach ensures that portfolio selection is based on expected performance under a single future and the ability of each portfolio to remain affordable, reliable, and resilient across a broad range of potential future conditions.

Figure 6.5.1(a)

IRP Analysis Roadmap



The following sections outline each of the IRP analyses performed that comprise the IRP framework. Results from these analyses are presented in Section 6.10, IRP Results.

6.5.2 IRP Scenario Analysis and Portfolio Development

The IRP scenario analysis was designed to evaluate the robustness of Big Rivers' resource portfolio across a range of plausible future conditions. The objective was to identify resource strategies that can provide reliable and cost-effective service while remaining resilient to changing market, economic, and regulatory conditions.

The analysis included four scenarios representing a range of expected and alternative future states. The Reference Case and Natural Gas Infrastructure Challenges scenarios represent the most likely futures views, while the Low Load and Natural Gas Price and High Regulatory (Carbon Tax) scenarios represent lower likelihood bookend futures. Together, these scenarios capture the primary uncertainties that could influence resource planning decisions over the study horizon.

6.5.3 Most Likely Scenarios

6.5.3.1 Reference Case

The Reference Case represents Big Rivers' current best view of the future and serves as the baseline planning scenario. As shown in Figure 6.5.4.2(a), the scenario incorporates base load forecasts, base fuel and power market price

assumptions, repeal of EPA GHG regulations, and the continuation of current assumptions regarding generation technology costs and available tax incentives. The Reference Case provides the foundation against which alternative futures are compared.

6.5.3.2 Natural Gas Infrastructure Challenges

The Natural Gas Infrastructure Challenges scenario evaluates a future in which the substantial data center load growth in the U.S. is primarily served by new natural gas resources resulting in constrained natural gas delivery due to potential pipeline development limitations and natural gas transportation constraints. Under this scenario, natural gas supply limitations result in higher natural gas prices, higher wholesale power prices, and increased costs associated with constructing and operating natural gas-fired generation, as shown in Figure 6.5.4.2(a). This scenario tests the value of maintaining resource diversity and reducing dependence on a single fuel source. While the Reference Case serves as the most probable future view, Big Rivers views the Natural Gas Infrastructure Challenges scenario as the second most probable future given the significant demand for natural gas resources in the U.S. to serve data center load growth.

6.5.4 Bookend Scenarios

6.5.4.1 Low Load and Natural Gas Price

The Low Load and Natural Gas Price scenario represents a future characterized by lower-than-expected electricity demand growth and reduced

natural gas prices. The scenario assumes limited data center development in the U.S. and slower overall load growth, resulting in lower demand for new generation resources. Reduced demand leads to lower natural gas prices, lower wholesale power prices, and lower generation development costs, as shown in Figure 6.5.4.2(a). This scenario is the lower-growth, lower-cost bookend of the planning analysis.

6.5.4.2 High Regulatory Environment

The High Regulatory scenario evaluates the impacts of more stringent environmental policies. The scenario assumes implementation of a federal carbon tax, higher permitting and compliance costs for thermal generation resources, and increased system loads driven by electrification and electric vehicle adoption, as shown in Figure 6.5.4.2(a). The scenario also reflects assumptions regarding expanded renewable energy incentives. Big Rivers believes this scenario captures a return to more restrictive national emissions standards or clean energy goals.[92] However, it is still critical to evaluate optimal portfolios and portfolio performance under elevated regulatory risk and higher demand growth scenarios. Due to the carbon tax included in this scenario, the unconstrained model selects portfolios that are not compliant with Kentucky law, which requires retiring dispatchable resources to be replaced with dispatchable resources (outlined in Section 6.4.3, Kentucky Requirements for Retiring Dispatchable Resources). Big Rivers ran an

[92] The carbon tax in the High Regulatory scenario serves as a general proxy for any new federal carbon regulation that generally targets carbon reduction goals consistent with the Paris Climate Accord, like the Section 111 Greenhouse Gas Rules.

additional "High Regulatory Environment" scenario that constrained the IRP model to select only dispatchable resources to ensure compliance with Kentucky law. Figure 6.5.4.2(a) summarizes the assumptions for each of the four primary scenarios.

Figure 6.5.4.2(a)

Scenario Inputs

	Reference Case	Gas Infrastructure Challenges	Low Load and Natural Gas Price	High Regulatory Environment
Big Rivers Load	Base	Base	Low	High
Natural Gas Prices	Base	High	Low	Base
Power Prices	Base	High	Low	Custom Carbon Price
EPA GHG Rules	Repealed	Repealed	Repealed	Carbon Tax
Subsidies (ITC/PTC)	OBBB	OBBB	OBBB	IRA reinstatement + extension
Thermal CapEx	Base	High	Low	High
Renewable CapEx	Base	Base	Low	Base

6.5.5 Green and Wilson Retirement Approaches

Within each scenario referenced in Sections 6.5.1 through 6.5.4, two distinct resource planning approaches were evaluated to assess the implications of alternative retirement strategies for Green and Wilson.

6.5.5.1 Model Optimization Approach

Under the Model Optimization approach, the capacity expansion model was permitted to determine the economically optimal timing for retirement and replacement of Green and Wilson. Retirement dates were not fixed, rather they are selected by the model based on cost effectiveness; however, retirements could

not occur earlier than December 31, 2030, for Green and December 31, 2032, for Wilson. These staggered retirement thresholds were intended to provide sufficient time to develop and procure replacement resources, recognizing that the simultaneous retirement of both units would create a substantial capacity shortfall that would be challenging to replace all at once.

This approach allows the model to identify the timing at which retirement and replacement or continued investment in the resource become economically justified based on the specific conditions represented in each scenario. As a result, retirement or continued investment decisions are integrated into the overall resource optimization process alongside decisions related to new generation additions, market purchases, and system reliability requirements.

6.5.5.2 Fixed Retirement Approach

The Fixed Retirement approach was developed to evaluate a transition away from the existing thermal fleet at the units' current effective estimated end of life. Under this approach, the assumption is to retire and replace Green by December 31, 2039, and retire and replace Wilson by December 31, 2045.

The analysis isolates the impacts of planned retirement decisions and allows comparison to the economically optimized portfolios. This approach provides insight into the costs, resource requirements, and operational implications associated with a defined retirement schedule.

Figure 6.5.5.2(a) provides the Scenario matrix showing both modeling approaches with each scenario, including the additional High Regulatory scenario that complies with Kentucky law. Results included in the Figure will be discussed in Section 6.10.1, Scenario Analysis Results.

Figure 6.5.5.2(a)

Scenario Analysis Matrix

		Reference Case*	Natural Gas Infrastructure Challenges*	Low Load and Natural Gas Prices*	High Regulatory (Carbon Tax)	High Regulatory (Carbon Tax) Kentucky Law Compliant
Levelized Generation Cost ($PVRR/Load MWh) 2027-2050	**Model Optimization** Earliest Green can Retire December 31, 2030 Earliest Wilson can Retire December 31, 2032	$68.89 No Green and Wilson Retirement	$75.64 No Green and Wilson Retirement	$63.33 No Green Retirement; Wilson 2039	$102.26 No Green Retirement; Wilson 2032	$103.73 No Green Retirement; Wilson 2032
	Fixed Retirements Retire and Replace Green December 31, 2039 Retire and Replace Wilson December 31, 2045	$75.33 Green 2039; Wilson 2045	$85.63 Green 2039; Wilson 2045	$64.66 Green 2039; Wilson 2045	$116.89 Green 2039; Wilson 2045	$116.56 Green 2039; Wilson 2045

6.5.6 Cross-Scenario Sensitivity Analysis

To evaluate portfolio robustness, each optimized resource plan was dispatched under the assumptions of all planning scenarios rather than only the scenario in which it was developed. This Cross-Scenario Sensitivity Analysis allows the IRP to evaluate how portfolios perform if actual future conditions differ from the assumptions used during resource selection. The resulting matrix of outcomes shown in Figure 6.5.6(a) provides insight into portfolio resilience, identifies exposure to adverse future conditions, and quantifies the economic implications of uncertainty in long-term load growth, fuel prices, market prices, and regulatory requirements. By examining portfolio performance across multiple

futures, the sensitivity analysis supports selection of resource strategies that balance cost and risk under a broad range of possible outcomes. Results included in the figure will be discussed in Section 6.10.2, Cross-scenario Sensitivity Analysis Results.

Figure 6.5.6(a)

Cross-Scenario Sensitivity Analysis Matrix

Model Optimization	Price Sensitivities ->			
Portfolios ↓	Reference Case	Natural Gas Infrastructure Challenges	Low Load and Natural Gas Prices	High Regulatory (Carbon Tax)
Reference Case	$68.89	$75.67	$65.49	$128.02
Natural Gas Infrastructure Challenges	$70.63	$75.64	$68.32	$126.76
Low Load & Gas Prices	$74.06	$91.34	$63.33	$113.83
High Regulatory (Carbon Tax)	$91.71	$95.61	$79.77	$102.26
High Regulatory (Carbon Tax) Kentucky Law	$93.17	$97.22	$81.47	$103.73
Fixed Retirement	Price Sensitivities -->			
Portfolios ↓	Reference Case	Natural Gas Infrastructure Challenges	Low Load & Gas Prices	High Regulatory (Carbon Tax)
Reference Case	$75.33	$86.73	$68.46	$125.91
Gas Infrastructure Challenges	$76.23	$86.21	$70.37	$129.34
Low Load & Gas Prices	$70.95	$80.83	$64.66	$125.19
High Regulatory (Carbon Tax)	$90.40	$81.21	$84.45	$116.89
High Regulatory (Carbon Tax) Kentucky Law	$89.00	$80.97	$83.29	$116.55

6.5.7 Stochastic Analysis

In addition to the deterministic scenario analysis, Big Rivers' IRP included a stochastic analysis to evaluate the potential range of future cost and reliability outcomes associated with each optimized resource portfolio. While the scenario analysis examines a limited number of discrete future states, the stochastic analysis captures the variability and uncertainty within those futures by simulating a broad range of weather-driven market conditions.

The stochastic analysis was performed using ACES' Weather-Driven Stochastics methodology, which uses machine learning techniques to model the relationships between weather variables and wholesale power prices, power price basis differentials, natural gas prices, system load, and intermittent generation. For each optimized portfolio from the scenario analysis, 100 correlated hourly simulations were generated to represent a range of plausible future operating conditions. A key benefit of this approach is that it preserves the historical relationships among these variables. For example, extreme weather conditions often affect electricity demand, fuel prices, market prices, and renewable generation simultaneously. By preserving these relationships within each simulation, the analysis provides a more realistic range of potential portfolio outcomes than evaluating each variable independently. The resulting simulations produce a distribution of portfolio costs rather than a single expected value. This distribution is used to evaluate expected portfolio performance and the range of potential outcomes. Probability-based metrics derived from the distribution

include the expected (mean) portfolio cost and percentile measures that quantify downside risk and upside opportunity.

6.5.7.1 Relationship to the IRP Scorecard

The stochastic results are incorporated into the IRP Scorecard through the Opportunity and Risk metrics. The Opportunity (5th percentile present value of revenue requirements ("PVRR")) metric represents the portfolio cost at the 5th percentile of simulated outcomes and reflects the potential benefit under favorable combinations of weather, market prices, fuel prices, and system conditions. The Risk (95th percentile PVRR) metric represents the portfolio cost at the 95th percentile of simulated outcomes and reflects the potential cost exposure under unfavorable combinations of weather, market prices, fuel prices, and system conditions. Together, these metrics characterize the range of potential portfolio outcomes and provide insight into the uncertainty surrounding future costs. By evaluating expected portfolio costs and the distribution of simulated outcomes, the stochastic analysis provides additional insight into portfolio risk, cost variability, and resilience under uncertain future conditions.

6.5.8 Scorecard Evaluation

The IRP Scorecard was developed as a structured decision-support framework to compare alternative resource portfolios across affordability, reliability, risk and opportunity, and sustainability objectives. The scorecard provides a consistent evaluation under common market, load, and operational

assumptions, allowing differences in performance to be attributed to the resource mix and operating characteristics of each portfolio. As summarized in Figure 6.5.8.1(a), the scorecard incorporates a balanced set of metrics designed to evaluate the cost, reliability, risk, and environmental tradeoffs associated with alternative resource strategies.

6.5.8.1 Incorporation of Stochastic Results into the Scorecard

The IRP Scorecard incorporates deterministic and stochastic affordability metrics. Affordability comparisons are based on each portfolio's levelized generation cost under the common Reference Case market assumptions. Using a common set of assumptions ensures affordability differences are attributable to portfolio composition rather than differences in load, fuel prices, or market conditions.

To evaluate portfolio risk, results from the stochastic analysis were incorporated into the IRP Scorecard. For each portfolio, the difference between the expected stochastic outcome and the 5th and 95th percentile outcomes were calculated and converted to an equivalent $/MWh adjustment. These adjustments were then applied to the deterministic Reference Case affordability metric to estimate upside opportunity and downside risk while maintaining a consistent basis for comparison.

Although the stochastic simulations were developed using each portfolio's underlying assumptions, the resulting adjustments primarily reflect each

portfolio's relative exposure to uncertainty in market prices, fuel prices, load, weather, and renewable generation. Applying these adjustments to the common Reference Case affordability metric allows the relative risk characteristics of each portfolio to be incorporated into the Scorecard while maintaining a consistent comparison of portfolio affordability.

Figure 6.5.8.1(a)

Scorecard Metrics

Category	Metric	Description
Affordability Evaluates the relative cost impact of each portfolio.	15-Year Levelized Generation Cost ($/MWh 2027-2041)	Measures generation-related costs normalized by energy served over the 15-year planning horizon.
	Full Study Levelized Generation Cost ($/MWh 2027 - 2050)	Measures generation-related costs normalized by energy served over the full study period to capture long-term impacts of resource decisions.
	15-Year PVRR ($MM 2027 - 2041)	Measures generation-related costs over the 15-year planning horizon.
	Full Study PVRR ($MM 2027 - 2050)	Measures generation-related costs over the full study period to capture long-term impacts of resource decisions.
Reliability Evaluates the ability of each portfolio to meet future system demand using dispatchable generation resources consistent with Kentucky law.	Dispatchable Capacity/2046 Winter Peak	Compares total installed dispatchable capacity to projected winter peak demand and indicates overall capacity sufficiency.
	Firm Dispatchable Capacity/2046 Winter Peak	Compares MISO-accredited dispatchable capacity to projected winter peak demand and provides a more conservative measure of resource adequacy.
Risk and Opportunity Evaluates market exposure, cost	P5 Stochastic Cost Outcome ($/MWh 2027 – 2025)	Represents a favorable cost outcome and quantifies potential upside opportunity.

Category	Metric	Description
uncertainty, and potential upside and downside outcomes.	P95 Stochastic Cost Outcome ($/MWh 2027 – 2025)	Represents an adverse cost outcome and quantifies potential downside risk.
Sustainability Evaluates the environmental performance of each portfolio.	Total CO2 Emissions (MM tons Planning Horizon)	Measures cumulative carbon dioxide emissions across the planning horizon.

No single scorecard metric determines the preferred portfolio. Rather, the scorecard is used in conjunction with the Scenario Analysis, Cross-Scenario Sensitivity Analysis, and Stochastic Analysis to evaluate portfolio tradeoffs and identify resource strategies that provide the most balanced combination of affordability, reliability, risk management, and sustainability. The results of the IRP Scorecard Evaluation are presented in Section 6.10.4, Scorecard Evaluation.

6.6 Load Forecast[93]

Big Rivers' load forecast reflects the expected electricity requirements of its member distribution cooperatives, which serve a diverse mix of residential, commercial, agricultural, and industrial customers. These load projections form the foundation of the resource planning process by directly influencing capacity requirements, resource adequacy assessments, and the timing of future resource additions and retirements.

[93] Responsive to 807 KAR 5:058, Sections 8(4)(a)(1) and 8(4)(b)(1).

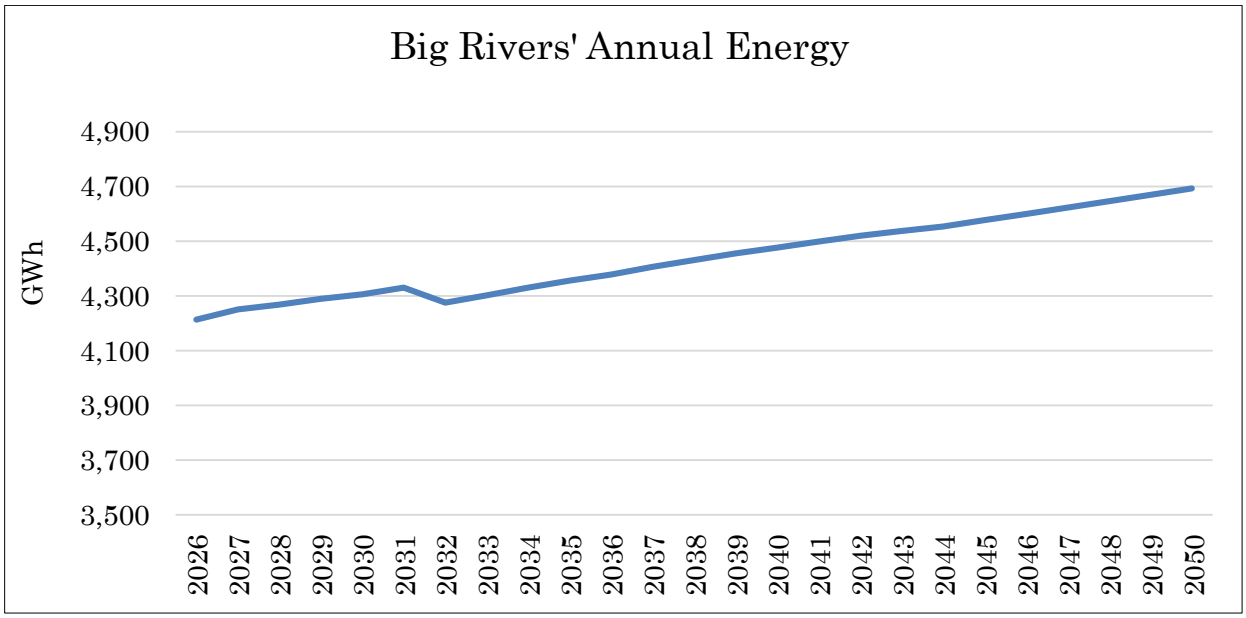
For purposes of discussing Big Rivers' load forecast and capacity planning requirements, it is helpful to distinguish among the following terminology for peak demand used herein:

- **Big Rivers Coincident Peak (CP):** The maximum demand of the Big Rivers system, without regard to when the MISO system peak occurs.
- **Big Rivers MISO Coincident Peak (CP):** Big Rivers' demand at the time of the applicable MISO system peak. This measure is used in determining Big Rivers' capacity planning requirements.

As shown in Figure 6.6(a), annual energy requirements are projected to increase steadily throughout the planning horizon, increasing from approximately 4,200 GWh in 2026 to nearly 4,700 GWh by 2050, representing an average annual increase of approximately 0.5% over the study period. A temporary decrease in forecasted energy requirements occurs in 2032 and is attributable to a change in one of Big Rivers' industrial load contracts that reduces the portion of the customer's load served.

Figure 6.6(a)

Big Rivers' Annual Energy Requirement Forecast



Consistent with the annual energy forecast, seasonal Big Rivers Coincident Peak demand is also expected to increase over time, as shown in Figure 6.6(b). Winter peak demand increases from approximately 741 MW in 2026 to 776 MW by 2050, while summer peak demand increases from approximately 752 MW to 809 MW over the same period. Like the energy forecast, summer and winter peak demand reflect a one-time reduction in 2032 associated with the industrial contract change before gradually increasing. Because winter represents Big Rivers' most constrained operating season and serves as the basis for capacity planning, the projected increase in winter peak demand is a key driver of the resource adequacy and capacity expansion analyses presented throughout this IRP.

Figure 6.6(b)

Big Rivers' Annual Seasonal Big Rivers Coincident Peak Forecast

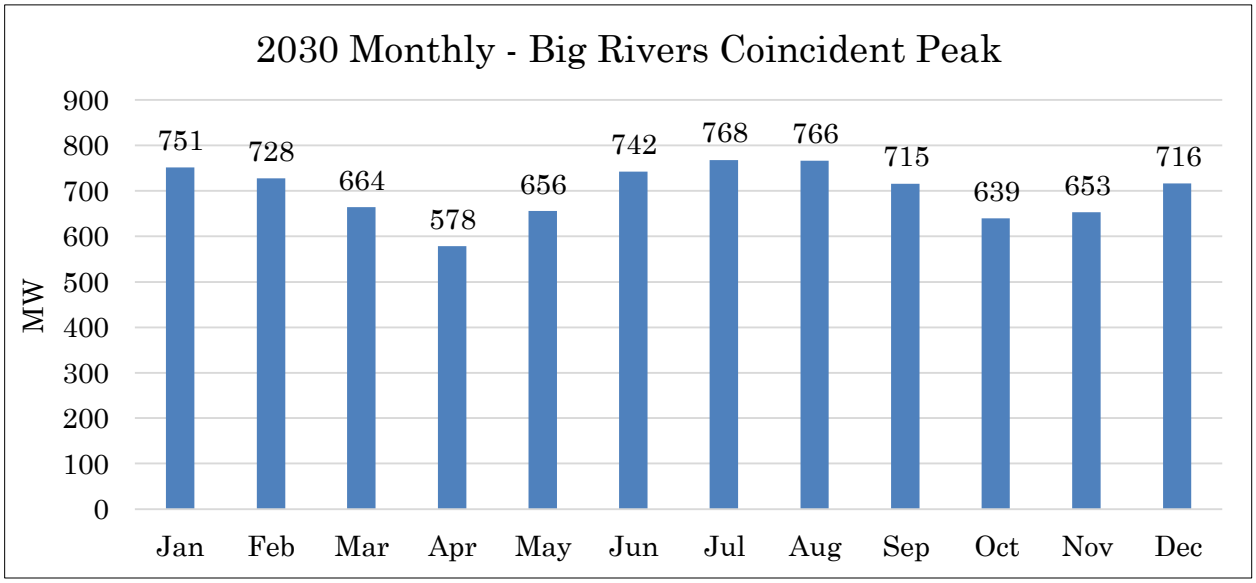
Big Rivers' Seasonal Coincident Peak (MW)		
Year	Summer	Winter
2026	752.4	741.1
2027	758.4	745.2
2028	761.5	747.3
2029	765.1	749.7
2030	767.5	751.1
2031	771.7	754.1
2032	742.9	724.2
2033	747.2	726.8
2034	751.8	729.8
2035	755.9	732.3
2036	759.2	734.2
2037	763.7	737.3
2038	767.5	739.9
2039	771.3	742.6
2040	774.5	744.8
2041	777.8	747.2
2042	780.9	749.7
2043	783.4	751.6
2044	785.5	753.2
2045	789.4	757.0
2046	793.4	760.8
2047	797.4	764.6
2048	801.3	768.4
2049	805.4	772.3
2050	809.4	776.1

While Big Rivers remains a summer-peaking system, Figure 6.6(c) illustrates that winter demand also remains significant, with projected monthly peaks in 2030 ranging from approximately 578 MW in April to a maximum of 768 MW in July. After including the Midcontinent Independent System Operator

(MISO) PRM, winter becomes Big Rivers' most constrained operating season and serves as the basis for capacity planning. Growth in winter peak demand is a key driver of the resource adequacy and capacity expansion analyses presented throughout this IRP.

Figure 6.6(c)

Big Rivers' 2030 Monthly Coincident Peak Load Forecast



Please see Chapter 3, Load Forecast and Appendix A, for a comprehensive discussion of the load forecast.

6.7 Existing Resources and System Description[94]

6.7.1 Existing Resources[95]

Big Rivers' existing resource portfolio is comprised of a diverse mix of thermal, hydroelectric (hydro), and solar generation resources that collectively provide the energy, capacity, and operational flexibility necessary to reliably serve member load. As summarized in Table 6.7.1(a), the portfolio includes Green Unit 1 (205 MW/231 MW), Green Unit 2 (223 MW), Wilson (417 MW), the Southeastern Power Administration (SEPA) hydro power contract (178 MW), and the Unbridled Solar facility contract (160 MW). Together, these resources provide a balanced combination of dispatchable generation and renewable energy that supports reliable system operations.

The foundation of the portfolio is the Company's dispatchable thermal fleet, consisting of the 428 MW Green Station and the 417 MW Wilson Station. These resources provide the firm capacity, operating flexibility, and reliability attributes needed to meet peak demand and maintain system reliability. In addition, Big Rivers receives a 178 MW allocation of hydro power from SEPA, which provides a stable source of renewable energy and capacity through 2050. Big Rivers also has a contract to purchase all of the output of the 160 MW Unbridled Solar facility,

[94] Responsive to 807 KAR 5:058, Section 8(2)-(4).

[95] Responsive to 807 KAR 5:058, Section 8(3)(a)-(d).

which further diversifies the portfolio by supplying emissions-free generation and reducing reliance on conventional resources during daylight hours.

As shown in Table 6.7.1(a), the existing resource portfolio includes approximately 1,005 MW of owned thermal generating capacity, 160 MW of contracted solar capacity, and 178 MW of SEPA federal hydro capacity. This existing fleet serves as the foundation for the IRP and establishes the starting point for evaluating future reliability investments, resource additions, and retirement decisions. The capacity expansion, scenario, and portfolio analyses discussed throughout this report assess how this resource base may evolve to meet Big Rivers' future energy and capacity requirements.

Figure 6.7.1(a)

Big Rivers' Existing Resources Overview

Existing Resources					
Resource	**Resource Type**	**Technology Type**	**COD**	**Retirement Date**	**Nameplate Capacity (MW)**
Green Unit 1	Thermal	Natural Gas Steam Turbine (ST)	1979	N/A	205, 231 (uprate in March 2029)
Green Unit 2	Thermal	Natural Gas ST	1981	N/A	223
Wilson	Thermal	Coal ST	1984	N/A	417
SEPA	Hydro	Hydro	1963	N/A	178
Unbridled PPA	Solar	Solar	2023	2043	160

Big Rivers evaluates the capacity contribution of its existing resources using the MISO Seasonal Resource Adequacy, Loss of Load Expectation (LOLE), and Direct Loss of Load (DLOL) constructs and actual/forecasted resource

performance as discussed in Section 6.7.3. Under the current Seasonal Accredited Capacity (SAC) framework (2026 through 2027), Big Rivers' thermal resources receive higher accreditation values in summer, reflecting availability performance during peak summer periods. Summer SAC values for these units range from approximately 75% to 85% of respective Installed Capacity (ICAP), reflecting performance during traditional summer peak conditions. Winter accreditation for Green is negatively impacted due to fuel supply constraints during high winter natural gas demand periods. Green Unit 1 and Green Unit 2 receive winter SAC values of approximately 79% and 49%, respectively. Wilson receives a winter SAC value of 74%.

As expected, with the transition to the DLOL framework (2028 and beyond), the accredited capacity of resources generally declines, most notably for Green due to winter fuel availability concerns and MISO solar resource accreditation method changes. Under DLOL, the winter accreditation of the Green units decreases significantly, with Green Unit 1 and Green Unit 2 declining to approximately 35% and 36%, respectively. This reduction reflects MISO's expectations and explicit consideration of natural gas supply availability and deliverability risks during winter events. In contrast, Wilson's accreditation remains relatively robust, increasing modestly to approximately 78% in winter and 87% in summer, reflecting the unit's firm fuel supply and performance improvement through continued investments and expected availability during MISO resource adequacy Tier II Hours.

Similarly, the SEPA hydro allocation experiences a modest reduction in accredited capacity under DLOL, declining from approximately 95% (winter SAC) to 84% (winter DLOL) and from 98% to 83% in summer. This reduction reflects the probabilistic treatment of hydro availability under varying system and hydrological conditions and proposed changes in how MISO accredits external resources. The Unbridled Solar facility exhibits a more pronounced decline in accreditation under DLOL, with winter accreditation effectively reduced to 0% and summer accreditation reduced to approximately 3%. This outcome reflects the limited contribution of solar generation during peak risk periods identified in the DLOL and LOLE frameworks.

Overall, the transition from SAC to DLOL results in a shift in capacity value toward resources that demonstrate high availability and performance during times of system reliability stress. For Big Rivers, this transition reduces the accredited capacity of certain resources – particularly gas-fired and solar generation – while reinforcing the relative reliability contribution of resources with firm fuel supply and dispatchability. These changes are a key consideration in resource planning, as they directly affect PRMs, capacity procurement requirements, and the evaluation of potential resource investments and operational enhancements.

Figure 6.7.1(b)

Big Rivers' MISO Accreditation of Existing Resources

Existing Resources								
Resource	Technology Type	Maximum Capacity (MW)	Winter Average SAC 2026 to 2027	Winter Average DLOL 2028 to 2050	Winter Average DLOL 2028 to 2050 With Green Fuel Oil Backup	Summer Average SAC 2026 to 2027	Summer Average DLOL 2028 to 2050	Summer Average DLOL 2028 to 2050 With Green Fuel Oil Backup
Green Unit 1	Natural Gas Steam Turbine (ST)	205, 231*	79%	35%	66%	85%	82%	84%
Green Unit 2	Natural Gas ST	223	49%	36%	67%	83%	81%	83%
DB Wilson	Coal	417	74%	78%	N/A	75%	87%	N/A
SEPA	Hydro	178	95%	84%	N/A	98%	83%	N/A
Unbridled	Solar	160	5%	0%	N/A	50%	3%	N/A

6.7.2 Demand Side Management Resources[96]

Big Rivers evaluated DSM opportunities through an MPS conducted by GDS, as discussed in Chapter 4 of this report. Based on the results of that study, Big Rivers selected a portfolio of cost-effective demand response and energy efficiency programs for inclusion in the IRP. The selected DSM portfolio includes residential, commercial, and industrial energy efficiency measures, as well as demand response programs, and was modeled as a fixed resource in the capacity expansion analysis.

The IRP assumes DSM program expenditures of approximately $1 million annually beginning in 2027, with modest escalation over time driven primarily by

[96] Responsive to 807 KAR 5:058, Sections 8(2)(b) and 8(3)(e).

the demand response component of the portfolio. The selected programs are projected to provide meaningful reductions in peak demand and energy consumption. Demand response savings increase to approximately 17 MW of peak load reduction by 2033 before gradually declining over the remainder of the planning horizon. Energy efficiency savings increase steadily throughout the study period, reaching approximately 23 GWh of annual energy savings by 2040.

Consistent with industry practice, the projected DSM impacts were incorporated directly into the resource planning analyses. As a result, the selected DSM programs contribute to reducing future energy requirements, reducing peak demand, and deferring the need for additional generation resources while providing cost-effective benefits to Big Rivers and its member systems.[97]

6.7.3 PRM and Coincidence Factor Assumptions[98]

The MISO resource adequacy construct, including the SAC and DLOL frameworks, establishes PRM requirements based on Big Rivers' actual peak coincident to MISO's peak hour. Because Big Rivers' seasonal peak demand does not always occur at the same time as MISO's system peak, MISO's PRM requirements cannot be applied directly to Big Rivers' forecast peak loads.

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[97] Big Rivers and GDS Associates used the Market Potential Study ("MPS") to screen the broader universe of potential EE and DR measures to realistic, cost-effective program-level resources for inclusion in the IRP portfolios. This screening relied primarily on the Total Resource Cost ("TRC") test to determine cost-effectiveness; therefore, the EE and DR resources evaluated in the IRP represent screened program potential rather than the full technical or economic potential identified in the MPS.

[98] Responsive to 807 KAR 5:058, Section 8(5)(d).

Accordingly, Big Rivers developed season-specific coincident peak factors using the methodology MISO recommends translating MISO's requirements into an equivalent PRM appropriate for its system.

As shown in Figure 6.7.3(a), the analysis begins with MISO's published seasonal PRM assumptions under the SAC and DLOL frameworks. Big Rivers then evaluated the historical relationship between its seasonal peak demand and the Company's load at the time of MISO's seasonal peak using MISO's recommended methodology. This relationship was used to calculate a seasonal coincident peak factor, which reflects the percentage of Big Rivers' peak demand that is expected to occur simultaneously with the MISO system peak. Because Big Rivers' seasonal peaks are generally higher than its coincident peak obligations, the coincident peak factors are less than 100% in each season.

The final reserve margin adjustments shown in Figure 6.7.3(a) represent the reserve requirements applied within the IRP modeling after accounting for the coincident peak relationship. These adjusted values were used in conjunction with seasonal resource accreditation values to determine the accredited capacity required to satisfy MISO's resource adequacy requirements. As a result, the reserve margin assumptions used in the IRP are lower than MISO's published system-wide PRMs because they reflect Big Rivers' actual peak coincident to MISO's peak hour.

It is also important to note that the transition from SAC to DLOL affects both sides of the resource adequacy equation. Under DLOL, the effective PRM

requirement generally declines; however, the accredited capacity assigned to several resources also declines. Consequently, the negative reserve margin adjustments shown in Figure 6.7.3(a) should not be interpreted as creating additional excess capacity or improving Big Rivers' capacity position. In simple terms, the capacity requirement becomes smaller, but the amount of capacity credited to certain resources also becomes smaller. Therefore, the ultimate impact on Big Rivers' resource adequacy position depends on the combined impact of the reserve requirement and the accreditation assigned to the resources within the portfolio.

Figure 6.7.3(a)

MISO PRMs and Coincident Peak Factors

Planning Year (PY) 2025/2026 to PY 2027/2028			
	SAC PRM	Big Rivers' Coincident Peak Factor (CPF)	Final Big Rivers' Reserve Margin Adjustment for CPF
Summer	7.90%	94.82%	2.31%
Fall	14.90%	95.26%	9.45%
Winter	18.40%	93.73%	10.98%
Spring	25.30%	94.54%	18.46%
PY 2028/2029 and Beyond			
	DLOL PRM	Big Rivers' CPF	Final Big Rivers' Reserve Margin Adjustment for CPF
Summer	4.40%	94.82%	-1.00%
Fall	-10.40%	95.26%	-14.65%
Winter	1.50%	93.73%	-4.86%
Spring	-2.50%	94.54%	-7.82%

The reserve margin and accreditation values used in the IRP are planning assumptions based on the information available when the model was developed;

they are not forecasts of the final values MISO will establish for every future Planning Year. MISO will continue to update its seasonal PRM, PRM Requirement (PRMR), and accreditation values as load forecasts, resource mix, system risk, and resource performance data change. Big Rivers will monitor those developments and update the applicable assumptions before making any material resource retirement, acquisition, or reliability investment decision. This approach maintains a consistent physical reliability standard while avoiding premature capital commitments based solely on indicative values.

6.7.4 Current Summer and Winter Firm Capacity Position[99]

Big Rivers' summer capacity position, shown in Figure 6.7.4(a), reflects the ability of its existing resource portfolio, discussed earlier in this section, to meet forecasted summer coincident peak demand and associated PRM requirements across the study horizon.[100] The analysis assumes the continued operation of Green and Wilson through 2050, which together provide the majority of accredited summer capacity. Under summer conditions, Green demonstrates relatively strong accreditation and operational performance, complementing the firm capacity provided by Wilson. Additional contributions from the SEPA hydro

[99] Responsive to 807 KAR 5:058, Section 8(4)(a).

[100] For existing resources, Big Rivers used MISO-indicated resource-specific DLOL accreditation values derived from off-PY 2026/2027 accredited capacity performance. Resource-specific performance factors were then calculated relative to the applicable MISO class average to develop a forward-looking estimate of seasonal accreditation based on each resource's historical performance, expected future resource reliability characteristics, and MISO provided DLOL class average forecasts and indictive resource-specific values.

resources, the Unbridled Solar facility, and DSM programs further support the summer capacity position and provide portfolio diversity during peak load conditions.

The results indicate that Big Rivers [redacted] The IRP modeling framework enables the economic selection of new resources beginning in 2031 to maintain resource adequacy and optimize long-term system costs. This approach reflects the comparatively stronger performance of the existing resource portfolio during summer periods, combined with a phased strategy that leverages existing assets and evaluates future resource additions as system needs evolve and market conditions develop.

Figure 6.7.4(a)

Big Rivers' Summer Capacity Position[101]



Big Rivers' winter capacity position, shown in Figure 6.7.4(b), reflects the ability of its existing resource portfolio to meet forecasted winter coincident peak demand and associated PRM requirements over the study horizon. The starting position assumes the continued operation of Green and Wilson through 2050, which together provide the majority of Big Rivers' accredited winter capacity. The IRP will optimize possible early retirement dates of these units in different scenarios based on cost effectiveness, and Green will be allowed to retire as early

[101] "Peak" in Figure 6.7.4(a) refers to Big Rivers CP and "Peak + Reserves" refers to Big Rivers MISO CP + the Planning Reserve Margin which makes this the Planning Reserve Margin Requirement used as the target for capacity planning.

as December 31, 2030 and Wilson as early as December 31, 2032. These staggered retirement thresholds were intended to provide sufficient time to develop and procure replacement resources, recognizing that the simultaneous retirement of both units would create a substantial capacity shortfall that would be challenging to replace all at once. Additional contributions from the SEPA hydro resources and DSM programs further support resource adequacy.

Winter is Big Rivers' constrained season, with [redacted], and the IRP evaluates how the Company can [redacted]. Because development of new generation requires substantial lead time, the modeling framework assumes short-term capacity purchases to serve as a bridge to balance fluctuations in annual resource accreditation and factors in the transitions to MISO's DLOL framework. This approach allows market capacity purchases to satisfy limited seasonal needs without prematurely constructing an oversized resource. Beginning in 2031, the model may select new capacity resources when economically justified, including in scenarios that permit the replacement or retirement of Green and Wilson before the end of the study period.

Figure 6.7.4(b)

Big Rivers' Winter Capacity Position[102]



6.7.5 Current Annual Generation Position

Big Rivers' starting energy position reflects the balance between energy supplied from owned and contracted generation resources and energy procured from the wholesale market over the planning horizon. As shown in Figure 6.7.5(a), the analysis assumes continued operation of Green and Wilson through 2050, which together provide the majority of energy produced within the portfolio. These dispatchable thermal resources are complemented by contributions from SEPA hydro and the Unbridled Solar facility, as well as incremental DSM

[102] "Peak" in Figure 6.7.4(a) refers to Big Rivers CP and "Peak + Reserves" refers to Big Rivers MISO CP + the Planning Reserve Margin which makes this the Planning Reserve Margin Requirement used as the target for capacity planning.

programs. Collectively, these resources form the foundation of Big Rivers' energy supply and provide a combination of baseload, flexible, and renewable generation needed to meet system energy requirements.

A key planning objective reflected in this analysis is maintaining a high level of self-supplied energy to mitigate exposure to wholesale market price volatility. Big Rivers targets covering approximately [redacted] of total annual energy requirements through owned and contracted resources, using this threshold as a proxy for an appropriate market hedge. This approach limits reliance on capacity market purchases during periods of elevated or volatile prices while preserving operational flexibility by allowing Big Rivers to purchase energy from the market when doing so is less costly than operating its natural gas-fired resources. As a result, when the IRP model evaluates future resource additions, it considers not only capacity needs but also the ability of candidate resources to contribute sufficient energy to maintain this target level of self-supply. Therefore, resources selected within the optimization framework must support both resource adequacy and the energy coverage requirement, ensuring a balanced portfolio that manages cost risk while maintaining reliability.

Figure 6.7.5(a)

Big Rivers' Annual Generation Position



6.7.6 Green and Wilson Reliability Projects

As part of the IRP capacity expansion analysis, Big Rivers included reliability-focused investment options associated with Green and Wilson. Rather than assuming these projects would automatically be implemented, the investments were modeled as selectable resource alternatives within the capacity expansion framework. This approach allows the optimization model to evaluate the costs and benefits of investing in existing generation assets relative to retiring and replacing those resources with new capacity. As a result, the model can determine whether extending the life and improving the performance of an

existing unit is more economical than retirement under a given set of future conditions.

6.7.7 Green Fuel Oil Backup Project

The IRP evaluates an option to add fuel oil backup at Green Units 1 and 2 through the installation of approximately four million gallons of on-site fuel oil storage. The proposed project would provide up to 96 hours of backup fuel capability, allowing the units to operate when natural gas supply is constrained or unavailable, particularly during peak winter conditions. The project is estimated to cost approximately [redacted] and to require an 18-month implementation period, resulting in a projected in-service date of January 2029.[103]

Natural gas procurement constraints during periods of high demand have historically reduced the actual and future expected winter availability of Green and, consequently, their accredited capacity under MISO's SAC and DLOL frameworks. Adding fuel oil backup materially improves the units' expected availability and ability to operate during critical reliability hours. Winter accreditation increases from between approximately 35% and 36% to between approximately 66% and 67%, providing an estimated 143 MW of additional accredited capacity. Summer accreditation also improves modestly due to enhanced start-up capability and availability within MISO's accreditation

[103] *See In the Matter of: Electronic Application of Big Rivers Electric Corporation for Approval to Retire the Reid Combustion Turbine Pursuant to KRS 278.264, for a Certificate of Public Convenience and Necessity Related to Backup Fuel Capability at Green Station, and for Other Appropriate Relief*, Ky. P.S.C. Case No. 2026-00291.

methodology, as shown in Figure 6.7.7(a). In addition to improving resource adequacy under MISO's evolving accreditation framework, the project helps offset the retirement of the 65 MW Reid CT and reduces the need for near-term replacement capacity additions until longer-lead resource options become commercially available. Section 6.7.9, Reid CT Replacement Need, provides more detail regarding the Reid CT.

Within the IRP capacity expansion analysis, the fuel oil backup option is evaluated against alternative resource investments to determine whether the improved reliability contribution and increased accredited capacity, justify the project cost. The benefits are most significant during winter when natural gas system constraints are most likely to limit unit availability and create resource adequacy risk.

Figure 6.7.7(a)

Green Accreditation Improvements from Fuel Oil Backup

Capacity Improvement (MW)				
2029/2030	**Summer**	**Fall**	**Winter**	**Spring**
Green Accreditation Current	364.6	364.6	181.3	261.5
Green Accreditation with Fuel Oil Backup	375.5	370.4	325.0	288.5
Accreditation Improvement	10.9	5.8	143.6	26.9

6.7.8 Wilson Reliability Projects

The 2026 IRP also evaluates the cost-effectiveness of added reliability assurance for Wilson, a series of repairs and replacements designed to restore the unit's long-term reliability. When initial modeling confirmed that Wilson would

be needed through the planning horizon, Big Rivers evaluated the cost-effectiveness of these projects, including boiler and duct work repairs, coal yard improvements, replacement of piping, valves, pumps and motors, as well as electrical controls and drag chain replacement. The projects are spread across the 2027 through 2029 period, with a total estimated cost investment of [redacted] including contingency.

Within the capacity expansion model, Wilson is treated as a strategic decision point. The model may either retire the unit as early as December 31, 2032 (considering a timeline sufficient to satisfy Kentucky's law regarding the retirement and replacement of fossil fuel-fired generation and to allow for the development and construction of interconnected generation resources), and replace its capacity with alternative resources by January 1, 2033, or elect to make the [redacted] investment and preserve the unit as a long-term dispatchable generating resource. Under scenarios that include fixed retirement of Wilson in 2045, the cost of the projects remains part of the portfolio because the investments help ensure reliable operation through the assumed retirement date. This approach allows the IRP to evaluate the tradeoffs between continued operation of an existing dispatchable asset and replacement with new resources under varying market, regulatory, and reliability conditions.

6.7.9 Reid CT Replacement Need[104]

The Reid CT, a natural gas-fired combustion turbine unit, experienced a forced outage in August 2024 due to catastrophic mechanical issues and is therefore assumed to provide no capacity or energy contribution over the 2026 IRP planning period. Because the Reid CT is a dispatchable fossil-fueled generating resource, its retirement must be evaluated in the context of KRS 278.264, which establishes a rebuttable presumption against retirement of such resources. As a result, retirement generally would require a demonstration that the units is no longer necessary to provide adequate and reliable electric service or that adequate replacement dispatchable is available to maintain reliable service. Accordingly, a key objective of this IRP is to evaluate to what extent replacement of the Reid CT remains necessary.

The IRP evaluated whether a new dispatchable resource would be required to replace the Reid CT. Given current market conditions, however, the development of new dispatchable generation requires substantial lead time due to increasing demand for natural gas-fired resources, equipment procurement constraints, engineering requirements, permitting activities, and construction and interconnection schedules. As a result, the earliest practical in-service date for a replacement resource is assumed to be 2031. Therefore, the relevant planning question is not whether capacity is needed immediately following the loss of the

[104] Responsive to 807 KAR 5:058, Section 8(4).

Reid CT, but whether Big Rivers continues to have a capacity need when a replacement resource could realistically be developed and placed into service.

The analysis indicates that short-term capacity purchases provide the most economical and flexible means of addressing the temporary resource adequacy need created by the loss of the Reid CT. Limited market capacity purchases are utilized during the near-term period to bridge any seasonal capacity needs while longer-term reliability investments are implemented. This approach preserves resource adequacy without requiring a substantial capital investment [redacted]

By 2031, the time a new replacement resource could reasonably be permitted, constructed, and placed into service, the need for replacement capacity has been eliminated through other actions selected by the 2026 IRP. The Green Fuel Oil Backup Project increases winter accredited capacity by approximately 144 MW, while the DSM portfolio contributes approximately 17 MW of winter peak demand reduction. In addition, continued operation of Wilson and implementation of the reliability projects preserve significant accredited dispatchable capacity throughout the planning horizon.

As a result, the Reference Case portfolio provides sufficient accredited and dispatchable capacity to satisfy reliability requirements without construction of a new-build replacement resource for the Reid CT. In fact, by the time a replacement resource could realistically enter service, the portfolio is projected to provide sufficient excess capacity to exceed Big Rivers' forecasted peak load

requirements. Constructing a new build replacement for the Reid CT would therefore require a substantial long-term capital [redacted] Consequently, the 2026 IRP supports Big Rivers' plan to retire the Reid CT pursuant to KRS 278.264, through demonstrating that construct the Green Fuel Oil Backup Project maintains reliable service.

6.8 Model Inputs[105]

6.8.1 Discount Rate and Inflation Assumptions[106]

Consistent with industry practice, all costs evaluated in the IRP were discounted to present value using Big Rivers' Weighted Average Cost of Capital ("WACC"). The WACC represents the Company's cost of financing and serves as the appropriate discount rate because it reflects the opportunity cost of capital associated with long-term resource investments. Using the WACC ensures resource alternatives with different cost structures and timing of expenditures can be compared on a consistent economic basis. For this IRP, Big Rivers utilized a nominal WACC of 4.75%.

As a generation and transmission cooperative, Big Rivers finances its operations primarily through debt rather than shareholder equity. Accordingly,

[105] Responsive to 807 KAR 5:058, Section 8(5)(a)-(f).

[106] Responsive to 807 KAR 5:058, Section 9(2).

the WACC calculation assumes a capital structure consisting of 100% debt and 0% equity, reflecting the cooperative business model and the absence of investor-owned shareholder capital. This approach is consistent with how Big Rivers evaluates investment decisions and measures the cost of capital incurred on behalf of its member-owners.

All future costs and revenues were modeled in nominal dollars and incorporate an assumed long-term inflation rate of 2.57% per year. The inflation assumption reflects general long-term expectations for price escalation across labor, materials, O&M expenses, and other utility cost categories. Applying a consistent inflation assumption throughout the analysis ensures that future resource costs, fuel expenses, market prices, and capital investments are evaluated on a comparable basis. Together, the 4.75% WACC and 2.57% inflation rate provide the financial framework used to assess the relative economics of alternative resource portfolios throughout the IRP.

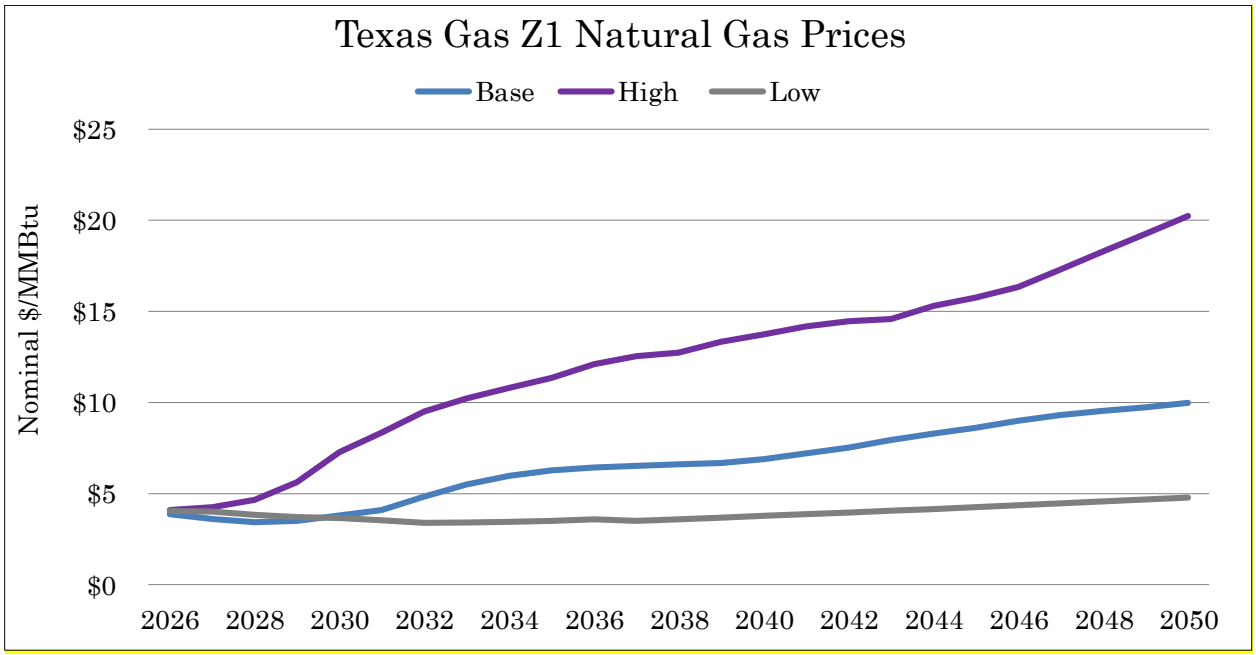
6.8.2 Natural Gas Prices

Long-term natural gas price forecasts for the IRP are based on the U.S. Energy Information Administration's ("EIA") Annual Energy Outlook ("AEO") 2025 reference, high, and low natural gas price cases. Because Big Rivers procures natural gas primarily through the Texas Gas Zone 1 pipeline, a basis adjustment was applied to the AEO 2025 Henry Hub forecasts to develop the corresponding Texas Gas Zone 1 price forecasts used in the analysis. As shown in Figure 6.8.2(a), the Base Case forecast increases gradually from approximately

$4/MMBtu in 2026 to approximately $10/MMBtu by 2050, while the Low and High forecasts diverge significantly over time, reaching approximately $5/MMBtu and $20/MMBtu, respectively, by the end of the planning horizon. These natural gas price forecasts were then used as key inputs to ACES' fundamental power market model to develop the wholesale power price forecasts used throughout the IRP. This approach ensures the natural gas and power price assumptions remain internally consistent within each scenario and appropriately reflect the strong relationship between fuel costs and wholesale electricity market prices.

Figure 6.8.2(a)

Texas Gas Zone 1 Natural Gas Prices



6.8.3 Coal Prices

Coal fuel price assumptions used in the IRP are shown in Figure 6.8.3(a). Unlike natural gas and wholesale power prices, which were varied across

scenarios to reflect different market futures, a single coal price forecast was applied consistently across all scenarios. This approach reflects the relatively stable and predictable nature of coal markets compared to other fuel commodities and recognizes that future coal costs are expected to be driven primarily by contracted supply arrangements, transportation costs, and general inflationary pressures rather than the level of volatility observed in natural gas markets.

The coal price forecast was based on Big Rivers' near-term contracts and then blended into ACES' forward curve for Illinois Basin coal. As shown in Figure 6.8.3(a), delivered coal costs increase gradually throughout the planning horizon, from approximately [redacted] in 2025 to approximately [redacted] by 2050. The forecast consists of a commodity component and a delivery component, with transportation costs remaining relatively stable over time, while commodity costs account for most of the increase in total delivered fuel costs. The resulting forecast provides a reasonable representation of long-term coal costs while maintaining consistency across all planning scenarios.

Figure 6.8.3(a)

Coal Prices



6.8.4 Power Prices

Long-term wholesale power price forecasts for the IRP were developed by ACES using a fundamental market model that incorporates assumptions regarding future load growth, fuel prices, generation additions and retirements, transmission constraints, and other market fundamentals.[107] As shown in Figure 6.8.4(a), the Base Case forecast increases steadily from approximately $42/MWh in 2026 to approximately $87/MWh by 2050, while the Low Case remains

[107] ACES' Fundamentals Forecasts are long-term energy market forecasts developed by ACES using fundamental supply-and-demand modeling of the North American energy markets. The forecasts incorporate assumptions regarding fuel supply and demand, generation retirements and additions, transmission constraints, environmental regulations, and market fundamentals to project future wholesale power prices used in resource planning analyses.

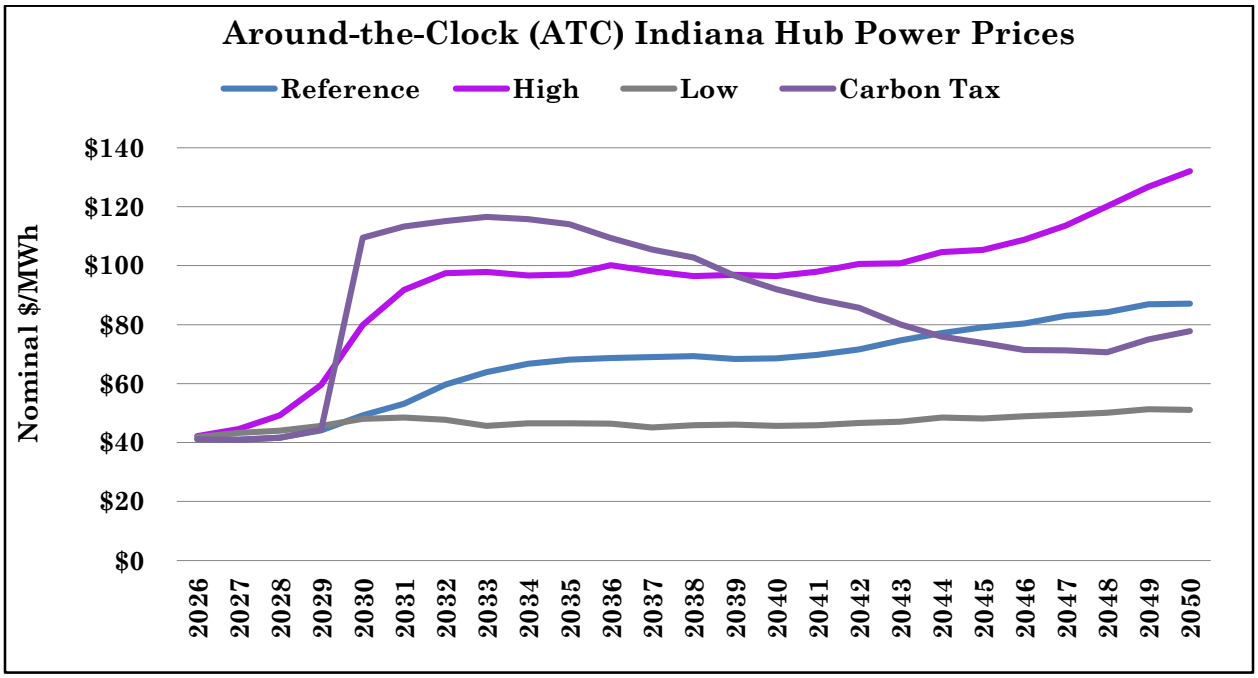
relatively flat, increasing only modestly to approximately $51/MWh over the planning horizon. The High Case follows a significantly steeper trajectory, increasing to approximately $132/MWh by 2050 as a result of higher natural gas prices and the corresponding increase in generation costs across the market.

In addition to the Reference, High, and Low forecasts, ACES developed a custom Carbon Tax power price forecast for use in the High Regulatory scenario.[108] As shown in Figure 6.8.4(a), the Carbon Tax forecast diverges sharply beginning in 2030 when the assumed carbon pricing policy is introduced. Power prices increase rapidly to between $115/MWh and $117/MWh in the early 2030s as carbon-emitting generation incurs additional operating costs and the market adjusts to the new regulatory environment. However, over time, the forecast gradually declines and converges toward the Reference Case as generation investment shifts toward lower-emission or renewable resources and the market adapts to the carbon-constrained environment. By 2050, the Carbon Tax forecast is approximately $78/MWh, which remains below the Base Case forecast for much of the later planning period. These forecasts provide the basis for evaluating the impact of alternative market and regulatory futures on portfolio economics and resource selection throughout the IRP.

[108] High EIA AEO natural gas prices were used in the custom Carbon Tax power price forecast.

Figure 6.8.4(a)

Around-the-Clock Indiana Hub Power Prices



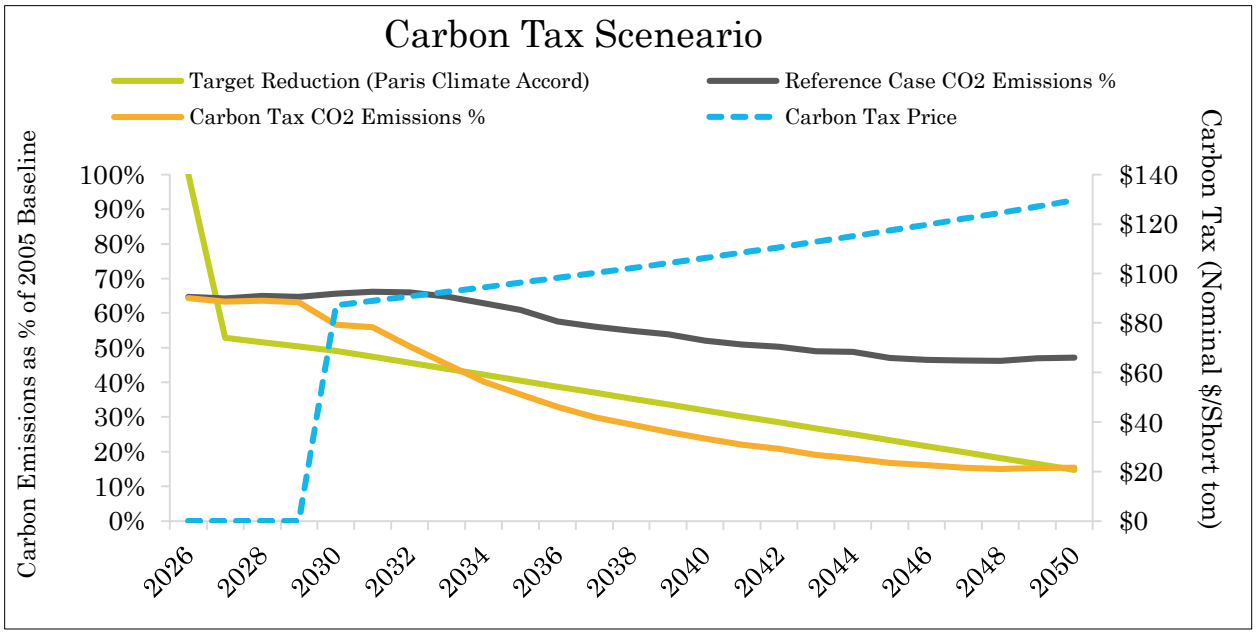
6.8.5 Carbon Tax

The custom Carbon Tax power price forecast was developed to evaluate a future in which increasingly stringent carbon regulations drive significant reductions in U.S. power sector emissions. As shown in Figure 6.8.5(a), the scenario assumes a national carbon price beginning at approximately $85/short ton in 2030 and increasing steadily to approximately $130/short ton by 2050. The resulting market response drives substantial emissions reductions in the U.S. relative to the Reference Case, with carbon emissions declining from approximately 64% of 2005 levels in 2030 to approximately 15% of 2005 levels by 2050. Notably, the emissions trajectory achieved under the Carbon Tax Scenario closely tracks – and in later years slightly exceeds – the reduction pathway

associated with the Paris Climate Accord targets, indicating that the assumed carbon pricing framework is sufficient to drive deep decarbonization of the electric sector. By comparison, the Reference Case power price forecast results in more gradual emissions reductions, remaining near 47% of 2005 levels by 2050. The carbon pricing assumptions shown in Figure 6.8.5(a) were also included in the IRP's High Regulatory scenario for resource selection and economics, ensuring that the market assumptions used in the IRP reflect a consistent carbon-constrained future as those used in the Fundamental power price model.

Figure 6.8.5(a)

Carbon Tax Power Price Scenario Overview



6.8.6 New Resource Options[109]

Supply-side resource costs, performance characteristics, and operating assumptions were developed using data provided by ACES[110] and informed by publicly available sources, including the National Renewable Energy Laboratory's ("NREL") 2024 Annual Technology Baseline and the EIA. Resource technologies were selected for inclusion in the IRP based on their ability to support long-term resource adequacy, commercial availability, regulatory considerations, and operational compatibility with Big Rivers' existing fleet. To reflect the

[109] Responsive to 807 KAR 5:058, Section 8(5)(c).

[110] Near-term cost data for resources was extracted from recent Requests for Proposals facilitated by ACES' Origination team for resources and used as benchmarks for the resource pricing. Data was blended with secondary sources to create a forecast over the planning period.

development and construction timelines associated with new generation resources, all candidate resource technologies were assumed to be available for selection beginning in 2031.

To provide flexibility in the capacity expansion analysis, candidate resources were modeled using standardized resource blocks rather than full project sizes. Natural gas generation, solar, wind, and battery storage technologies were modeled in 50 MW increments, allowing the model to identify the quantity and timing of resource additions needed to satisfy system requirements without being constrained by a specific project size. While individual 50 MW additions may not represent a stand-alone development opportunity, the approach provides a reasonable approximation of future resource needs and reflects the potential for partial ownership arrangements, joint ownership structures, tolling agreements, and other contractual solutions. Accordingly, the selected resource quantities should be viewed primarily as indicators of the resource types and approximate capacity levels that are economically preferred under the modeled assumptions rather than definitive project development recommendations.

While for preparation of this IRP Big Rivers did not coordinate with any other utility related to the construction or operation of a new generating unit, the Company continues to evaluate opportunities for regional coordination and participation in industry initiatives that may provide cost-effective resource options for its Members. As a member of Kentucky Electric Cooperative, Inc.

("KEC"), Big Rivers regularly engages with other Kentucky cooperatives regarding issues affecting long-term resource planning, generation technologies, transmission development, reliability, and emerging industry trends. Big Rivers also monitors industry developments and regulatory proceedings that may affect future opportunities for coordinated resource development, including discussions regarding advanced nuclear generation technologies, regional transmission initiatives, and other potential collaborative approaches to meeting future capacity and energy needs. Although no jointly developed generation project is currently under consideration, Big Rivers remains open to evaluating joint ownership arrangements, shared development opportunities and other cooperative solutions that may provide economic or operational benefits to its Members. [111]

Big Rivers has also demonstrated its willingness to pursue cooperative utility solutions when beneficial. For example, Big Rivers coordinated with Kentucky Utilities Company, Louisville Gas and Electric Company, and Owensboro Municipal Utilities in connection with transmission arrangements supporting OMU's transition to the MISO transmission system. While this effort did not involve the construction of generating facilities, it illustrates Big Rivers' ability to work collaboratively with other utilities to implement regional infrastructure solutions and evaluate opportunities that may provide long-term customer benefits.

[111] Responsive to 807 KAR 5:058, Section 8(2)(c).

6.8.6.1 Natural Gas Resources

Four natural gas-fired technologies were evaluated as candidate resources in the IRP beginning in 2031: F-frame CTs, F-frame combined-cycle (CC) units, aeroderivative natural gas turbines ("AERO"), and reciprocating internal combustion engines. These technologies provide dispatchable generation capable of supporting both resource adequacy and energy needs under a wide range of operating conditions.

The candidate technologies exhibit different cost and operational characteristics, as summarized in Figure 6.8.6.1(a). CC generation provides the lowest heat rate and variable operating cost among the natural gas technologies considered, making it well suited for sustained operation and energy production. In contrast, CTs, AEROs, and RICE technologies generally have higher operating costs but offer greater operating flexibility, faster start capabilities, and the ability to respond quickly to changing system conditions. As a result, these technologies are typically utilized to meet peak demand requirements, provide reliability support, and supplement variable renewable generation.

Capital cost forecasts for the candidate thermal technologies are shown in Figure 6.8.6.1(b), while the operating characteristics used in the IRP are summarized in Figure 6.8.6.1(a). Fixed and variable O&M costs were escalated throughout the planning horizon using inflation assumptions consistent with the broader IRP modeling framework. These assumptions allow the capacity expansion model to evaluate competing resource options on a consistent basis and

identify the technologies that provide the most cost-effective combination of capacity, energy, and operational flexibility under each planning scenario.

Figure 6.8.6.1(a)

New Natural Gas Resource Operating Characteristics

General Assumptions for Natural Gas Turbines for 2031 COD				
	F-Frame CT	F-Frame CC	AERO	RICE
Heat Rate at Maximum (Btu/kWh)	9,960	6,400	9,300	8,450
CAPEX ($/kW)	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW-Year)	$30.99	$39.24	$21.81	$47.04
Variable O&M ($/MWh)	$8.67	$2.52	$6.29	$7.61
Release Rate – CO_2 (lb./MMBtu)	119	119	119	119

Figure 6.8.6.1(b)

New Natural Gas Resource Capital Costs



6.8.6.2 Energy Storage Resources

Utility-scale energy storage resources were evaluated as potential portfolio options within the IRP, including 4-hour standalone battery storage, 4-hour battery storage paired with solar generation, and 100-hour long-duration energy storage. The 4-hour storage technologies are assumed to utilize lithium-ion batteries and provide operational flexibility through energy shifting, peak reduction, and reliability support. The 100-hour storage resource is based on iron-air battery technology, representing a commercially emerging long-duration storage solution capable of providing sustained energy delivery during extended reliability events. To reflect realistic operating performance, storage resources were modeled using technology-specific assumptions for round-trip efficiency, annual utilization limits, and expected commercial availability.

The cost assumptions used for the candidate storage technologies are summarized in Figure 6.8.6.2(a), while capital cost forecasts are shown in Figure 6.8.6.2(b).[112] Four-hour battery storage becomes available for selection beginning in 2031, with 100-hour storage available beginning in 2035.[113] As illustrated in Figure 6.8.6.2(b), short-duration storage has a significantly lower capital cost than long-duration storage throughout the planning horizon, although both technologies are affected by the assumed phaseout of federal tax incentives

[112] Hybrid pricing shown is for battery portion of the hybrid system only. The solar portion is presented in the solar cost section.

[113] Delay used for 100-hour storage to account for lag until this technology becomes commercially available.

beginning in 2033 and ending in 2035. Within the IRP, energy storage competes alongside thermal and renewable resources as a means of improving operational flexibility, supporting renewable integration, and contributing to system reliability, with its overall value dependent on economics and accredited capacity contributions under MISO's resource adequacy framework.

Figure 6.8.6.2(a)

New Battery Energy Storage Operating Characteristics

Cost Assumptions for Battery Storage		
	4-Hour Storage (2031 COD)	100-Hour Storage (2035 COD)
CAPEX ($/kW)	[redacted]	[redacted]
Fixed O&M ($/kW-Year)	$39.99	$34.06

Figure 6.8.6.2(b)

New Battery Energy Storage Capital Costs



6.8.6.3 Solar Resources

Solar resources were evaluated as a potential supply-side option within the IRP using a generic utility-scale, single-axis tracking solar facility with an assumed average annual capacity factor of approximately 23%. Solar generation was modeled as a standalone resource and in combination with 4-hour battery storage, allowing the capacity expansion model to evaluate the relative economics and operational benefits of solar-only and solar-plus-storage configurations.

The cost assumptions used in the IRP are shown in Figure 6.8.6.3(a), which presents the projected levelized cost of energy (LCOE) for standalone and hybrid solar resources through 2050.[114] Solar project costs can vary significantly based on factors such as interconnection requirements, project size, construction timing, and site-specific conditions. As illustrated in Figure 6.8.6.3(a), both solar resource options experience declining costs through the mid-2030s before stabilizing and gradually increasing over the remainder of the planning horizon . Throughout the study period, solar paired with storage maintains a slight economic advantage relative to standalone solar, reflecting the additional operational flexibility and the cost savings of combining interconnection at a single site.

[114] Hybrid pricing shown is for the solar portion of the hybrid system only. The battery portion is presented in the battery cost section.

Figure 6.8.6.3(a)

New Solar Capital Costs



6.8.6.4 Wind Resources

Wind generation was evaluated as a potential renewable resource option within the IRP. Because Kentucky has limited wind resource potential and no utility-scale wind development, candidate wind resources were assumed to be located in Indiana, which offers more favorable wind characteristics in MISO capacity zone 6, the same zone as Big Rivers. The generic wind resource was modeled using an average annual capacity factor of approximately 34.5%, representing the expected performance of a utility-scale wind facility in the region. An out-of-state resource introduces additional development and delivery

considerations, and transmission congestion impacts were incorporated directly into the resource cost assumptions used in the analysis.

The projected cost assumptions for wind generation are shown in Figure 6.8.6.4(a), which presents the LCOE through 2050. As illustrated in the figure, wind costs decline modestly through the mid-2030s before stabilizing and gradually increasing over the remainder of the planning horizon. These cost trends reflect changes in capital investment requirements, operating costs, and broader market assumptions incorporated into the IRP. Wind resources compete directly with other generation technologies in the capacity expansion analysis and are evaluated based on their ability to provide economic energy and capacity, reduce market purchases, and contribute to portfolio diversification while satisfying applicable reliability and resource adequacy requirements.

Figure 6.8.6.4(a)

New Wind Capital Costs



6.8.6.5 Emerging Technologies

Big Rivers evaluated several emerging generation technologies, including small modular reactors ("SMR"), advanced and alternative storage technologies, carbon capture technologies for coal and natural gas generation, and advanced geothermal resources, as part of the IRP screening process. While these technologies show potential to support future reliability and decarbonization objectives, aside from 100-hour storage, they were not included as selectable resources in the capacity expansion analysis. These technologies currently have limited commercial deployment, uncertain development timelines, and insufficient operating and cost experience to support near- or medium-term resource planning decisions. In addition, first-of-a-kind engineering, permitting, supply chain,

infrastructure, and construction risks create significant uncertainty regarding project cost, performance, and implementation schedules.

Publicly available cost estimates also suggest that emerging technologies remain less economical than the commercially established generation technologies evaluated in this IRP. As a result, these resources were not expected to be competitive under the market, fuel price, and regulatory assumptions considered in the analysis. While they were excluded from the candidate resource set for this IRP, Big Rivers will continue to monitor technological advancements, commercialization efforts, vendor offerings, and cost trends associated with emerging technologies. As these technologies mature and their performance, costs, and development timelines become more certain, they may warrant consideration as potential resource options in future planning cycles.

Specifically, Big Rivers continues to monitor and participate in the Public Service Commission administrative case on nuclear energy and is active on the Kentucky Nuclear Energy Development Authority, with Chief Executive Officer ("CEO") Don Gulley being a member appointed by the Governor. There are many benefits to having nuclear energy in the generation portfolio. Large energy intensive industries will be additional baseload generation options available by mid 2030s into 2040. Nuclear offers the ability to mitigate natural gas price volatility as well as optionality in gas constrained areas that need baseload power. Renewable generation is facing increasing opposition at the local level due to the low energy density of the generation and the acreage required. Nuclear provides

an energy dense option with lower land impacts as well as zero carbon resource. Adding nuclear to the portfolio may also drive system cost reductions as well as providing an 80-year asset.

Big Rivers recognizes that a large nuclear energy project such as Georgia Power's Voglte units would be untenable to our members, even though the technology is more proven at this time. The cost and scope of such a project would be impossible under existing circumstances. Hopefully by the time we are evaluating IRPs in the near term there will exist more certainty about the commercial viability and cost of small nuclear reactors ("SMR"). In that vein, Big Rivers will follow closely and consider the incentives in Senate Bill 56 as passed in the 2026 Session of the Kentucky General Assembly. These incentives would help off-set costs associated with developing a site plan for long-term investments in nuclear energy.

It is likely that any nuclear development as a part of Big Rivers portfolio would be an alternative model to utility development and sole ownership. Similarly to the member rate protections around large data centers, there would likely be an attempt to ring-fence the development to eliminate risk to member-consumers and member-owners. Therefore, not modeling this resource currently is a no regrets modeling exercise. There are no new generation resources planned and nuclear as well as other emerging technologies can be modeled in a subsequent IRP when there is less uncertainty.

6.8.7 New Resource Accreditation

Capacity accreditation assumptions for the new resource options were based on MISO's DLOL accreditation framework beginning in PY 2028/2029. The primary source for future accreditation values was MISO's 2024 Regional Resource Assessment. The resulting accreditation assumptions were applied throughout the IRP to evaluate the relative reliability contribution of alternative resource technologies and to determine each portfolio's ability to satisfy future resource adequacy requirements.

As shown in Figure 6.8.7(a) and Figure 6.8.7(b), dispatchable thermal technologies maintain relatively stable accreditation values throughout the planning horizon, with natural gas CC resources generally receiving accreditation values near 90% of installed capacity and combustion turbine technologies receiving accreditation values ranging from approximately 65% to 80%, depending on fuel configuration and season. Dual-fuel CTs receive higher accreditation values than single-fuel CTs due to their enhanced fuel flexibility and expected availability during system stress events.

Renewable and energy storage resources exhibit more variable accreditation trends. Solar accreditation is relatively modest during summer peak periods and declines to little or no accredited capacity during winter months because generation availability does not align with MISO's expected reliability risk hours. Wind accreditation remains relatively low in both seasons, generally ranging from approximately 10% to 20% of installed capacity. Battery storage

resources receive relatively high accreditation values initially; however, accredited capacity declines over time, particularly for shorter-duration storage technologies. As illustrated in Figure 6.8.7(a), winter accreditation for 4-hour storage decreases significantly over the study period, reflecting the increasing importance of sustained energy availability during extended winter reliability events under the DLOL framework. Longer-duration storage technologies maintain higher accreditation values but also experience gradual declines over time.

The accreditation trends shown in Figure 6.8.7(a) and Figure 6.8.7(b) highlight the differing reliability characteristics of available resource technologies. While renewable and storage resources provide important energy, diversity, and operational benefits, the analysis demonstrates that dispatchable thermal resources continue to provide the largest accredited capacity contribution toward meeting MISO planning reserve requirements.

Figure 6.8.7(a)
MISO Winter Capacity Accreditation for New Resource Options

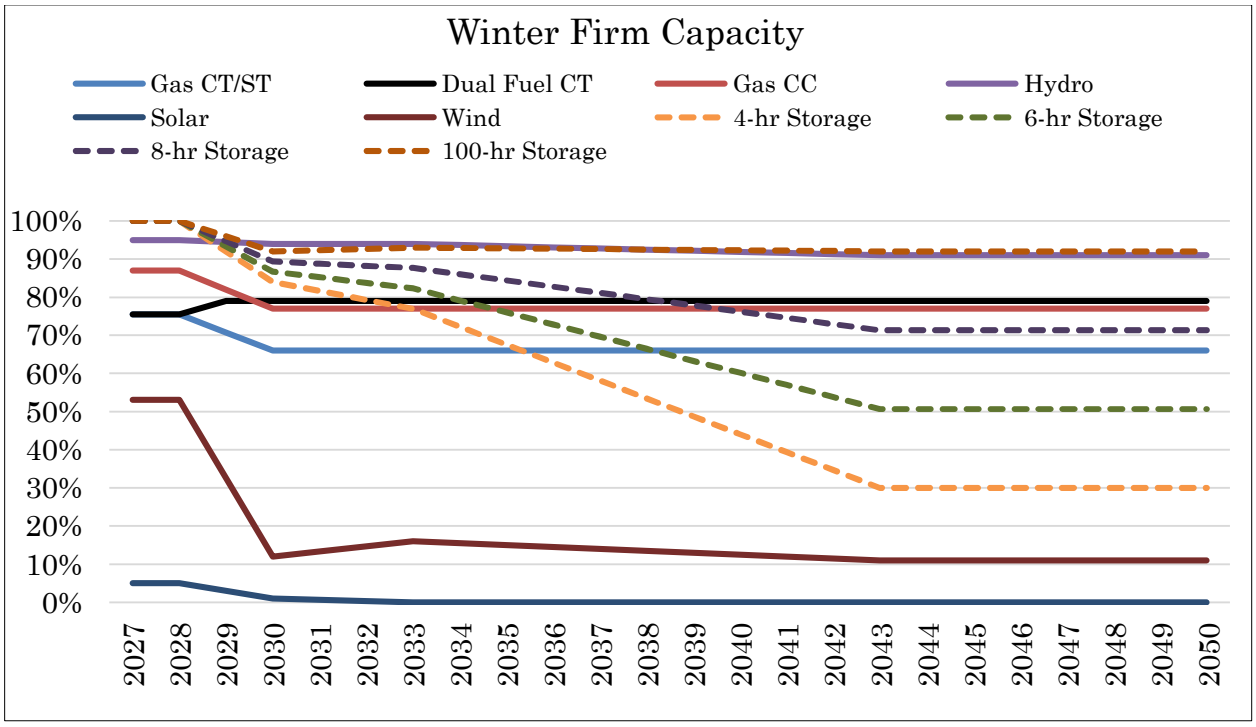
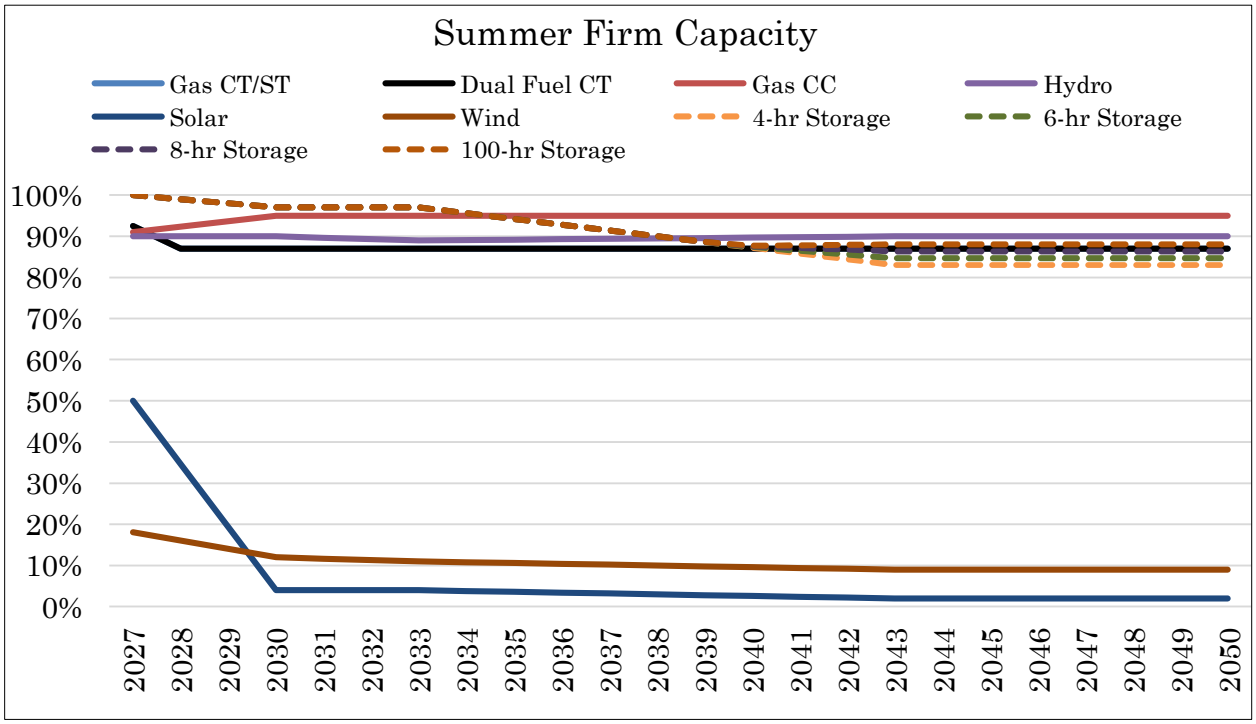


Figure 6.8.7(b)
MISO Summer Capacity Accreditation for New Resource Options



6.8.8 Renewable Resource Development Limits

To reflect practical development considerations, the IRP limits cumulative new solar and wind additions to a combined total of 800 MW over the planning horizon. While the model evaluates renewable resources based on their economics and ability to satisfy system requirements, unconstrained optimization can sometimes select quantities of renewable generation that may exceed what could reasonably be developed, contracted, interconnected, and integrated within the study timeframe. The 800 MW limit was therefore applied as a planning assumption to reflect potential constraints associated with project siting, land availability, transmission and interconnection requirements, permitting considerations, supply chain limitations, and the availability of commercially viable renewable development opportunities within the region.

The limit is not intended to represent a physical system constraint or a policy position regarding renewable generation. Rather, it serves as a reasonable planning assumption that prevents the model from selecting unrealistically large quantities of renewable resources while still allowing sufficient flexibility to evaluate the economic role of solar and wind generation within future resource portfolios. As a result, the renewable additions selected by the model are more representative of resource development opportunities that could reasonably be expected to materialize over the planning horizon.

6.9 Capacity Expansion Results[115]

The following section presents the capacity expansion results developed through the IRP Scenario Analysis. Ten resource portfolios were evaluated, reflecting combinations of five future scenarios (four discrete futures and one additional future that ensures compliance with Kentucky law, specifically KRS 278.264, in the High Regulatory/Carbon Tax future) and two retirement approaches for Green and Wilson (Section 6.5.2, IRP Scenario Analysis and Portfolio Development, includes additional details regarding the Scenario Analysis framework). For each portfolio, the capacity expansion model identified the resource additions, retirements, and market interactions required to most optimally and cost effectively satisfy forecast load and resource adequacy requirements under the specified planning scenario assumptions. Reviewing the resulting portfolios provides insight into how resource needs and investment decisions may vary across alternative future conditions and retirement strategies, as well as the common themes that emerge across multiple planning futures.

For purposes of reviewing the capacity expansion results, the winter capacity position is used as the primary measure of resource adequacy because winter is Big Rivers' most constrained season. Summer capacity is less restrictive, and the portfolio has excess capacity due to stronger seasonal resource accreditation. Additionally, any resource additions or portfolio changes needed to

[115] Responsive to 807 KAR 5:058 Sections 8(1) and 8(4).

improve the winter position will naturally provide sufficient capacity to cover summer, spring, and fall, as well. Accordingly, the winter results provide the most informative measure of whether each portfolio can meet the load forecast and planning reserve requirements. Summer, fall, and spring results are reviewed to confirm all portfolio results satisfy Big Rivers' long-term reliability needs and no separate seasonal deficiency emerges. Summer capacity position charts for all scenarios can be found in Appendix D, Technical Appendix.

6.9.1 Reference Case – Optimization Results

6.9.1.1 Reference Case – Optimization Results: Winter Capacity Position

Figure 6.9.1.1(a) provides the resulting winter capacity position for the Reference Case with Optimized Retirements portfolio. Under the Reference Case assumptions, the optimized portfolio chooses to continue the operation of Green and Wilson throughout the planning horizon and selects investments that enhance the long-term reliability and capacity value of Green and maintaining the reliability of Wilson. Specifically, the model elects to implement the Green Fuel Oil Backup Project, increasing the accredited capacity contribution of the Green units, particularly during winter periods when natural gas deliverability may be constrained. The model also selects the Wilson reliability projects, preserving reliable operation beyond 2032. With these investments in place, the existing dispatchable fleet provides sufficient accredited winter capacity through the end of the study period. In the Reference Case, the portfolio exceeds MISO's forecasted

planning reserve requirement in all seasons, which provides a buffer to changes in resource accreditation and load forecasts. The Optimized Retirements portfolio also includes approximately 600 MW of new solar ICAP beginning in 2037 and 50 MW of wind beginning in 2045. These renewable additions provide minimal accredited capacity but provide value as an energy hedge against expected higher natural gas and power prices.

The results shown in Figure 6.9.1.1(a) are also significant from a regulatory perspective because they demonstrate that a new build and/or one-for-one replacement of the Reid CT is not required to maintain resource adequacy. Although Big Rivers experiences a capacity need prior to implementation of the Green Fuel Oil Backup Project, a new dispatchable replacement resource could not reasonably be developed and placed into service before 2031. By 2031, the impact of the Green Fuel Oil Backup Project eliminates the projected capacity shortfall and maintains compliance with resource adequacy requirements. Consequently, the Reference Case portfolio demonstrates that equivalent replacement accredited capacity for the Reid CT is not necessary to provide reliable service.

Figure 6.9.1.1(a) [116]

Reference Case – Optimization: Winter Capacity Position [117]



6.9.1.2 Reference Case – Optimization Results: Annual Energy Position

Figure 6.9.1.2(a) presents the annual energy position for the Reference Case with Optimized Retirements portfolio. The portfolio relies primarily on existing dispatchable generation throughout the planning horizon, with Wilson supplying approximately one-half or more of annual energy requirements. Green provides a

[116] "DB Wilson.MISO Extension," as referenced in this section's figures, is the designation used in EnCompass when the Wilson reliability projects are selected as economic projects.

[117] "Peak" in Figure 6.7.4(a) refers to Big Rivers CP and "Coincident Peak + Reserves" refers to Big Rivers MISO CP + the Planning Reserve Margin which makes this the Planning Reserve Margin Requirement used as the target for capacity planning.

significant share of energy production in the early years; however, its output declines in the late 2030s as higher natural gas prices reduce the competitiveness of natural gas-fired generation. During this period, the model adds solar generation and a modest amount of wind generation, which serves the portfolio's incremental energy needs. As a result, renewable resources contribute an increasing share of energy production over time, while the existing thermal fleet continues to provide the majority of the portfolio's dispatchable capacity, reliability, and operational flexibility.

Figure 6.9.1.2(a)

Reference Case – Optimization: Energy Position



6.9.2 Reference Case – Fixed Retirements Results

6.9.2.1 Reference Case – Fixed Retirements Results: Winter Capacity Position

Figure 6.9.2.1(a) provides the resulting winter capacity position for the Reference Case with Fixed Retirements[118] portfolio. In this portfolio, the model maintains Green and Wilson through their prescribed retirement dates, 2039 and 2045, respectively, and selects both the Green Fuel Oil Backup Project and Wilson's implementation of the reliability projects during the transition period. The model selects 250 MW of F-frame CT capacity when Green retires to satisfy portfolio capacity needs and comply with KRS 278.264 requirements that retired thermal resources be replaced with dispatchable generation. Following Wilson's retirement, the model adds an additional 100 MW of CT capacity and 300 MW of CC capacity. These dispatchable additions replace the required accredited capacity previously provided by Green and Wilson while maintaining adequate reserve margins throughout the planning horizon. Like the optimized Reference Case portfolio, the model also selects solar and wind additions later in the study period; however, these resources are chosen primary for their energy value.

[118] The Fixed Retirements strategy assesses retirement and replacement of Green on December 31, 2039, and Wilson on December 31, 2045, across scenarios.

Figure 6.9.2.1(a)

Reference Case – Fixed Retirements: Winter Capacity Position[119]



6.9.2.2 Reference Case – Fixed Retirements Results: Annual Energy Position

Figure 6.9.2.2(a) presents the annual energy position for the Reference Case with Fixed Retirements portfolio. Prior to the fixed retirement of Green in 2039 and Wilson in 2045, most energy requirements are supplied by the existing generation fleet. Consistent with the Optimized Reference Case portfolio, the model adds solar generation in the late 2030s and wind generation later in the

[119] "Peak" in Figure 6.7.4(a) refers to Big Rivers CP and "Coincident Peak + Reserves" refers to Big Rivers MISO CP + the Planning Reserve Margin which makes this the Planning Reserve Margin Requirement used as the target for capacity planning.

planning horizon because these resources provide lower-cost energy than market purchases or owned natural gas generation. Following the retirement of Green and Wilson, a significant portion of energy production shifts to the newly added CC resource, while CTs serve primarily a reliability and capacity role. By the end of the planning period, the portfolio's energy needs are met through a combination of CC generation, renewable resources, existing contracted resources, and market transactions, resulting in a diversified energy supply portfolio that replaces the energy contribution of the retired thermal units.

Figure 6.9.2.2(a)

Reference Case – Fixed Retirements: Energy Position



6.9.3 Capacity Expansion Results of the Natural Gas Infrastructure Challenge, Low Load and Natural Gas Prices, and High Regulatory Scenarios

The Reference Case reflects Big Rivers' current most likely planning outlook for load growth, market conditions, regulatory requirements, and technology costs and, therefore, serves as the primary basis for evaluating future resource needs. The remaining scenarios test how the resource strategy could change if key conditions depart from the Reference Case outlook. In particular, the Low Load and Natural Gas Price scenario and the High Regulatory scenario represent less likely, but still relevant to planning, futures in which load growth materially underperforms expectations or more stringent environmental compliance requirements reemerge. The Natural Gas Infrastructure Challenge scenario similarly tests the impact of constraints on natural gas-fired development with high national load growth. To maintain focus in the IRP, the following sections emphasize model-selected resource additions and material differences from, and comparisons to, the Reference Case. Detailed capacity and energy-position results are provided in Workbook D-3 of Appendix D.

6.9.3.1 Model Optimization – Scenario Result Analysis

The Model Optimization portfolios demonstrate that, under the futures considered most likely to occur, the preferred strategy is to maintain Green and Wilson in operation through the planning horizon while investing in targeted reliability projects. As shown in Figure 6.9.3.1(a), the Reference Case and Natural Gas Infrastructure Challenges portfolios select the Green fuel oil backup project

and the Wilson reliability projects, allowing the existing dispatchable fleet to continue providing the majority of the system's capacity and reliability needs through 2050. More broadly, the analysis shows that Green remains in operation in every scenario evaluated and the Green Fuel Oil Backup Project is also selected, underscoring the consistent value of Green as a long-term reliability resource. While the Reference Case and Natural Gas Infrastructure Challenges portfolios add renewable resources over time, these additions are driven primarily by their economic energy value rather than a need for additional capacity. By 2050, the Reference Case portfolio includes approximately 600 MW of solar and 50 MW of wind, while the Natural Gas Infrastructure Challenges portfolio includes approximately 450 MW of solar and 350 MW of wind.

The two bookend scenarios (Low Load and High Regulatory) produce different outcomes for Wilson, as illustrated in Figure 6.9.3.1(a). Under the Low Load and Natural Gas Price scenario, Wilson is retired in 2039. The lower-growth environment reduces the need for new resources, resulting in additions of approximately 150 MW of CC generation and 250 MW of solar by the end of the planning period. In contrast, the High Regulatory (Carbon Tax) scenario retires Wilson at the earliest opportunity in 2032, and the Wilson reliability investment is not selected. In this scenario the portfolio shifts toward approximately 800 MW of wind generation, 400 MW of CC, and 200 MW of storage to satisfy future energy and capacity needs.

Because the unconstrained High Regulatory portfolio allows retiring dispatchable resources to be replaced in part by renewable generation, a separate High Regulatory – Kentucky Law Compliant scenario was evaluated. As shown in Figure 6.9.3.1(a), Wilson retires in 2032, while Green remains in service through 2050; however, the portfolio adds more CC generation when Wilson retires to comply with Kentucky's dispatchability requirements. By 2050 in this scenario, the portfolio has 450 MW of CC, 150 MW of storage, and still 800 MW of wind.

Together, the results in Figure 6.9.3.1(a) indicate that the most likely planning futures support long-term operation of Green and Wilson, along with investment in the Green Fuel Oil Backup Project and Wilson reliability projects. While renewable resources are selected in most scenarios for their energy value, the analysis consistently demonstrates the importance of Green as a dispatchable reliability resource and highlights the continued value of the existing generation fleet as the lowest-cost and most resilient portfolios evaluated in the IRP.

Figure 6.9.3.1(a)

Scenario Capacity Expansion Results for Model Optimization Portfolios

Reference Case – Green and Wilson remain in-service through planning period (Installed Capacity (MW))

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
New Solar	0	0	0	0	0	0	0	0	0	0	0	150	500	500	500	500	500	500	500	550	600	600	600	600	600
New Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	50	50	50	50	50	50
Green Fuel Oil Backup	0	0	0	0	68	136	137	139	142	142	142	142	142	142	142	142	142	142	142	142	142	142	142	142	142

Natural Gas Infrastructure Challenges – Green and Wilson remain in-service through planning period (Installed Capacity (MW))

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
New Solar	0	0	0	0	0	0	0	0	100	100	450	450	450	450	450	450	450	450	450	450	450	450	450	450	450
New Wind	0	0	0	0	0	0	0	0	0	0	0	50	50	150	150	150	200	200	200	300	350	350	350	350	350
Green Fuel Oil Backup	0	0	0	0	68	136	137	139	142	142	142	142	142	142	142	142	142	142	142	142	142	142	142	142	142

Low Load and Natural Gas Prices – Wilson retires 2039; Green remains in-service through planning period (Installed Capacity (MW))

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
New CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	150	150	150	150	150	150	150	150	150	150	150
New Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100	100	100	100	100	250	250	250	250	250	250
Green Fuel Oil Backup	0	0	0	0	68	136	137	139	142	142	142	142	142	142	142	142	142	142	142	142	142	142	142	142	142

High Regulatory (Carbon Tax) – Wilson retires 2032; Green remains in-service through planning period (Installed Capacity (MW))

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
New CC	0	0	0	0	0	50	50	300	300	300	300	300	300	300	300	300	300	300	350	350	350	400	400	400	400
New Wind	0	0	0	0	0	0	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800
New 4 Hour Storage	0	0	0	0	0	0	0	0	0	0	0	50	50	100	100	100	150	200	200	200	200	200	200	200	200
Green Fuel Oil Backup	0	0	0	0	68	136	137	139	142	142	142	142	142	142	142	142	142	142	142	142	142	142	142	142	142

High Regulatory (Carbon Tax) Kentucky Law Compliant – Wilson retires 2032; Green remains in-service through planning period (Installed Capacity (MW))

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
New CC	0	0	0	0	0	0	0	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	450	450	450
New Wind	0	0	0	0	0	200	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800
New 4-Hour Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	50	50	50	50	50	100	100	150	150	150	150	150
Green Fuel Oil Backup	0	0	0	0	68	136	137	139	142	142	142	142	142	142	142	142	142	142	142	142	142	142	142	142	142

6.9.3.2 Fixed Retirements – Scenario Result Analysis

The Fixed Retirement portfolios evaluate resource expansion needs assuming Green retires in 2039 and Wilson retires in 2045, requiring the model to cost- effectively identify replacement resources capable of maintaining reliability and resource adequacy. As shown in Figure 6.9.3.2(a), the Green Fuel Oil Backup Project is selected in every scenario, reflecting the continued value of improving Green's reliability and accredited capacity prior to its assumed retirement. In the two most likely planning futures, the Reference Case and Natural Gas Infrastructure Challenges scenarios, the model replaces Green primarily with F-frame combustion turbine capacity and replaces Wilson with a combination of CC and additional combustion turbine capacity. Renewable resources are also added in both scenarios, with the Reference Case reaching approximately 500 MW of solar and 300 MW of wind by 2050, while the Natural Gas Infrastructure Challenges portfolio adds approximately 250 MW of solar and 550 MW of wind, as shown in Figure 6.9.3.2(a). These renewable additions are selected primarily for their energy value, while the thermal additions provide the dispatchable capacity needed to replace the retiring units.

The Low Load and Natural Gas Price scenario results in the fewest resource additions among the portfolios evaluated. As illustrated in Figure 6.9.3.2(a), lower load growth and reduced market prices diminish the need for both replacement capacity and renewable energy additions. Following Green's retirement, the model adds approximately 150 MW of F-frame combustion turbine

capacity, followed by 350 MW of CC generation after Wilson's retirement. Unlike the Reference Case and Natural Gas Infrastructure Challenges portfolios, no economic solar or wind additions are selected under this future, resulting in the simplest replacement portfolio of the scenarios evaluated.

The High Regulatory (Carbon Tax) scenarios produce the largest resource additions and the greatest shift toward renewable generation. As shown in Figure 6.9.3.2(a), both High Regulatory portfolios add approximately 800 MW of wind generation beginning in the early 2030s. The unconstrained High Regulatory portfolio ultimately includes approximately 500 MW of CC generation, 250 MW of CT capacity, and 350 MW of 4-hour battery storage by 2050. Because an unconstrained optimization allows a portion of retiring dispatchable generation to be replaced with non-dispatchable resources, a High Regulatory – Kentucky Law Compliant portfolio was also evaluated. As illustrated in Figure 6.10.3.2(a), the compliant portfolio shifts the timing of building additional dispatchable resources, reaching approximately 450 MW of CC generation, 300 MW of CT capacity, and 300 MW of battery storage by the end of the planning horizon.

Collectively, the Fixed Retirement results shown in Figure 6.9.3.2(a) demonstrate that retirement of Green and Wilson creates a consistent need for substantial replacement generation across all futures, with the amount and type of renewable resources varying based on market, load, and regulatory assumptions.

Figure 6.9.3.2(a)

Scenario Capacity Expansion Results for Fixed Retirement Portfolios

Reference Case - Green retires in 2039 and Wilson retires in 2045 (Installed Capacity (MW))

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
New CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	300	300	300	300	300
New F-Frame CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	250	300	300	300	300	300	400	400	400	400	400
New Solar	0	0	0	0	0	0	0	0	0	0	0	150	500	500	500	500	500	500	500	500	500	500	500	500	500
New Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	50	50	50	50	50	150	300	300	300	300	300
Green Fuel Oil Backup	0	0	0	0	68	136	137	139	142	142	142	142	142	142	142	142	142	142	142	142	142	142	142	142	142

Natural Gas Infrastructure Challenges - Green retires in 2039 and Wilson retires in 2045 (Installed Capacity (MW))

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
New CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	350	350	350	350	350
New F-Frame CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	250	250	250	250	250	250	300	300	300	300	300
New Solar	0	0	0	0	0	0	0	0	150	150	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
New Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	300	300	350	350	350	350	400	550	550	550	550	550
Green Fuel Oil Backup	0	0	0	0	68	136	137	139	142	142	142	142	142	142	142	142	142	142	142	142	142	142	142	142	142

Low Load and Natural Gas Prices - Green retires in 2039 and Wilson retires in 2045 (Installed Capacity (MW))

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
New CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	350	350	350	350	350
New F-Frame CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	150	150	150	150	150	150	150	150	150	150	150
Green Fuel Oil Backup	0	0	0	0	68	136	137	139	142	142	142	142	142	142	142	142	142	142	142	142	142	142	142	142	142

High Regulatory (Carbon Tax) - Green retires in 2039 and Wilson retires in 2045 (Installed Capacity (MW))

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
New CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	150	150	150	150	200	200	500	500	500	500	500
New F-Frame CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	50	100	100	100	250	250	250	250	250
New Wind	0	0	0	0	0	200	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800
New 4-Hour Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	350	350	350	350	350	350	350	350	350	350	350
Green Fuel Oil Backup	0	0	0	0	68	136	137	139	142	142	142	142	142	142	142	142	142	142	142	142	142	142	142	142	142

High Regulatory (Carbon Tax) Kentucky Law Compliant - Green retires in 2039 and Wilson retires in 2045 (Installed Capacity (MW))

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
New CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	150	150	150	150	150	150	400	400	450	450	450
New F-Frame CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100	100	100	100	100	100	300	300	300	300	300
New Wind	0	0	0	0	0	200	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800
New 4-Hour Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100	100	200	250	300	300	300	300	300	300	300
Green Fuel Oil Backup	0	0	0	0	68	136	137	139	142	142	142	142	142	142	142	142	142	142	142	142	142	142	142	142	142

The portfolios for each of the scnearios above were optimized assuming "Fixed Retirements" of Green (2039) and Wilson (2045) as indicated by the years highlighted in blue and purple, respectively

6.10 IRP Results[120]

The analyses described in the Section 6.6 – IRP Framework were developed to evaluate the relative performance, risk, and resilience of alternative resource portfolios across a range of potential future conditions. This section presents the results of the IRP Framework analyses: Scenario Analysis, Cross-Scenario Sensitivity Analysis, Stochastic Analysis, and Scorecard Evaluation and uses those findings to identify a preferred resource portfolio and associated short-term action plan. Together, these analyses provide a comprehensive assessment of portfolio affordability, reliability, risk exposure, and sustainability, allowing Big Rivers to compare alternative resource strategies not only on expected performance but also on their ability to perform under uncertain future market, regulatory, fuel, and load conditions.

6.10.1 Scenario Analysis Results

The Scenario Analysis results are presented using two affordability metrics: PVRR and levelized generation cost ($/Load MWh), as shown in Table 6.10.1(a) and Table 6.10.1(b). PVRR represents the total present value generation cost of serving load over the planning horizon and provides a measure of the overall magnitude of portfolio costs. However, because the scenarios include different load growth assumptions, direct comparison of total PVRR can be misleading. For example, the Low Load and Natural Gas Price scenario naturally produces lower

[120] Responsive to 807 KAR 5:058, Section 9.

total costs because less energy is served over the study period. The levelized generation cost metric, expressed as PVRR divided by total load served, normalizes costs on a $/MWh basis and, therefore, provides a more meaningful comparison of relative affordability across scenarios. For this reason, levelized generation cost serves as the primary affordability metric used to evaluate the IRP results.

Figure 6.10.1(a)

Scenario Analysis Matrix Results
Levelized Generation Cost (PVRR 2026$/Load MWh) 2027 – 2050

		Reference Case*	Natural Gas Infrastructure Challenges*	Low Load and Natural Gas Prices*	High Regulatory (Carbon Tax)	High Regulatory (Carbon Tax) Kentucky Law Compliant
Levelized Generation Cost ($PVRR/Load MWh) 2027-2050	**Model Optimization** Earliest Green can Retire December 31, 2030 Earliest Wilson can Retire December 31, 2032	$68.89	$75.64	$63.33	$102.26	$103.73
		No Green and Wilson Retirement	No Green and Wilson Retirement	No Green Retirement; Wilson 2039	No Green Retirement; Wilson 2032	No Green Retirement; Wilson 2032
	Fixed Retirements Retire and Replace Green December 31, 2039 Retire and Replace Wilson December 31, 2045	$75.33	$85.63	$64.66	$116.89	$116.56
		Green 2039; Wilson 2045	Green 2039; Wilson 2045	Green 2039; Wilson 2045	Green 2039; Wilson 2045	Green 2039; Wilson 2045

Figure 6.10.1(b)

Scenario Analysis Matrix Results
PVRR (2026 $000) 2027 – 2050

		Reference Case*	Natural Gas Infrastructure Challenges*	Low Load and Natural Gas Prices*	High Regulatory (Carbon Tax)	High Regulatory (Carbon Tax) Kentucky Law Compliant
Present Value Revenue Requirements (PVRR $000)	**Model Optimization** Earliest Green can Retire December 31, 2030 Earliest Wilson can Retire December 31, 2032	$4,291	$4,711	$3,444	$7,173	$7,276
		No Green and Wilson Retirement	No Green and Wilson Retirement	No Green Retirement; Wilson 2039	No Green Retirement; Wilson 2032	No Green Retirement; Wilson 2032
	Fixed Retirements Retire and Replace Green December 31, 2039 Retire and Replace Wilson December 31, 2045	$4,692	$5,334	$3,516	$8,200	$8,176
		Green 2039; Wilson 2045	Green 2039; Wilson 2045	Green 2039; Wilson 2045	Green 2039; Wilson 2045	Green 2039; Wilson 2045

As shown in Figure 6.10.1(a), the Model Optimization portfolios outperform the corresponding Fixed Retirement portfolios in every scenario, demonstrating the value of retaining retirement flexibility and the significant capital investment required to replace Green and Wilson under the Fixed Retirement approach. Under the two futures considered most likely to occur, the Reference Case and Natural Gas Infrastructure Challenges scenarios, the Model Optimization portfolios achieve levelized generation costs of $68.89/MWh and $75.64/MWh, respectively, compared to $75.33/MWh and $85.63/MWh for the Fixed Retirement portfolios. These lower costs are driven by the model's ability to retain Green and Wilson in operation, while selecting the Green Fuel Oil Backup Project and Wilson reliability projects, rather than incurring the substantial capital costs associated with constructing replacement generation resources. The results indicate that preserving the existing dispatchable fleet, supported by targeted reliability investments, provides a more economical outcome than retiring and replacing those resources on a predetermined schedule.

The scenario analysis also highlights the influence of alternative future conditions. The Low Load and Natural Gas Price scenario produces the lowest portfolio costs due to reduced load growth and lower commodity prices, while the High Regulatory scenarios produce the highest costs due to the assumed carbon tax. However, even under these bookend futures, the Model Optimization portfolios remain less costly than the corresponding Fixed Retirement portfolios. Collectively, the results shown in Figure 6.10.1(a) and Figure 6.10.1(b) indicate

that portfolios which maintain Green and Wilson in operation for as long as economically optimal consistently provide lower-cost outcomes than portfolios requiring retirement and replacement on a fixed schedule, reinforcing the value of the existing dispatchable fleet within Big Rivers' long-term resource strategy.

6.10.2 Cross-scenario Sensitivity Analysis Results

The Cross-Scenario Sensitivity Analysis evaluates how each optimized portfolio performs when exposed to future conditions different from those used to develop the portfolio. Like the Scenario Analysis, results are presented as PVRR and levelized generation cost ($/Load MWh) in Figure 6.10.2(a) and Figure 6.10.2(b). While PVRR provides an indication of total portfolio cost, the levelized generation cost metric remains the preferred measure for comparing portfolio affordability because it normalizes costs by the amount of load served. This distinction is particularly important when comparing scenarios with different load forecasts. For example, the Low Load and Natural Gas Price portfolios generally produce the lowest total PVRR values because less energy is served throughout the planning horizon. Evaluating costs on a $/MWh basis provides a more meaningful comparison of relative portfolio affordability across differing future conditions.

Figure 6.10.2(a)

Cross-Scenario Sensitivity Analysis Matrix Results
Levelized Generation Cost (PVRR 2026$/Load MWh) 2027 – 2050

Model Optimization	Price Sensitivities -->			
Portfolios ↓	Reference Case	Natural Gas Infrastructure Challenges	Low Load and Natural Gas Prices	High Regulatory (Carbon Tax)
Reference Case	$68.89	$75.67	$65.49	$128.02
Natural Gas Infrastructure Challenges	$70.63	$75.64	$68.32	$126.76
Low Load & Gas Prices	$74.06	$91.34	$63.33	$113.83
High Regulatory (Carbon Tax)	$91.71	$95.61	$79.77	$102.26
High Regulatory (Carbon Tax) Kentucky Law	$93.17	$97.22	$81.47	$103.73

Fixed Retirement	Price Sensitivities -->			
Portfolios ↓	Reference Case	Natural Gas Infrastructure Challenges	Low Load & Gas Prices	High Regulatory (Carbon Tax)
Reference Case	$75.33	$86.73	$68.46	$125.91
Gas Infrastructure Challenges	$76.23	$86.21	$70.37	$129.34
Low Load & Gas Prices	$70.95	$80.83	$64.66	$125.19
High Regulatory (Carbon Tax)	$90.40	$81.21	$84.45	$116.89
High Regulatory (Carbon Tax) Kentucky Law	$89.00	$80.97	$83.29	$116.55

Figure 6.10.2(b)

Cross-Scenario Sensitivity Analysis Matrix Results
PVRR (2026 $000) 2027 – 2050

Model Optimization	Price Sensitivities -->			
Portfolios ↓	Reference Case	Natural Gas Infrastructure Challenges	Low Load and Natural Gas Prices	High Regulatory (Carbon Tax)
Reference Case	$4,290.76	$4,713.48	$4,079.53	$7,973.88
Natural Gas Infrastructure Challenges	$4,399.53	$4,711.52	$4,255.58	$7,895.71
Low Load and Natural Gas Prices	$4,027.55	$4,967.23	$3,443.63	$6,189.75
High Regulatory (Carbon Tax)	$6,432.93	$6,706.79	$5,595.48	$7,173.42
High Regulatory (Carbon Tax) Ky Law	$6,535.54	$6,820.04	$5,715.21	$7,276.19
Fixed Retirement	Price Sensitivities -->			
Portfolios ↓	Reference Case	Natural Gas Infrastructure Challenges	Low Load and Natural Gas Prices	High Regulatory (Carbon Tax)
Reference Case	$4,692.08	$5,402.15	$4,264.02	$7,842.74
Natural Gas Infrastructure Challenges	$4,748.22	$5,369.74	$4,382.97	$8,056.02
Low Load and Natural Gas Prices	$3,858.37	$4,395.60	$3,515.88	$6,807.58
High Regulatory (Carbon Tax)	$6,341.48	$5,696.32	$5,923.87	$8,199.68
High Regulatory (Carbon Tax) Ky Law	$6,243.08	$5,679.79	$5,842.71	$8,175.70

As shown in Figure 6.10.2(a), the Reference Case and Natural Gas Infrastructure Challenges Model Optimization portfolios demonstrate the strong performance in all but the High Regulatory scenario. The Reference Case portfolio produces costs ranging from approximately $68.89/MWh to $75.67/MWh when evaluated under the Reference Case and Natural Gas Infrastructure Challenges assumptions, while the Natural Gas Infrastructure Challenges portfolio produces nearly identical results. These portfolios also consistently outperform the corresponding Fixed Retirement portfolios, reinforcing the value of maintaining flexibility regarding the retirement timing of Green and Wilson. Although the Low Load and Natural Gas Price portfolio appears attractive from a cost perspective, particularly when viewed through total PVRR in Figure 6.10.2(b), that result is misleading because the portfolio was developed under lower load assumptions and does not maintain sufficient resources to satisfy PRM requirements when evaluated under either the Reference Case or Natural Gas Infrastructure Challenges futures. As a result, its lower costs are achieved in part by maintaining a smaller resource portfolio than would be required under the more likely planning futures.

The sensitivity analysis also demonstrates that future regulatory policy represents one of the largest sources of long-term cost uncertainty. Regardless of which portfolio is selected, costs increase significantly when evaluated under the High Regulatory (Carbon Tax) assumptions, as shown in Figure 6.10.2(a) and Figure 6.10.2(b). However, as a whole, the analysis indicates that the Reference

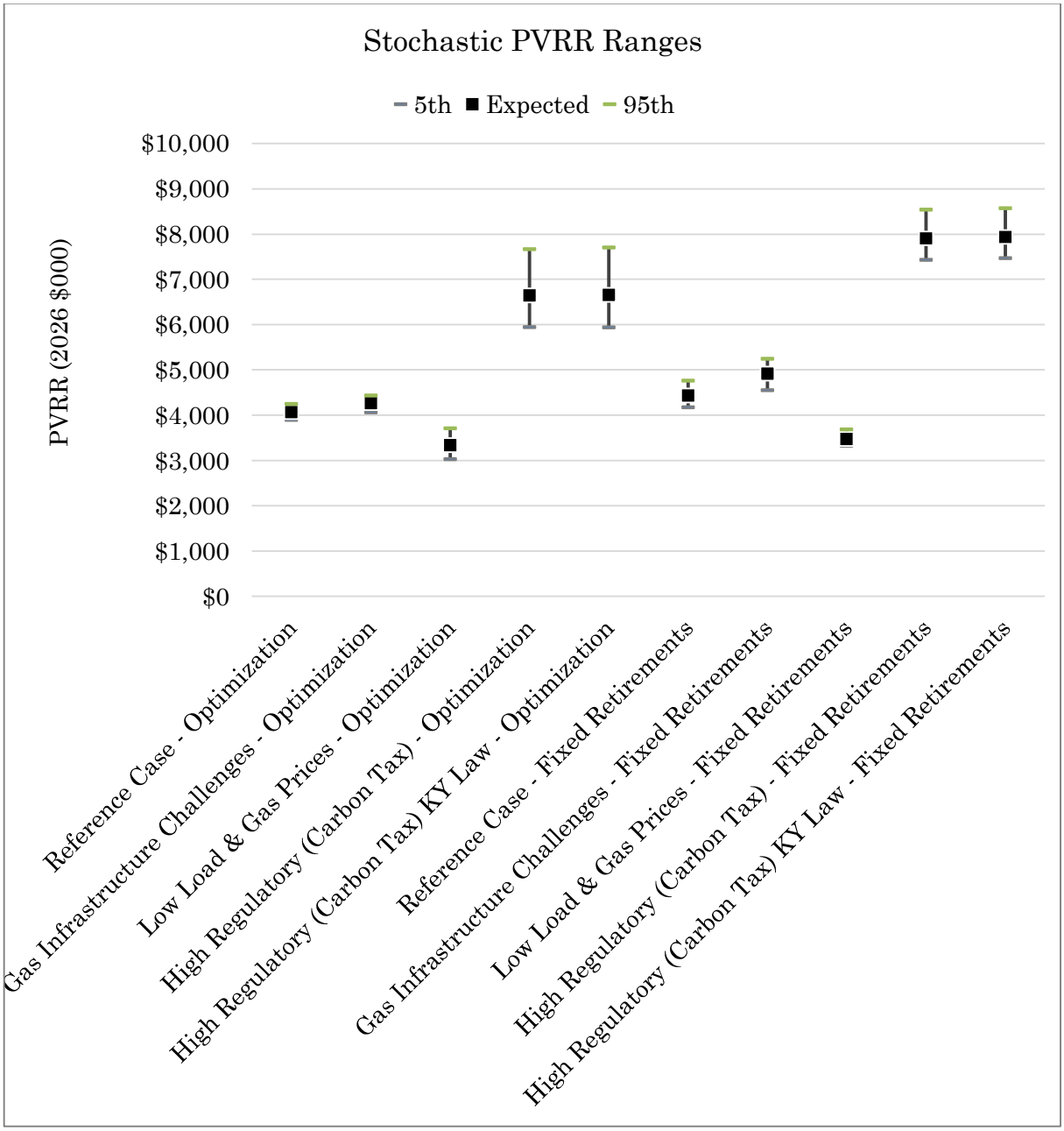
Case and Natural Gas Infrastructure Challenges Model Optimization portfolios provide the best combination of affordability and robustness across the broadest range of plausible future conditions. In particular, the analysis demonstrates that maintaining Wilson through the planning period provides a hedge against natural gas price volatility. These findings are consistent with the Scenario Analysis results and further support portfolios that retain Green and Wilson, while implementing the Green Fuel Oil Backup Project and Wilson reliability projects, as the most resilient long-term resource strategies evaluated in the IRP. Investing in the continued reliability and flexibility of Green and Wilson preserves Big Rivers' most adaptable near-term option while avoiding premature commitment to replacement resources. If regulatory, market, load, fuel-price, or MISO assumptions change, future IRPs can then adjust the timing and composition of new resource additions from a stronger and more flexible starting position.

6.10.3 Stochastic Analysis Results

The stochastic analysis evaluates each portfolio's performance across 100 correlated simulations of future operating conditions. Figure 6.10.3(a) summarizes the resulting distribution of PVRR outcomes for each portfolio, including the 5th percentile (P5), expected, and 95th percentile (P95) values.

Figure 6.10.3(a)

Stochastic Analysis Results
PVRR (2026 $000) 2027 – 2050



Several important observations emerge from the stochastic analysis. First, the Model Optimization portfolios consistently outperform the corresponding Fixed Retirement portfolios, reinforcing the findings from the Scenario and Cross-

Scenario Sensitivity Analyses. The Reference Case and Natural Gas Infrastructure Challenges Model Optimization portfolios exhibit among the lowest expected PVRR values while maintaining relatively narrow ranges between the 5th and 95th percentile outcomes. These portfolios benefit from retaining the peaking energy from Green and baseload energy from Wilson, avoiding the need for significant investment in replacement resources. As a result, they exhibit lower expected costs and lower exposure to uncertainty than the corresponding Fixed Retirement portfolios. Although the Low Load and Natural Gas Price Model Optimization portfolio produces the lowest expected PVRR, it is optimized for a future with lower load growth and would not satisfy planning reserve requirements under the more likely Reference Case and Natural Gas Infrastructure Challenges futures.

The High Regulatory (Carbon Tax) portfolios exhibit both the highest expected PVRR values and the widest ranges of stochastic outcomes. These results reflect the combined effects of the carbon tax assumptions and the increased reliance on new renewable and replacement resources identified through the capacity expansion analysis. Because weather influences renewable generation, load, and wholesale power prices simultaneously, portfolios with greater dependence on these resources exhibit greater variability across the stochastic simulations.

Overall, the stochastic analysis is consistent with the broader IRP findings. The Reference Case and Natural Gas Infrastructure Challenges Model

Optimization portfolios provide the most favorable combination of affordability and risk, while portfolios that retain Green and Wilson for a longer period exhibit lower expected costs and narrower ranges of potential outcomes than portfolios with fixed retirement schedules.

6.10.4 Scorecard Evaluation

The IRP Scorecard provides a comprehensive comparison of portfolio performance across the four planning objectives of affordability, reliability, risk and opportunity, and sustainability. The Scorecard combines the results of the Scenario Analysis, Cross-Scenario Sensitivity Analysis, and Stochastic Analysis to assess the overall strengths and weaknesses of each resource strategy. As shown in Figure 6.10.4(a), the results consistently favor the Model Optimization Reference Case portfolio, with the Model Optimization Natural Gas Infrastructure Challenges portfolio also performing strongly across most evaluation categories.

Figure 6.10.4(a)

IRP Scorecard

		Affordability (Reference Case Assumptions)				Reliability		Risk and Opportunity		Sustainability
	Portfolio	**15-Year Levelized Generation Cost ($/MWh 2027-2041)**	**Full Study Levelized Generation Cost ($/MWh 2027 - 2050)**	**15-Year PVRR ($MM 2027 - 2041)**	**Full Study PVRR ($MM 2027 - 2050)**	**Dispatchable Capacity Divided by Big Rivers Winter CP 2046**	**Dispatchable Firm Capacity Divided by Big Rivers Winter CP 2046**	**Opportunity: Stochastic P5 Full Study ($/MWh 2027-2050)**	**Risk: Stochastic P95 Full Study ($/MWh 2027-2050)**	**Total CO_2 Emissions (Million Tons)**
Model Optimization	Reference Case	$65.03	$68.89	$2,982	$4,291	161%	106%	$66.11	$71.77	92.5
	Natural Gas Infrastructure Challenges	$66.12	$70.63	$3,032	$4,400	161%	106%	$67.36	$73.32	90.1
	Low Load and Natural Gas Prices	$65.82	$74.06	$2,743	$4,028	163%	102%	$68.35	$80.91	66.2
	High Regulatory (Carbon Tax)	$86.38	$91.71	$4,325	$6,433	124%	81%	$81.73	$106.23	46.8
	High Regulatory (Carbon Tax) Kentucky Law	$88.99	$93.17	$4,456	$6,536	130%	85%	$82.92	$108.03	47.6
Fixed Retirements	Reference Case	$65.74	$75.33	$3,014	$4,692	120%	95%	$71.17	$80.58	79.9
	Natural Gas Infrastructure Challenges	$66.69	$76.23	$3,058	$4,748	113%	90%	$70.38	$81.47	79.6
	Low Load and Natural Gas Prices	$63.96	$70.95	$2,665	$3,858	121%	96%	$68.20	$74.78	79.3
	High Regulatory (Carbon Tax)	$81.07	$90.40	$4,059	$6,341	103%	82%	$83.64	$99.57	75.4
	High Regulatory (Carbon Tax) Kentucky Law	$80.43	$89.00	$4,028	$6,243	98%	78%	$82.30	$98.10	74.8

The affordability metrics warrant particular attention because both Present Value Revenue Requirements ("PVRR") and levelized generation cost ($/Load MWh) are presented. While PVRR measures the total present value cost of serving load, the $/MWh metric provides the more meaningful comparison of relative affordability because it normalizes costs by the amount of energy served. This distinction is particularly important when comparing portfolios developed under different load forecasts, as a lower PVRR does not necessarily indicate a more economical portfolio on a comparable basis. To facilitate an apples-to-apples comparison, the affordability metrics shown in Figure 6.10.4(a) evaluate all portfolios using common Reference Case market assumptions while preserving each portfolio's unique resource build strategy. Under this consistent evaluation framework, the Model Optimization Reference Case portfolio emerges as one of the lowest-cost and most practical resource strategies.

The Scorecard's reliability and risk metrics further reinforce this conclusion. The Model Optimization Reference Case portfolio maintains some of the highest levels of dispatchable and accredited firm capacity by retaining both Green and Wilson throughout the planning horizon while implementing the Green Fuel Oil Backup Project and the Wilson reliability improvements. This portfolio provides sufficient excess dispatchable and accredited capacity above Big Rivers' forecasted coincident summer peak load beginning in 2029 and coincident winter peak load beginning in 2032. This capacity surplus is maintained through the remainder of the planning horizon and serves as a hedge against forecast error, changes in MISO

resource accreditation methodologies, and unexpected operational events. As a result, the portfolio's reliability value extends beyond compliance with current planning requirements and provides additional system resilience under a range of future conditions.

The portfolio also demonstrates a favorable risk profile. The P5 and P95 metrics shown in the Scorecard incorporate the relative risk impacts identified through the Stochastic Analysis by applying each portfolio's upside and downside cost deviations to the common Reference Case affordability results. This approach maintains a consistent affordability basis across portfolios while transparently reflecting the relative uncertainty associated with each resource strategy. Consistent with the stochastic analysis, the Model Optimization Reference Case portfolio exhibits relatively low expected costs and a narrower range of potential outcomes than the alternative portfolios.

In contrast, the High Regulatory portfolios exhibit greater cost uncertainty because they rely more heavily on new replacement generation, including CC resources and significant wind additions. The economics of the CC resources depend on future energy market revenues, natural gas prices, and dispatch levels, while increased reliance on wind generation introduces additional uncertainty associated with weather-driven renewable output. Because the stochastic analysis preserves the relationships among weather, load, natural gas prices, wholesale power prices, and renewable generation, these portfolios exhibit a wider

distribution of potential cost outcomes than portfolios that retain Green and Wilson for a longer period.

While the High Regulatory portfolios perform best from an emissions perspective, they do so at substantially higher cost and with lower dispatchable capacity margins.

When all scorecard categories are considered together, the Model Optimization Reference Case portfolio provides the strongest overall balance of affordability, reliability, and risk management. Therefore, the results shown in Figure 6.10.4(a) reinforce the conclusions reached throughout the IRP: maintaining Green and Wilson in operation, supported by the Green Fuel Oil Backup Project and Wilson reliability projects, represents the most prudent and resilient long-term resource strategy under the futures considered most likely to occur.

6.11 IRP Preferred Resource Portfolio and Short-Term Action Plan

6.11.1 Preferred Resource Portfolio

The results of the Scenario Analysis, Cross-Scenario Sensitivity Analysis, Stochastic Analysis, and IRP Scorecard consistently identify the Model Optimization Reference Case portfolio as the Preferred Resource Portfolio. Across the futures considered most likely to occur, this portfolio provides the strongest combination of affordability, reliability, and risk management while preserving flexibility to respond to changing market, regulatory, and load conditions.

A central finding of the IRP is that continued operation of Green and Wilson is more economical than retiring and replacing these resources on a fixed schedule. The preferred portfolio includes implementation of the Green Fuel Oil Backup Project and the Wilson reliability projects, both of which were consistently selected in the most likely futures and provide significant reliability and resource adequacy benefits. The portfolio also supports the addition of renewable resources over time as economically justified, primarily to provide energy value and reduce market purchases while maintaining the existing dispatchable fleet as the foundation of system reliability.

The preferred portfolio performed favorably across all major evaluation criteria. It achieved the lowest costs among the most likely futures, produced the strongest reliability margins, demonstrated favorable performance under alternative future conditions, and exhibited a narrower range of potential outcomes in the stochastic analysis than portfolios requiring earlier retirement of existing dispatchable resources. Collectively, these results indicate that maintaining Green and Wilson while making targeted reliability investments represents the most balanced and resilient long-term resource strategy available to Big Rivers.

6.11.2 Short-Term Action Plan

To implement the Preferred Resource Portfolio, Big Rivers should focus on the following near-term actions:

1. Request Commission approval to retire the Reid CT, indicating that accredited capacity improvements resulting from the Green Fuel Oil Backup Project satisfy KRS 278.264's requirement for replacement of the unit.

2. Seek a Certificate of Public Convenience and Necessity from the Commission and if the CPCN is granted proceed with the Green Fuel Oil Backup Project to improve winter fuel assurance, accredited capacity, and operational flexibility, allowing planning flexibility to continue monitoring future conditions that could necessitate capacity additions after 2031.

3. Proceed with planning and execution of the reliability projects at Wilson.

4. Implementation of cost-effective DR pilot programs identified through the MPS.

5. Monitor evolving MISO resource adequacy requirements, accreditation methodologies, and seasonal planning reserve requirements and adjust resource plans as necessary.

6. Monitor large-load development opportunities, data center growth, natural gas infrastructure constraints, and regulatory developments that could materially affect future resource needs.

7. Reassess future renewable and dispatchable resource additions through subsequent IRP cycles to ensure resource decisions reflect the

latest market conditions, technology developments, and member requirements.

6.12 Conclusion[121]

The 2026 IRP demonstrates that Big Rivers can continue to provide reliable and affordable service while managing uncertainty associated with future load growth, commodity prices, market conditions, and regulatory developments. Across the analyses performed, portfolios that retain Green and Wilson for a longer period consistently outperform portfolios that require fixed retirement and replacement of those resources. The results show that the existing dispatchable fleet continues to provide significant economic and reliability value to Big Rivers' system.

The IRP further demonstrates the importance of targeted reliability investments. The Green Fuel Oil Backup Project materially improves winter fuel assurance and accredited capacity. In addition, the accreditation benefits associated with the Green Fuel Oil Backup Project, combined with projected DSM savings, effectively offset the loss of Reid and [redacted]. Investing in the continued reliability and flexibility of Green and Wilson preserves Big Rivers' most adaptable near-term option while avoiding premature commitment to replacement resources. If regulatory, market, load, fuel-price, or MISO assumptions change, future IRPs can adjust the timing

[121] Responsive to 807 KAR 5:058, Section 5.

and composition of new resource additions from a stronger and more flexible starting position.

While renewable resources are selected in several scenarios and continue to provide economic energy value, the analysis consistently shows that dispatchable generation remains essential to maintaining resource adequacy and system reliability. Therefore, the Preferred Resource Portfolio balances existing dispatchable resources, incremental renewable additions, demand-side resources, and future optionality to create a resilient long-term strategy.

Accordingly, Big Rivers concludes that continued operation of Green and Wilson, supported by targeted reliability investments and ongoing DSM efforts, represents the most prudent long-term resource strategy for serving its members. The portfolio not only minimizes long-term costs and satisfies applicable reliability requirements, but also provides sufficient excess dispatchable and accredited capacity above Big Rivers' forecasted coincident summer peak load beginning in 2029 and coincident winter peak load beginning in 2032. That surplus capacity is maintained through the remainder of the planning horizon and provides a valuable reliability buffer against load forecast uncertainty, future modifications to MISO's resource adequacy framework, and changes in resource accreditation or operating performance. As a result, the preferred portfolio provides not only one of the lowest-cost paths forward, but also one of the most resilient and flexible resource strategies evaluated in this IRP.

CHAPTER 7

TRANSMISSION PLANNING



7. TRANSMISSION PLANNING[122]

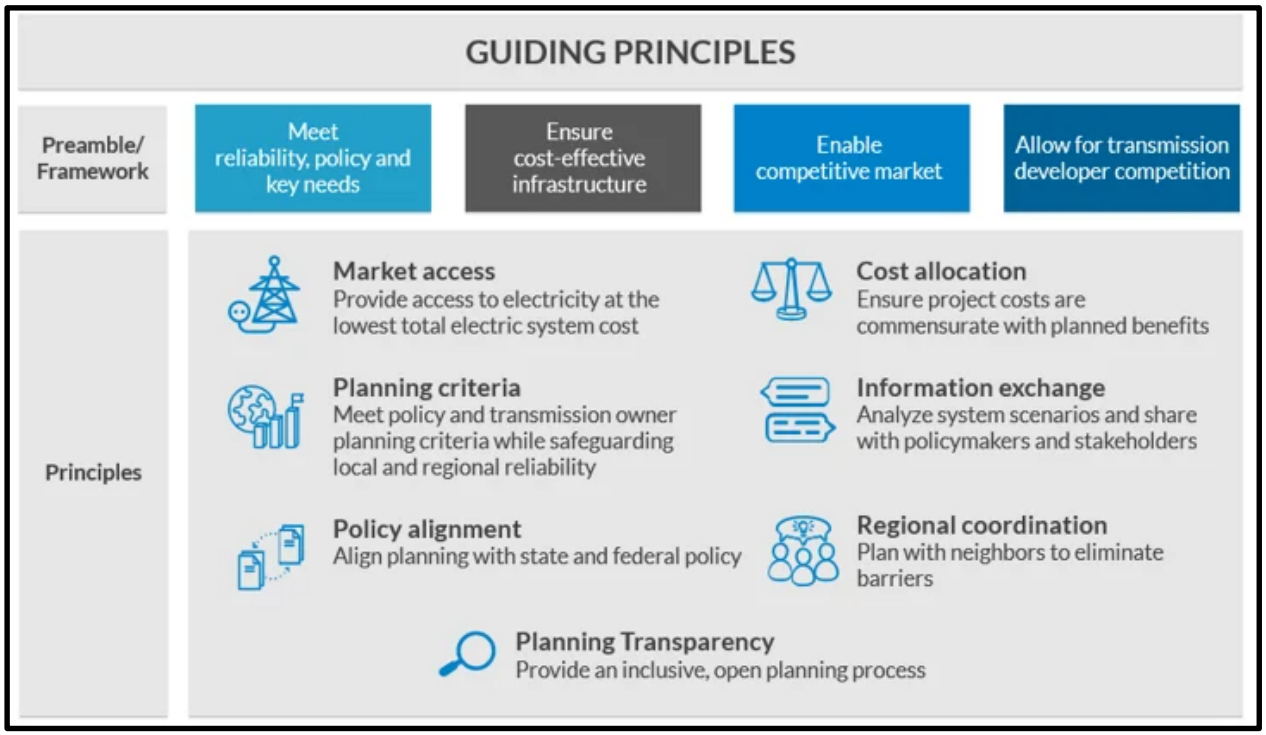
The Big Rivers transmission system consists of the physical facilities necessary to transmit power from its generating plants and interconnection points to all substations from which customers of its three Members are served. Transmission planning embodies making investment decisions required to maintain 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.

7.1 MISO Transmission Planning

As a member of MISO, Big Rivers participates in MISO's coordinated near–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

[122] Responsive to 807 KAR 5:058, Section 5(1).

provide input on the transmission system. The Guiding Principles of the MISO Transmission Expansion Planning process follow:



7.2 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 and real-time experiences, Big Rivers can import sufficient generation to satisfy all its system firm demand requirements.

With respect to the optimization and expansion of the existing Big Rivers transmission system during the period from 2024 through 2026, Big Rivers installed approximately 52 miles of new Optical Ground Wire (OPGW) used to improve telecommunication and protection across the transmission system, added new interconnection facilities at three existing Big Rivers substations to connect four-foreign owned solar farms (total 760MW), and built a new Transmission Operation Center Facility which includes a new state of the art hardened Primary Control Center used to operate and control the entire Big Rivers System.

Additionally, Big Rivers facility ratings methodology and practices are reviewed annually. Big Rivers will expand their existing Ambient Adjusted Ratings ("AAR") conductor ratings to include all terminal equipment following FERC Order 881. This new regulation aims 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 7.2(a) and Planned System Additions Table 7.2(b).

Table 7.2(a)

Completed Transmission System Additions (2024 – 2026)

Project Description	Year
OPGW Installation	2024
McCracken Co., Hopkins Co., and Daviess Co. Relay Upgrades	2024
Reid 161 kV Sub Terminal Addition (Unbridled Solar)	2024
OPGW Installation	2025
New Transmission Operation Center (TOC)	2025
West Paducah Substation Circuits (3)	2025
Meade County Sub Terminal Addition (Green River Solar)	2025
Reid EHV 161 kV Sub Terminal Addition (Sebree Solar)	2025
Bon Harbor to OMU Sub 'M' 69 kV T-Line	2026
Henderson Co. Capacitor Bank Installation	2026
OPGW Installation	2026

Table 7.2(b)

Planned Transmission System Additions (2027-2041)

Project Description	Year
[redacted]	

CHAPTER 8

RESOURCE ADEQUACY AND PLANNING



8. RESOURCE ADEQUACY AND PLANNING

Following receipt of the Commission's permission in Case No. 2010-00043,[123] 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.

8.1 MISO Footprint

MISO operates a massive high-voltage transmission system stretching across fifteen U.S. states and the Canadian province of Manitoba and serves approximately forty-five (45) million people across its footprint.[124] MISO divides its footprint into Local Resource Zones ("LRZs") to ensure local electricity generation matches regional demand. Big Rivers is located in MISO's LRZ 6, which is comprised of most of Indian

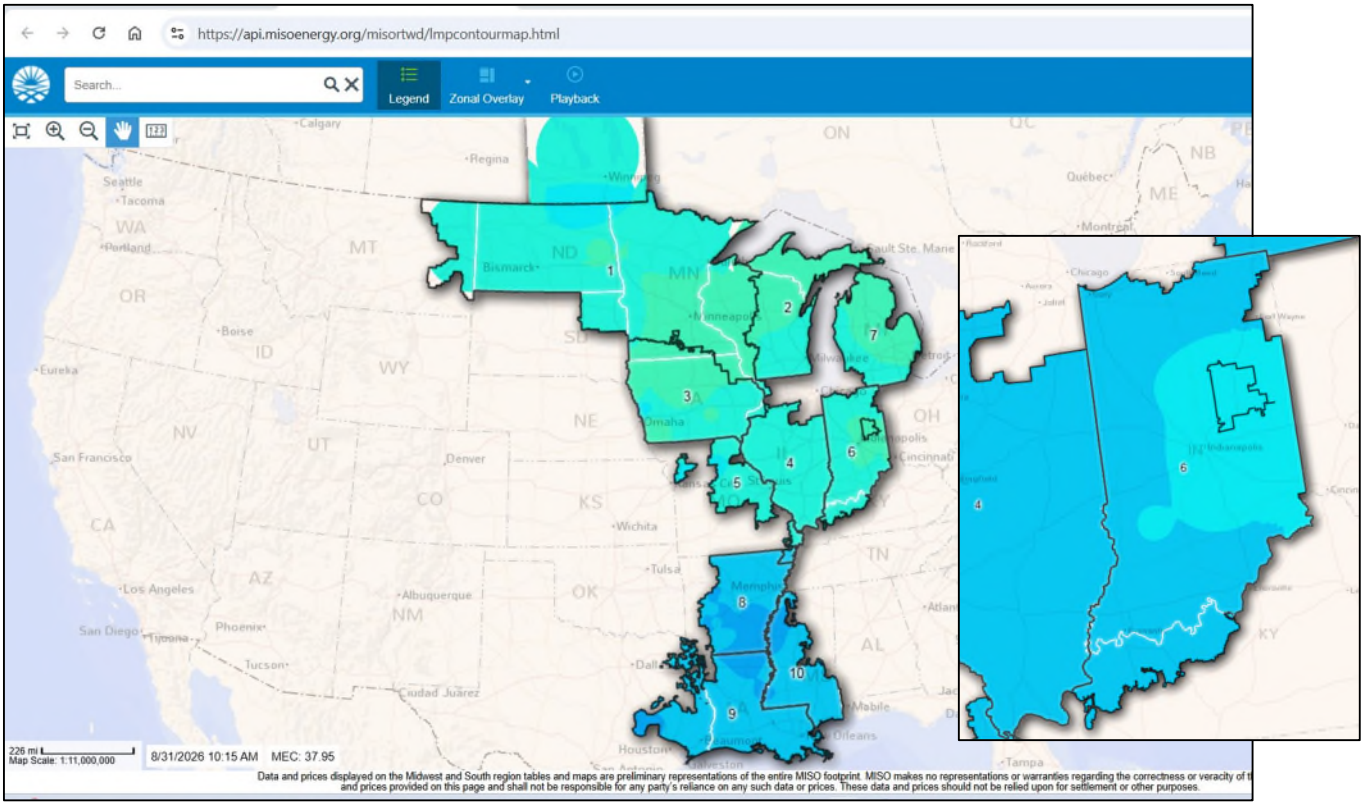
[123] *See In the Matter of: Application of Big Rivers Electric Corporation for Approval to Transfer Functional Control of its Transmission System to Midwest Independent Transmission System Operator, Inc.* - Case No. 2010-00043 (Ky. P.S.C. November 1, 2010). Subsequent to this proceeding, MISO changed its name from Midwest Independent Transmission System Operator, Inc., to Midcontinent Independent System Operator, Inc.

[124] Midcontinent Indep. Sys. Operator, Inc., *About MISO*, https://www.misoenergy.org/meet-miso/about-miso (last visited Aug. 31, 2026).

and northwest Kentucky, as shown in Figure 8.1(a) *MISO Local Resource Zone Map* below.

Figure 8.1(a)

MISO Local Resource Zone Map[125]



8.2 Winter Storm Reliability and Green Fuel Oil Backup Value

Large multi-regional winter storms create compounded reliability risk through extended high load, increased forced outage risk, natural gas fuel constraints, lower renewable output, and constrained regional import capability. NERC notes that natural-gas-fired generation is increasingly critical to system

[125] Figure 8.1(a), Zone Map, provides MISO entire system footprint disaggregated by Local Resource Zone (LRZ). Big Rivers operates in MISO LRZ 6.

reliability and that secure fuel supplies are important during extreme electricity demand.[126] SERC similarly identifies fuel availability and natural gas transportation risk during extreme cold weather and notes that dual-fuel capability can provide resilience.[127] MISO's Winter Storm Fern review demonstrated these risks: extreme cold, snow, and ice contributed to forecast errors, unit availability issues, and low wind production; MISO declared two Maximum Generation Step 2c events in the North and Central regions to access emergency ranges, Load Modifying Resources (LMRs), and emergency power purchases.[128] MISO also reported persistent negative capacity margins on January 24, 2026.[129]

NERC reports that data centers and other large commercial and industrial loads account for most projected North American electricity demand growth over the next decade, while many assessment areas are adding gas-fired capacity.[130]

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[126] N. Am. Elec. Reliability Corp. (NERC), *2025 Long-Term Reliability Assessment* (Jan, 2026) (Executive Summary; Resource Mix Changes discussion, including fuel-supply disruptions, natural-gas reliance, and the value of secure fuel supplies during periods of extreme electricity demand).

[127] SERC Reliability Corp. (SERC), 2*024-2034 Annual Long-Term Reliability Assessment Report,* at 20, 29, 43 (discussing resource vulnerabilities during extreme cold, natural gas supply/transportation risk, dual-fuel capability, and firm gas arrangements).

[128] (MISO, *Overview of Winter Storm Fern, Reliability Subcommittee.* (Feb. 17, 2026), slide 2 (describing extreme cold, snow, ice, forecasting errors, unit availability issues, low wind production, and two Maximum Generation Step 2c events).

[129] MISO, *Overview of Winter Storm Fern, Reliability Subcommittee*, (Feb. 17, 2026) slides 5-6 (describing negative capacity margins, emergency actions, significant unplanned outages, and CT lead-time impacts on real-time commitments and accreditation).

[130] NERC, *2025 Long-Term Reliability Assessment, January 2026, Executive Summary and Demand Trends and Implications*, at 9, 27 (discussing projected North American demand growth driven by data centers and other large commercial and industrial loads, and natural-gas-fired capacity additions across assessment areas).

SERC reports that natural gas remains the primary regional fuel source.[131] This combination is likely to increase competition for gas supply and transportation during winter periods when electric demand, heating demand, and generator fuel needs are highest. Winter Storm Fern demonstrated the exposure: the Independent Market Monitor ("IMM") reported approximately 18 Bcf of gas supply disruptions from wellhead freeze-offs, impacts across nearly all gas pipelines, Henry Hub prices above $30/MMBtu, and 2.6 GW of gas units unavailable for fuel-related reasons.[132] MISO's market review found that high gas prices and capacity sufficiency concerns increased costs and uplift, with gas unit real-time offers averaging up to approximately $450/MWh on January 24 and emergency resources setting ex-post prices at an Emergency Offer Floor of approximately $2,000/MWh.[133] MISO's shortage-pricing reforms allow prices, or Value of Lost Load (VOLL), to rise to $10,000/MWh, compared with the prior $3,500/MWh value. Dual-fuel capability and firm fuel arrangements provide a practical resilience hedge against gas-delivery

[131] SERC, *2024-2034 Annual Long-Term Reliability Assessment Report*, at 21 (identifying natural gas as the primary fuel source in the SERC region and 8.1 GW of Tier 1 plus 17 GW of Tier 2 additional natural gas generation during the assessment period).

[132] Potomac Econ., *IMM Quarterly Report: Winter 2026,* presented to the MISO Markets Comm. of the Bd. of Dirs. (Mar. 24, 2026), slides 7, 47, 60 (describing Winter Storm Fern gas supply disruptions, pipeline impacts, Henry Hub prices, fuel-related outages, and 2.6 GW of gas units unavailable for fuel issues).

[133] MISO, M*arket Outcomes of Winter Storm Fern,* Market Subcomm. (Apr. 16, 2026), slides 2, 4, 5 (describing high natural gas prices, challenged capacity sufficiency, gas unit offers averaging up to approximately $450/MWh, and emergency pricing at an Emergency Offer Floor of approximately $2,000/MWh).

risk, accreditation erosion, and volatile reliance on market purchases during regional stress events.[134]

For Big Rivers, the Green resources are not currently dual-fuel resources and may face natural gas delivery constraints during winter storms and other constrained gas-delivery periods. The primary value of dual-fuel CT capability is fuel assurance and operational optionality during high-risk reliability hours, not for routine energy production. That optionality is likely to become more valuable as national load growth accelerates and new resource additions rely more heavily on natural gas. Adding fuel oil backup would also improve winter availability and corresponding capacity accreditation value.

8.3 SERC IRP Report and Wilson Reliability Projects

Big Rivers references SERC's 2024-2034 Annual Long-Term Reliability Assessment as an independent regional reliability study supporting the continued need for accredited, dispatchable capacity in the SERC MISO-Central subregion. SERC identifies MISO-Central as a summer-peaking subregion that includes all or parts of Illinois, Iowa, Kentucky, including Big Rivers, and Missouri.[135] [136] SERC

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[134] MISO, *Energy and Operating Reserve Markets Business Practices Manual*, BPM-002-r26, Section 5.2.1, at 194 (effective Sept. 30, 2025) (stating that Pricing VOLL defaults to $10,000/MWh); Potomac Economics, IMM *Quarterly Report: Winter 2026*, slide 5(noting MISO's September 2025 shortage-pricing reforms and $10,000/MWh VOLL shortage intervals).

[135] SERC, *2024-2034 SERC Annual Long-Term Reliability Assessment Report*, at3-4(describing the report 's evaluation of resource and transmission adequacy across the SERC region for the next ten years and the report's assessment process).

[136] SERC, *2024-2034 SERC Annual Long-Term Reliability Assessment Report,* at 70. Appendix D of the SERC report lists Big Rivers Electric Corporation as a cooperative member with MISO-Central affiliation.

evaluates resource adequacy using Anticipated Reserve Margins (ARM) compared with a 15% NERC Reference Margin Level. For MISO-Central, SERC's dashboard shows summer ARMs below the 15% level in 2024, 2025, 2033, and 2034.[137] [138]

Table 8.3(a) SERC MISO-Central

Anticipated reserve margins vs. 15% NERC Reference Margin Level[137] [138]

Metric	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Summer ARM	-2%	-1%	8%	18%	20%	19%	17%	17%	17%	12%	12%
Winter ARM	16%	15%	22%	29%	30%	30%	26%	25%	25%	20%	20%
Summer vs. 15%	Below	Below	Below	Above	Above	Above	Above	Above	Above	Below	Below
Winter vs. 15%	Above	At Target	Above	Above	Above	Above	Above	Above	Above	Above	Above

SERC links the lower MISO-Central reserve-margin outlook to generation retirements and the changing resource mix. Coal represents the largest share of existing on-peak summer capacity in MISO-Central at 45%, but more than 9.1 GW of coal generation is expected to retire over the assessment period. SERC identifies retirement replacement of only approximately 0.6 GW of Tier 1 natural gas and 3.4 GW of BES-connected solar additions and concludes that resource additions are not

[137] SERC, *2024-2034 SERC Annual Long-Term Reliability Assessment Report*, at 23-25. Section 6 defines Planning Reserve Margins and the 15% NERC Reference Margin Level.

[138] SERC, *2024-2034 SERC Annual Long-Term Reliability Assessment Report*, at 48-51. MISO-Central dashboard and highlights, including summer and winter reserve margins, the 45% coal share, expected coal retirements, Tier 1 additions, MISO Regional Directional Transfer Limit caveat, and reliability issues.

keeping pace with retirements and demand growth. SERC also cautions that coal-to-solar replacement must be evaluated for essential reliability services, including frequency response, balancing service, voltage control, blackstart capability, and ramping support. The SERC report does not expressly mention D.B. Wilson Station; however, its findings support Big Rivers' IRP rationale for continued reliability-focused investment in Wilson. Maintaining Wilson's reliable, dispatchable capacity supports regional resource adequacy in SERC and provides essential reliability benefits to Big Rivers' service territory.

CHAPTER 9
ACTION PLAN



9. ACTION PLAN

The Reference Case portfolio for the 2026 IRP includes a mix of resources that includes coal, natural gas with fuel oil backup, hydro, and solar. This diverse mix of resources produces the least cost portfolio while maintaining reliable baseload energy for our 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 to certain actions now or at any future date.

Big Rivers' most recent Financial Plan, which was approved by its Board in December 2025, included projected Member rates as shown in Table 9(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 Reference Case scenario is to continue operating through 2050 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 9(a)

Actual and Projected Big Rivers' Wholesale Rates



9.1 Action Plan Detail

Big Rivers' 2026 IRP analysis results in a base portfolio to include Wilson continuing operation and implementation of the reliability projects, Green 1 and Green 2 adding fuel oil backup to improve winter capacity accreditation, retirement of the Reid CT, continuing the SEPA hydropower contract, as well as the Unbridled solar power purchase agreement, and the addition of DSM over the planning period.

The Reference Case includes all existing Big Rivers resources continuing in service through at least 2050 except for the Reid CT and the Unbridled PPA that expires in 2045. As discussed in Section 6.7.7, Green Fuel Oil Backup, of this IRP, retrofitting the Green units for fuel assurance will add approximately 144 MWs of winter capacity accreditation, and the DSM portfolio contributes approximately 17 MW of winter peak demand reduction in 2033.[139] In addition, continued operation of Wilson and implementation of the reliability projects preserve significant accredited dispatchable capacity throughout the planning horizon. This results in sufficient capacity to meet customer demand and MISO resource adequacy requirements.

Big Rivers will take the following actions to implement the Reference Case portfolio:

- Submit a request to the Commission for approval to retire the Reid CT.

[139] The 17 MWs of winter peak demand reduction is projected to decline slightly over the balance of the planning period to approximately 15 MWs.

- Submit to the Commission the required requests for a Certificate of Public Convenience and Necessity at the appropriate time in advance of pursuing the Green Fuel Oil Backup Project.
- Implement reliability projects at Wilson over the next several years to ensure long-term reliability
- Continue with evaluation of cost-effective DSM programs in partnership with our Member Cooperatives.

Big Rivers will continue to monitor industry and regulatory changes that could impact the effectiveness of the Reference Case portfolio and adjust plans as needed. Future IRPs will re-evaluate this portfolio, but today, it is among the lowest cost options to continue providing reliable service to our Member-Owners.

APPENDICES



APPENDIX A

LONG-TERM LOAD FORECAST REPORT

2025 Load Forecast Report

PREPARED FOR:

BIG RIVERS ELECTRIC CORPORATION



PREPARED BY:

CLEARSPRING ENERGY ADVISORS

NOVEMBER 2025



Clearspring Energy Advisors LLC

2025 Big Rivers Electric Corporation
Load Forecast Study

November 12, 2025

Prepared By:



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Confidentiality Statement

The information contained in this document shall not be duplicated, used in whole or in part for any purpose other than the express purpose for which it was intended. No information presented herein shall be disclosed outside of the intended parties to this document.

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1 INTRODUCTION AND SYSTEM SUMMARY

1.1 PROJECT OVERVIEW

The 2025 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 2025 electric load forecast through 2044. 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

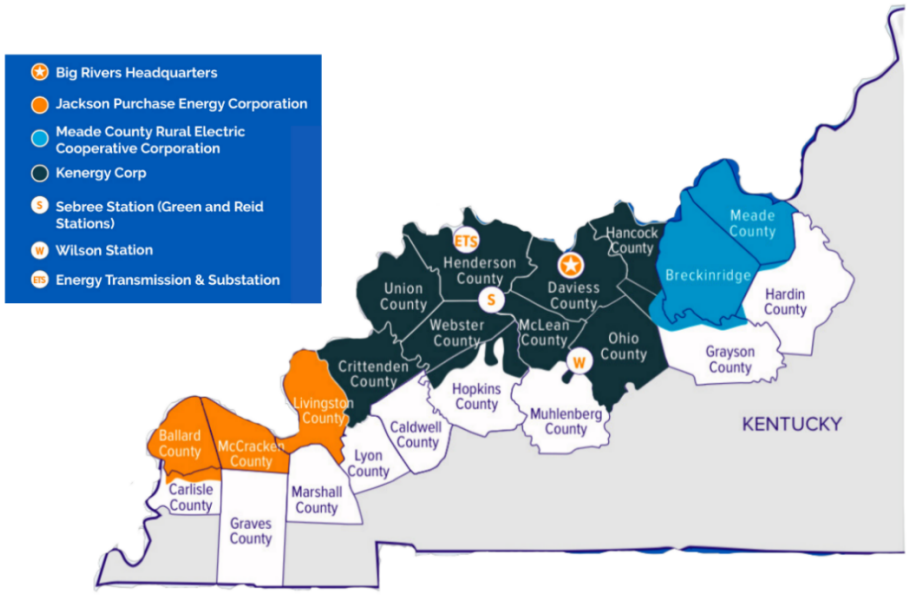
Name	Company	Role
Ryan Wilhelmus	Big Rivers Electric Corporation	Project Manager
Russ Pogue	Big Rivers Electric Corporation	DSM Study
Travis Spiceland	Jackson Purchase Energy Corporation	Load Forecast Representative
Meredith Kendall	Jackson Purchase Energy Corporation	Load Forecast Representative
Tim Lindahl	Kenergy 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

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 (2020-2024) and the forecasts for the next 20 years.

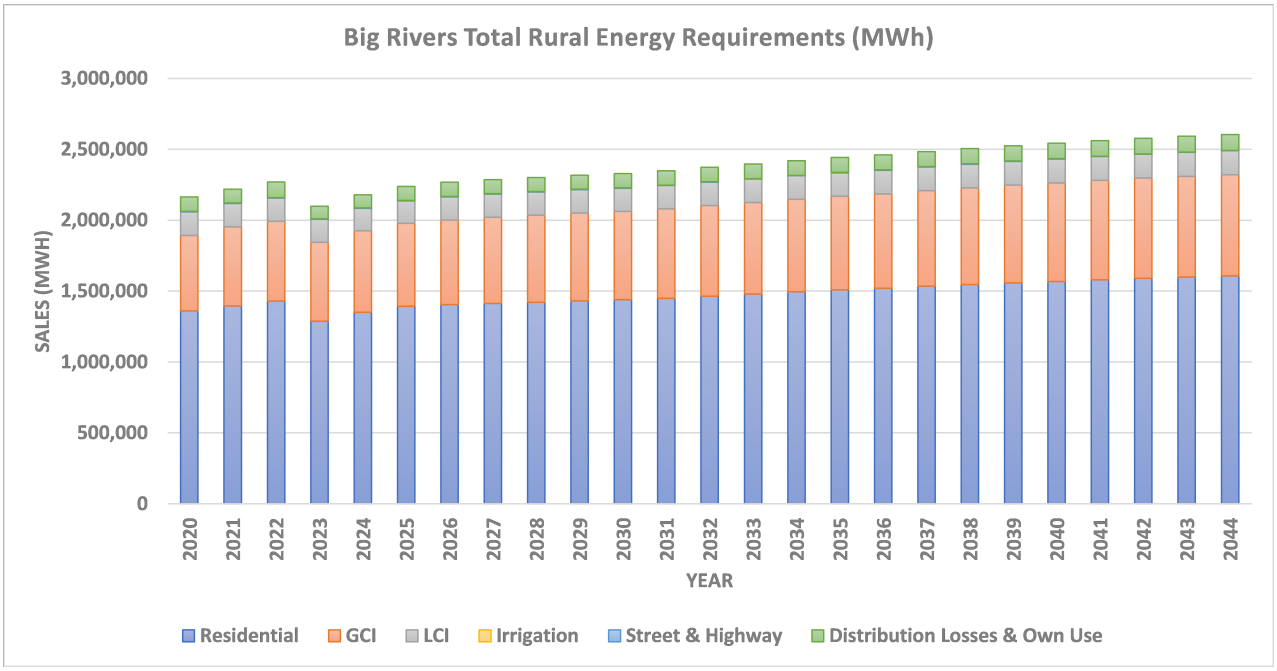
Native System Summary[1]

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
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	811,577	598.3	88.5	43.3%	51.3%
2023	2,097,660	1,167,083	490.4	225.4	48.8%	52.1%
2024	2,179,785	1,623,201	486.3	262.2	51.0%	57.8%
2025	**2,238,259**	**1,785,062**	**455.2**	**267.2**	**56.1%**	**63.6%**
2026	**2,267,529**	**1,842,767**	**460.5**	**273.4**	**56.2%**	**63.9%**
2027	**2,285,503**	**1,861,031**	**463.7**	**276.1**	**56.3%**	**64.0%**
2028	**2,301,046**	**1,863,066**	**466.2**	**276.6**	**56.2%**	**63.8%**
2029	**2,317,481**	**1,867,091**	**468.9**	**277.4**	**56.4%**	**64.0%**
2030	**2,328,667**	**1,871,556**	**470.4**	**278.2**	**56.5%**	**64.0%**
2031	**2,347,896**	**1,876,179**	**473.6**	**279.1**	**56.6%**	**64.1%**
2032	**2,372,775**	**1,880,236**	**477.9**	**279.9**	**56.5%**	**63.9%**
2033	**2,395,795**	**1,884,854**	**482.1**	**280.8**	**56.7%**	**64.0%**
2034	**2,420,143**	**1,888,897**	**486.7**	**281.6**	**56.8%**	**64.0%**
2035	**2,442,083**	**1,893,375**	**490.8**	**282.5**	**56.8%**	**64.0%**
2036	**2,460,336**	**1,898,249**	**494.2**	**283.5**	**56.7%**	**63.8%**
2037	**2,484,286**	**1,902,702**	**498.7**	**284.4**	**56.9%**	**64.0%**
2038	**2,505,191**	**1,907,552**	**502.6**	**285.4**	**56.9%**	**63.9%**
2039	**2,525,724**	**1,912,320**	**506.4**	**286.3**	**56.9%**	**63.9%**
2040	**2,542,976**	**1,917,144**	**509.6**	**287.3**	**56.8%**	**63.7%**
2041	**2,561,009**	**1,922,446**	**513.0**	**288.4**	**57.0%**	**63.9%**
2042	**2,578,209**	**1,927,690**	**516.2**	**289.4**	**57.0%**	**63.8%**
2043	**2,591,846**	**1,932,939**	**518.8**	**290.5**	**57.0%**	**63.8%**
2044	**2,603,815**	**1,938,625**	**521.1**	**291.6**	**56.9%**	**63.6%**
Average Annual Growth Rates						
Previous 10 Years	**-1.02%**	**5.32%**	**-2.34%**	**7.76%**	**1.32%**	**1.02%**
Previous 5 Years	**-0.73%**	**11.40%**	**-0.19%**	**17.32%**	**-0.60%**	**-0.79%**
Next 5 Years	**1.23%**	**2.84%**	**-0.73%**	**1.13%**	**2.03%**	**2.05%**
Next 10 Years	**1.05%**	**1.53%**	**0.01%**	**0.72%**	**1.07%**	**1.02%**
Next 20 Years	**0.89%**	**0.89%**	**0.35%**	**0.53%**	**0.54%**	**0.48%**

[1] Big Rivers has no current non-pilot Demand Side Management (DSM) or Energy Efficiency (EE) programs on the Rural system. A single Direct Serve consumer is engaged in DSM. Unless specified otherwise, the summary tables throughout this report assume the DSM for this consumer is active. Section 10 provides system totals with the DSM impact of this consumer added back into the forecast to create a forecast without DSM. Section 5 provides alternate forecasts with potential DSM impacts for additional programs.

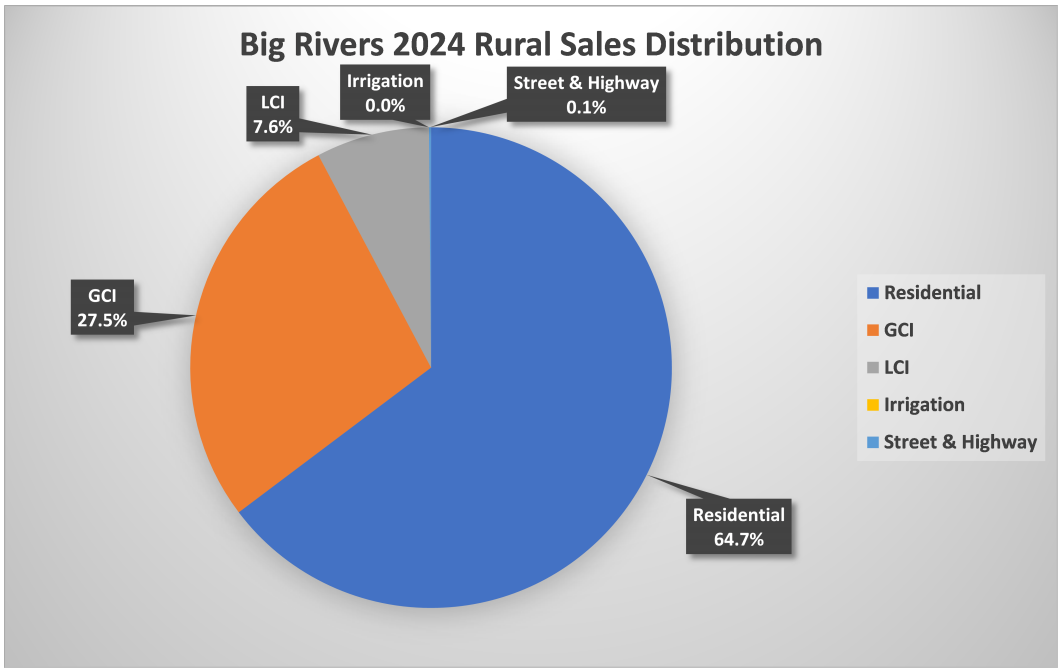
The following graph provides the Native system Rural energy requirements forecast.

Rural Energy Requirements



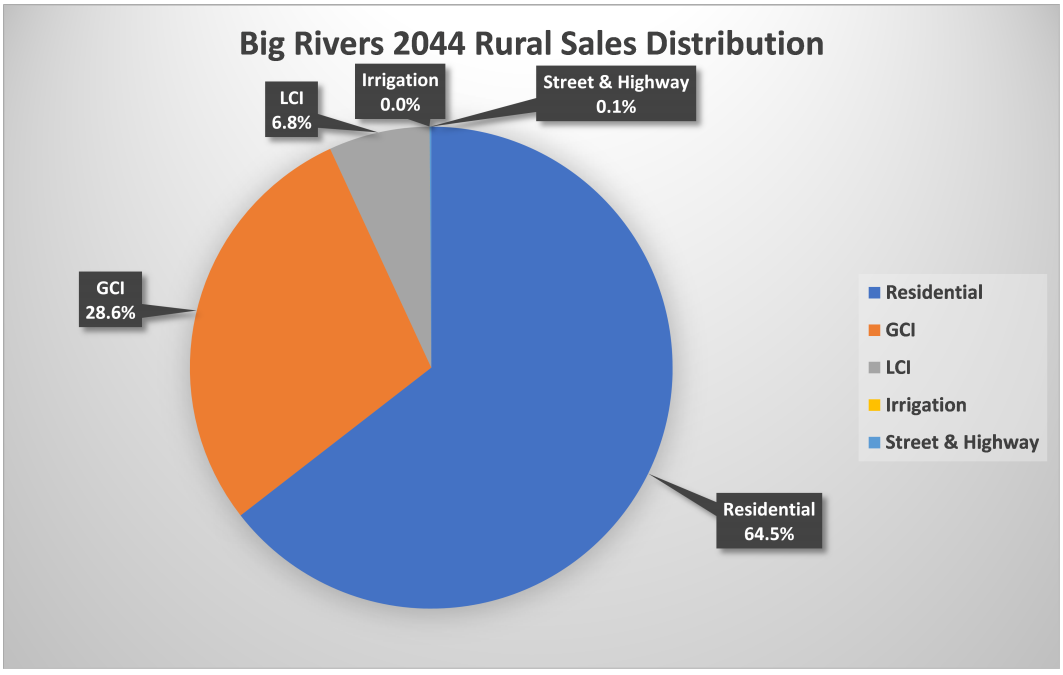
The figure below provides the Native system Rural sales distribution by class for 2024.

2024 Rural Sales by Class Distribution



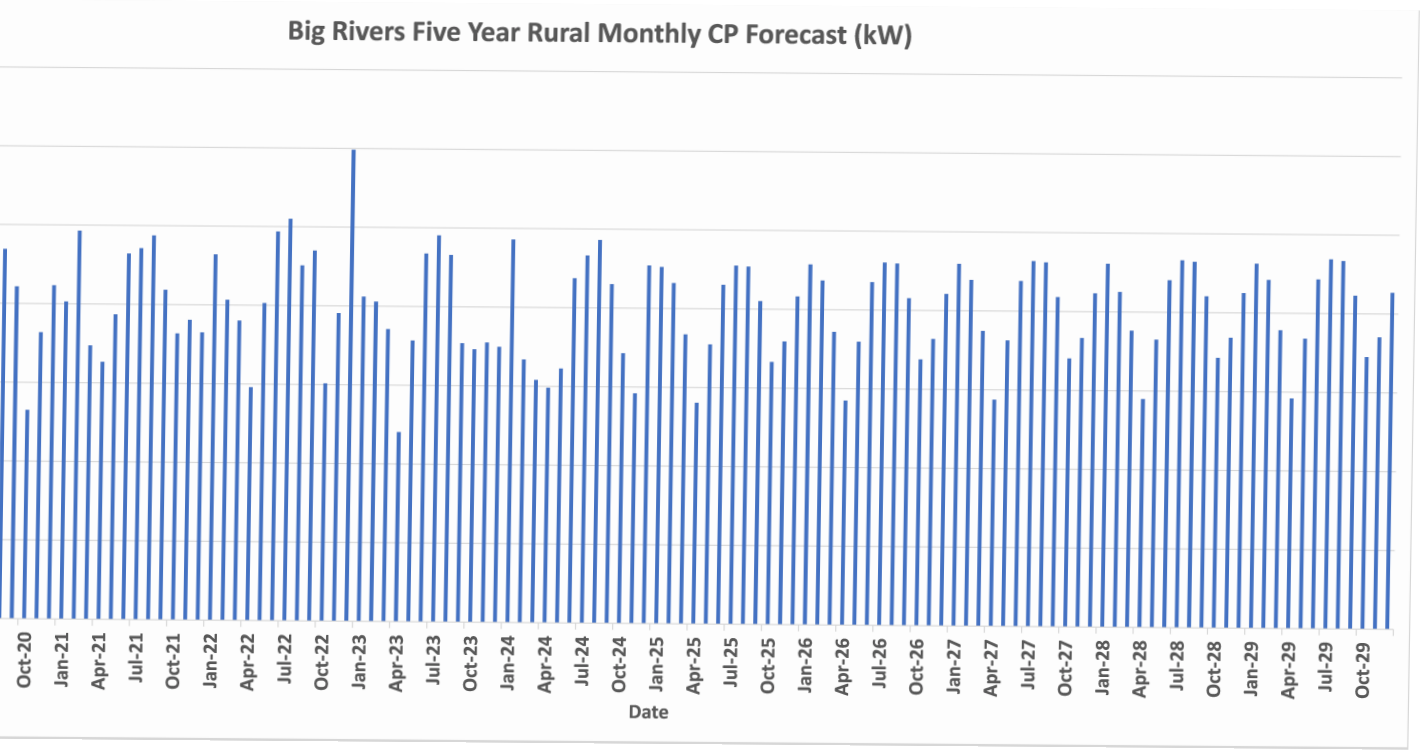
The figure below provides the Native system Rural sales distribution forecasted by class for 2044.

2044 Rural Sales by Class Distribution



in the following figure.

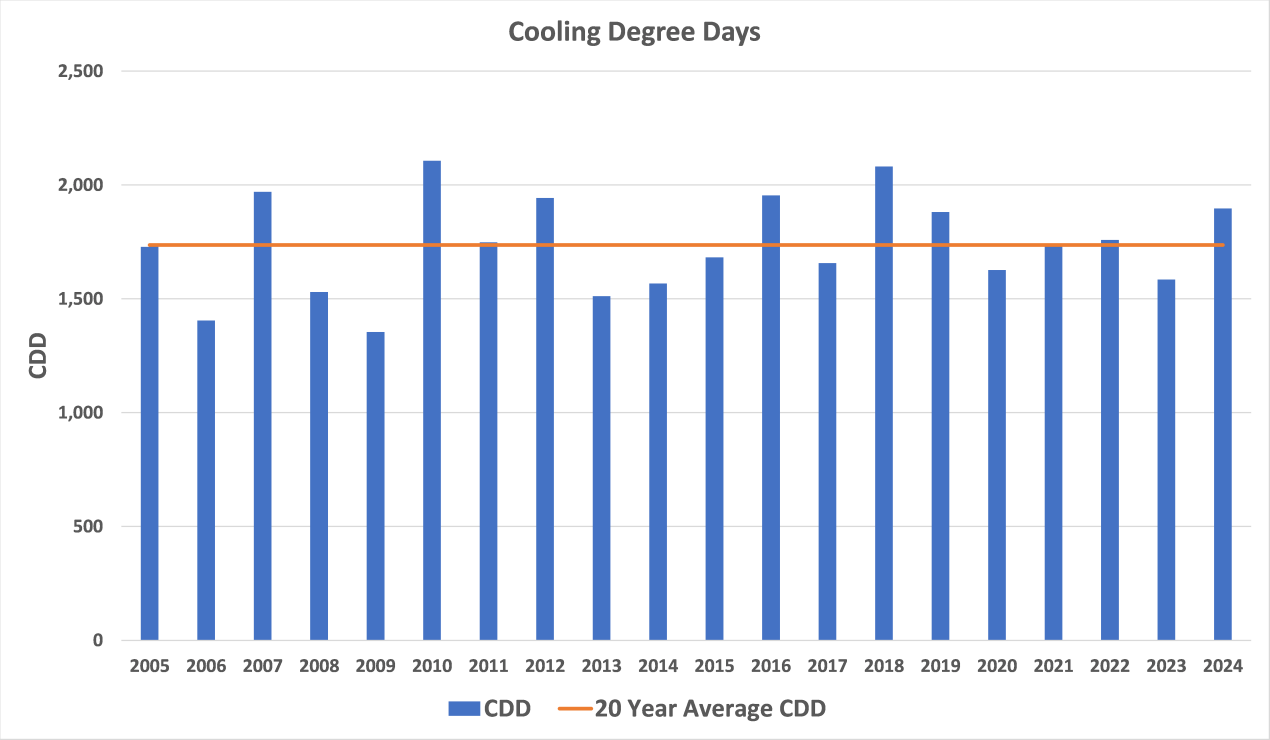
Monthly Rural Peak Forecast



1.4 2024 Weather Conditions

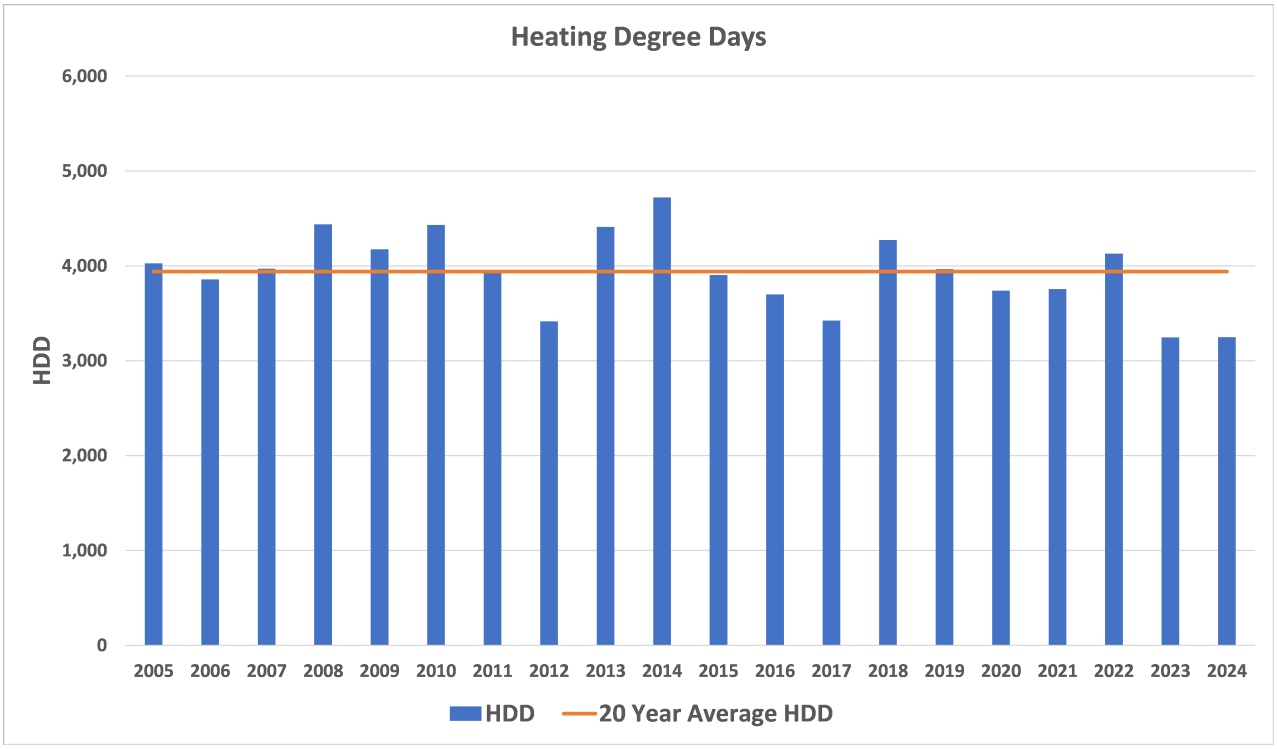
The forecast contains an assumption of a “normal” weather scenario for each class. Clearspring Energy compiled historical weather observations to enable the estimation of weather impacts on sales and peak loads. Weather variables such as cooling degree days (CDD), heating degree days (HDD), and peak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

Heating Degree Days for Last 20 Years



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.

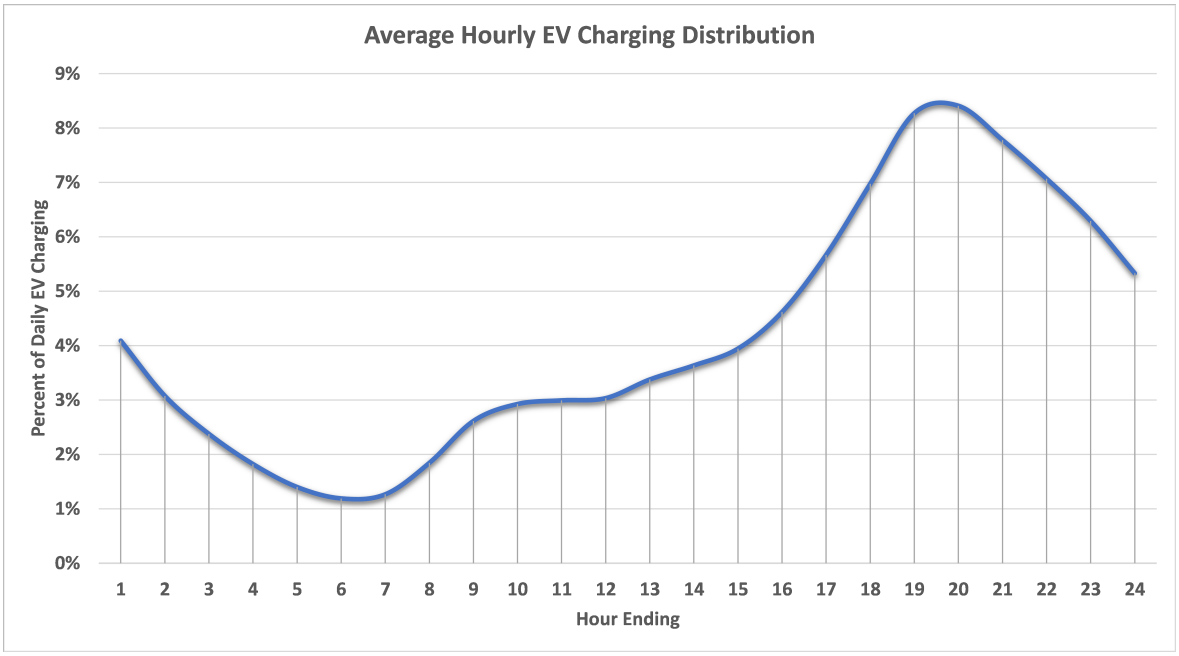
2 Electric Vehicle and Distributed Generation Forecast

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. 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 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

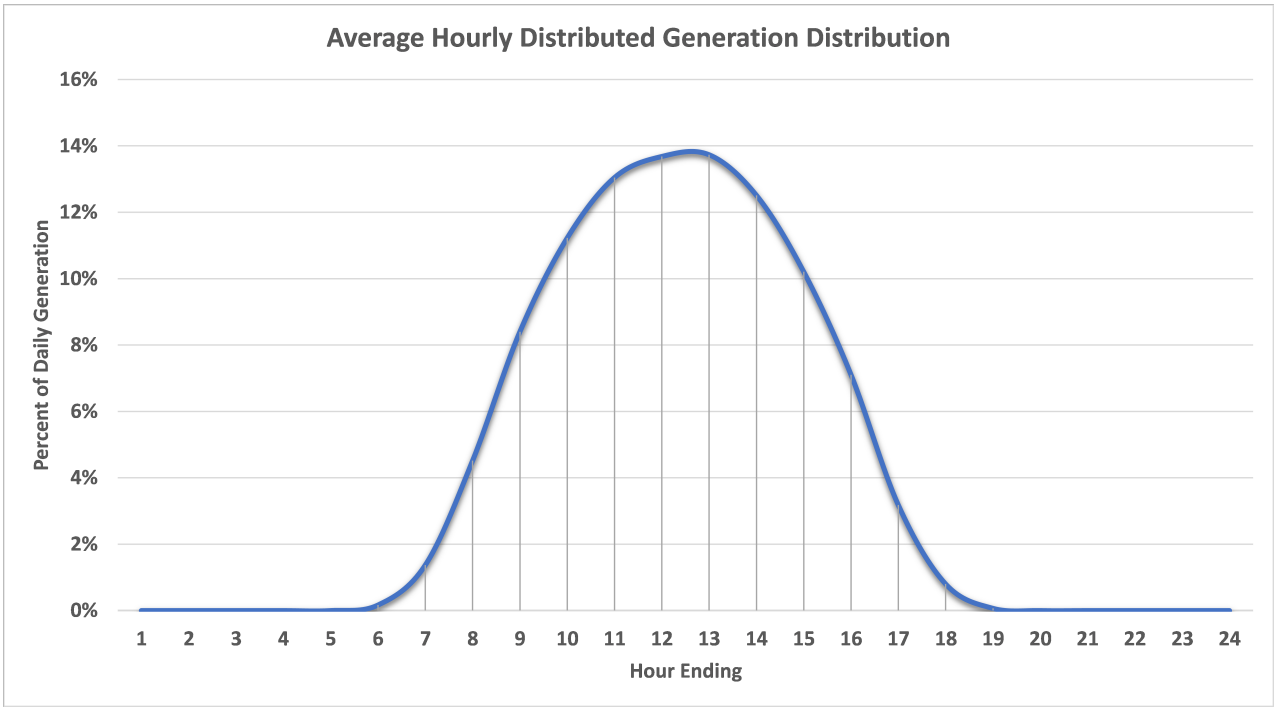
Big Rivers Rural System Electric Vehicle Forecast					
Year	Residential Energy (MWh)	Commercial Energy (MWh)	Distribution Losses (MWh)	Total Energy (MWh)	Rural Coincident Peak Contribution
2020	412	168	28	608	92
2021	639	261	40	940	65
2022	1,050	429	72	1,550	149
2023	1,501	613	88	2,203	334
2024	2,100	858	125	3,084	427
2025	**3,427**	**1,399**	**213**	**5,039**	**765**
2026	**5,788**	**2,364**	**360**	**8,511**	**1,292**
2027	**9,309**	**3,801**	**563**	**13,674**	**2,076**
2028	**13,871**	**5,664**	**839**	**20,374**	**3,093**
2029	**19,591**	**8,000**	**1,186**	**28,777**	**4,369**
2030	**26,614**	**10,867**	**1,611**	**39,092**	**5,935**
2031	**34,212**	**13,970**	**2,070**	**50,253**	**7,629**
2032	**43,049**	**17,579**	**2,605**	**63,233**	**9,600**
2033	**51,804**	**21,153**	**3,135**	**76,092**	**11,552**
2034	**60,733**	**24,800**	**3,675**	**89,208**	**13,543**
2035	**69,472**	**28,368**	**4,204**	**102,044**	**15,492**
2036	**78,017**	**31,857**	**4,722**	**114,596**	**17,397**
2037	**86,370**	**35,268**	**5,227**	**126,865**	**19,260**
2038	**94,373**	**38,536**	**5,711**	**138,621**	**21,044**
2039	**101,939**	**41,625**	**6,169**	**149,734**	**22,731**
2040	**109,005**	**44,511**	**6,597**	**160,113**	**24,307**
2041	**115,673**	**47,234**	**7,000**	**169,907**	**25,794**
2042	**121,774**	**49,725**	**7,370**	**178,869**	**27,155**
2043	**127,248**	**51,960**	**7,701**	**186,908**	**28,375**
2044	**132,052**	**53,922**	**7,992**	**193,966**	**29,447**
Average Annual Growth Rates					
Previous 10 Years	-	-	-	-	-
Previous 5 Years	**45.25%**	**45.25%**	**42.72%**	**45.14%**	**54.56%**
Next 5 Years	**56.30%**	**56.30%**	**56.71%**	**56.31%**	**59.20%**
Next 10 Years	**39.99%**	**39.99%**	**40.18%**	**40.00%**	**41.29%**
Next 20 Years	**23.00%**	**23.00%**	**23.09%**	**23.01%**	**23.57%**

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. 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 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
2020	-3,638	-2,590	-285	-6,513	-1,160
2021	-5,937	-4,226	-451	-10,613	-398
2022	-6,971	-4,962	-559	-12,492	-520
2023	-8,409	-5,985	-613	-15,008	-2,652
2024	-9,598	-6,832	-702	-17,133	-3,069
2025	**-11,010**	**-7,701**	**-826**	**-19,537**	**-3,453**
2026	**-12,446**	**-8,551**	**-927**	**-21,924**	**-3,874**
2027	**-13,777**	**-8,913**	**-984**	**-23,674**	**-4,184**
2028	**-14,298**	**-9,094**	**-1,014**	**-24,405**	**-4,311**
2029	**-14,825**	**-9,311**	**-1,045**	**-25,180**	**-4,445**
2030	**-15,383**	**-9,562**	**-1,079**	**-26,024**	**-4,591**
2031	**-15,977**	**-9,871**	**-1,117**	**-26,965**	**-4,754**
2032	**-16,567**	**-10,119**	**-1,152**	**-27,839**	**-4,906**
2033	**-17,175**	**-10,443**	**-1,191**	**-28,809**	**-5,074**
2034	**-17,776**	**-10,667**	**-1,225**	**-29,668**	**-5,223**
2035	**-18,271**	**-10,866**	**-1,254**	**-30,391**	**-5,348**
2036	**-18,778**	**-11,037**	**-1,283**	**-31,099**	**-5,471**
2037	**-19,294**	**-11,239**	**-1,313**	**-31,846**	**-5,601**
2038	**-19,819**	**-11,394**	**-1,342**	**-32,555**	**-5,724**
2039	**-20,353**	**-11,507**	**-1,369**	**-33,229**	**-5,841**
2040	**-20,895**	**-11,666**	**-1,399**	**-33,960**	**-5,968**
2041	**-21,443**	**-11,862**	**-1,430**	**-34,735**	**-6,103**
2042	**-22,006**	**-12,083**	**-1,463**	**-35,551**	**-6,244**
2043	**-22,574**	**-12,315**	**-1,497**	**-36,385**	**-6,389**
2044	**-23,153**	**-12,559**	**-1,531**	**-37,243**	**-6,538**
Average Annual Growth Rates					
Previous 10 Years	-	-	-	-	-
Previous 5 Years	**30.10%**	**30.10%**	**28.47%**	**30.03%**	**77.84%**
Next 5 Years	**9.08%**	**6.39%**	**8.27%**	**8.01%**	**7.69%**
Next 10 Years	**6.36%**	**4.56%**	**5.72%**	**5.64%**	**5.46%**
Next 20 Years	**4.50%**	**3.09%**	**3.97%**	**3.96%**	**3.85%**

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.

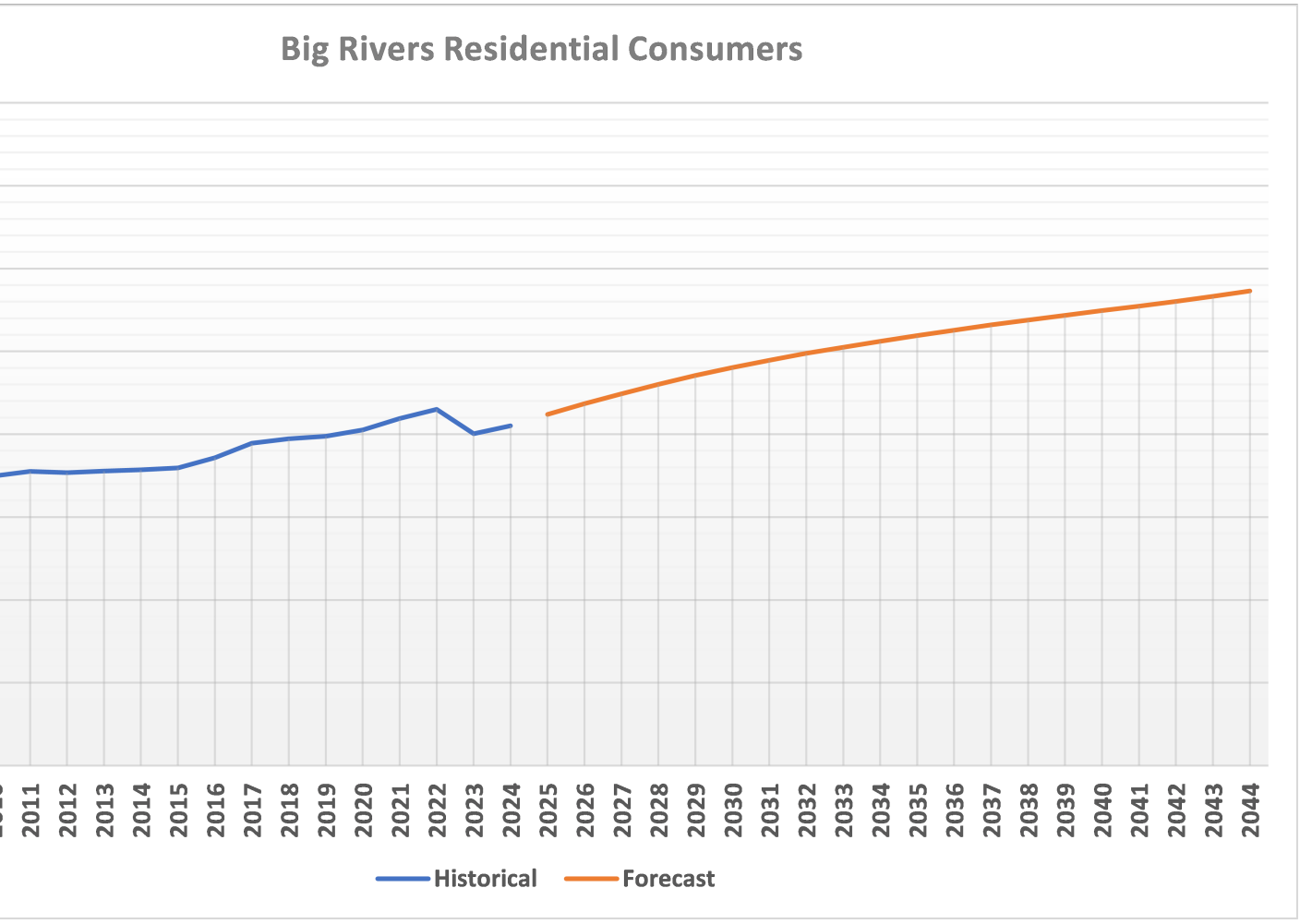
The following table provides the last five years of historical data and the next 20 years of forecasted data for the number of Residential customers, Residential use per consumer, and Residential energy sales. Growth rates for the prior 5 and 10 years and projected growth rates for the next 5, 10, and 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
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	100,036	-1.45%	12,878	-8.62%	1,288,283	-9.94%
2024	100,519	0.48%	13,438	4.35%	1,350,807	4.85%
2025	**101,190**	**0.67%**	**13,763**	**2.42%**	**1,392,722**	**3.10%**
2026	**101,840**	**0.64%**	**13,793**	**0.22%**	**1,404,711**	**0.86%**
2027	**102,447**	**0.60%**	**13,799**	**0.04%**	**1,413,702**	**0.64%**
2028	**103,017**	**0.56%**	**13,806**	**0.05%**	**1,422,226**	**0.60%**
2029	**103,543**	**0.51%**	**13,830**	**0.17%**	**1,431,945**	**0.68%**
2030	**104,029**	**0.47%**	**13,831**	**0.01%**	**1,438,795**	**0.48%**
2031	**104,472**	**0.43%**	**13,876**	**0.33%**	**1,449,666**	**0.76%**
2032	**104,880**	**0.39%**	**13,968**	**0.66%**	**1,464,987**	**1.06%**
2033	**105,257**	**0.36%**	**14,060**	**0.66%**	**1,479,925**	**1.02%**
2034	**105,617**	**0.34%**	**14,157**	**0.69%**	**1,495,172**	**1.03%**
2035	**105,961**	**0.33%**	**14,240**	**0.59%**	**1,508,848**	**0.91%**
2036	**106,289**	**0.31%**	**14,303**	**0.44%**	**1,520,241**	**0.76%**
2037	**106,601**	**0.29%**	**14,393**	**0.63%**	**1,534,344**	**0.93%**
2038	**106,899**	**0.28%**	**14,467**	**0.51%**	**1,546,517**	**0.79%**
2039	**107,186**	**0.27%**	**14,540**	**0.50%**	**1,558,494**	**0.77%**
2040	**107,464**	**0.26%**	**14,599**	**0.40%**	**1,568,848**	**0.66%**
2041	**107,740**	**0.26%**	**14,663**	**0.44%**	**1,579,824**	**0.70%**
2042	**108,025**	**0.26%**	**14,724**	**0.41%**	**1,590,539**	**0.68%**
2043	**108,326**	**0.28%**	**14,766**	**0.29%**	**1,599,590**	**0.57%**
2044	**108,641**	**0.29%**	**14,797**	**0.21%**	**1,607,585**	**0.50%**
Average Annual Growth Rates						
Previous 10 Years	**0.27%**		**-1.51%**		**-1.25%**	
Previous 5 Years	**0.13%**		**-0.99%**		**-0.87%**	
Next 5 Years	**0.59%**		**0.58%**		**1.17%**	
Next 10 Years	**0.50%**		**0.52%**		**1.02%**	
Next 20 Years	**0.39%**		**0.48%**		**0.87%**	

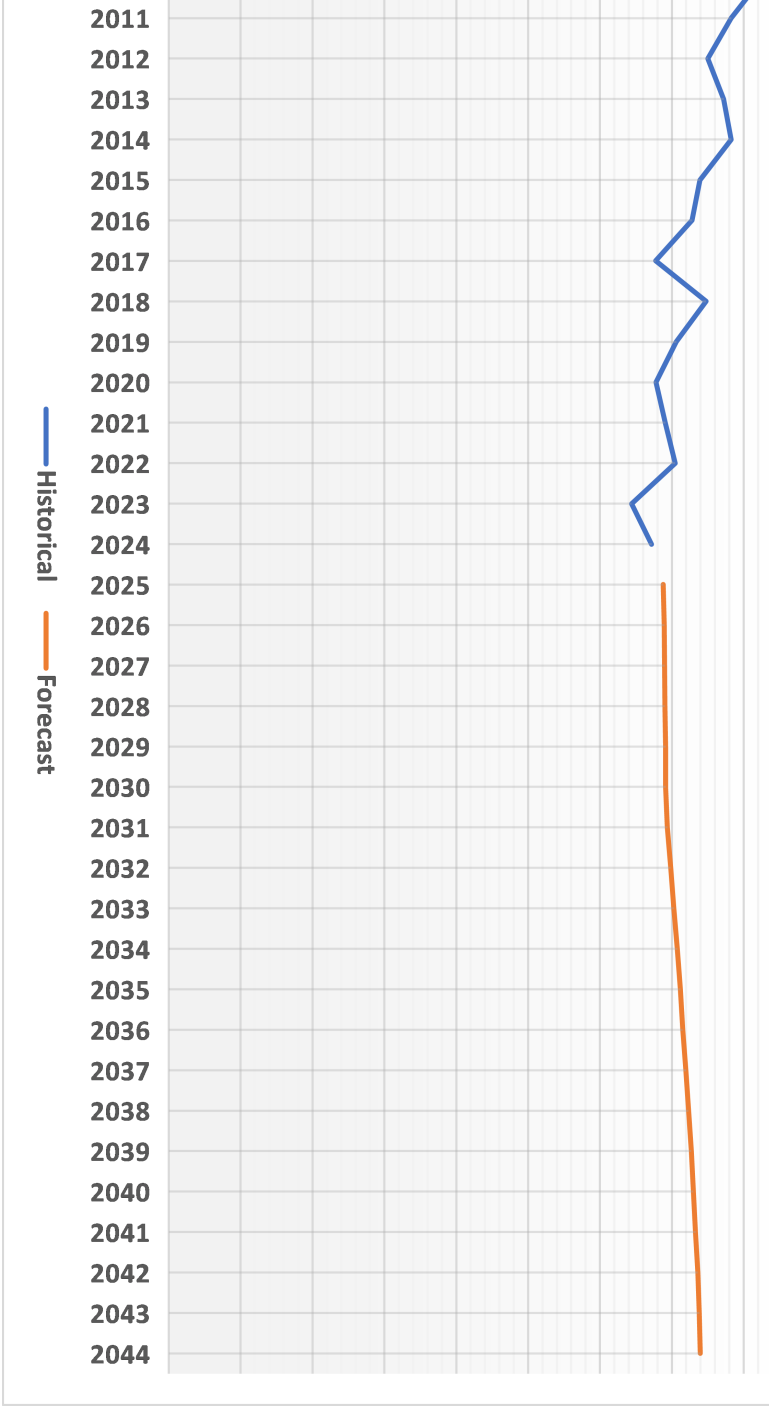
e household growth estimates are used to project the number of Residential members s with additional adjustments made based on cooperative staff recommendations. figure provides the historical and projected Residential consumers on the Big Rivers dential consumers are projected to increase over the next five years at an average f 0.59%. After the first five years of the forecast, the housing growth is expected to er years of the forecast. Recent years have shown lower consumer growth due to a n of consumers to the commercial class in 2023.

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 216 observations from January 2007 to December 2024. 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 rise through the first five years of the forecast at an average annual rate of 0.58%. This includes an increase in the first forecast year relative to the prior two years due to mild winter HDD conditions over the past two years. 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.


2011
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2044
Historical
Forecast

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.

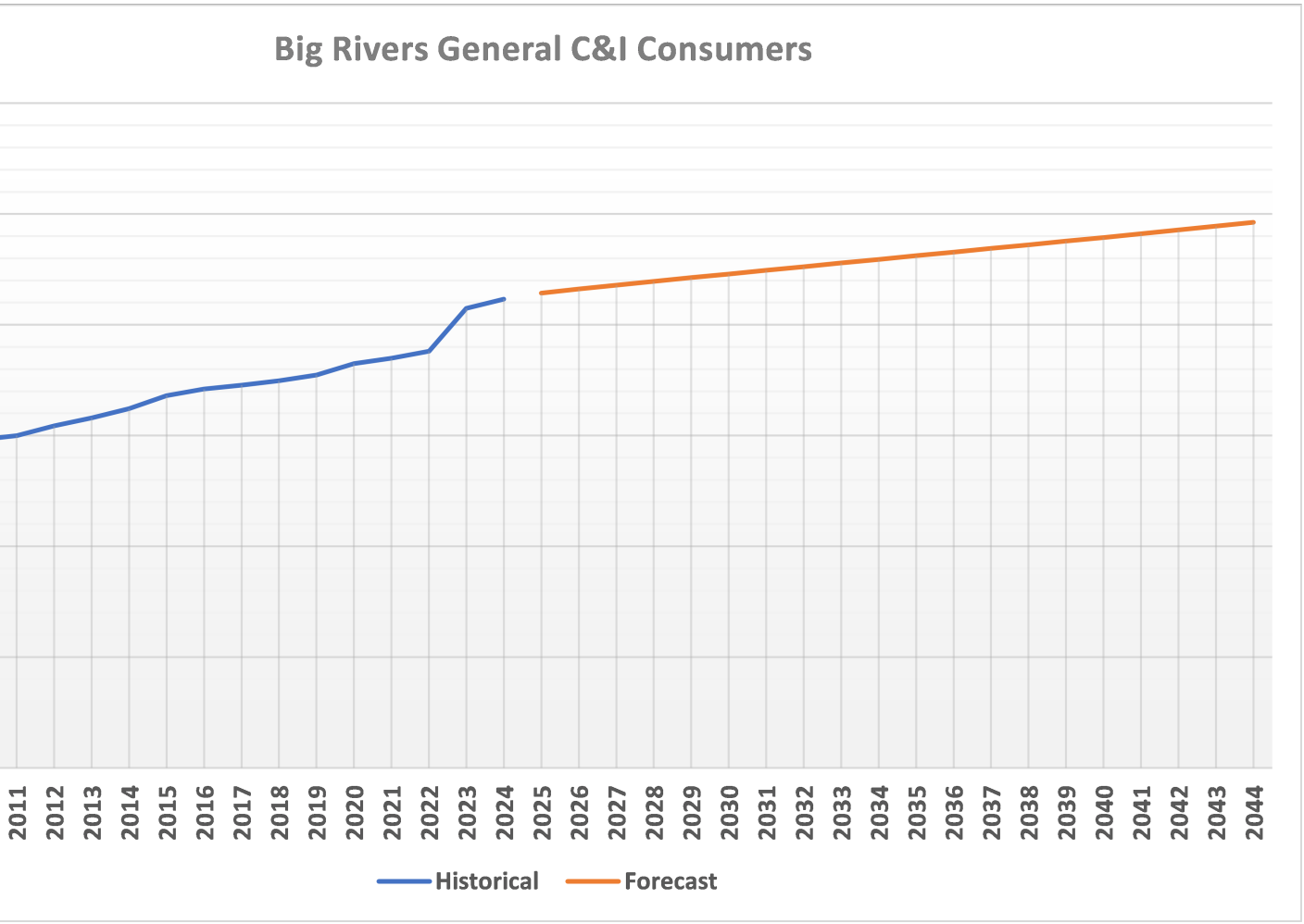
The following table provides the last five years of historical data and the next 20 years of forecasted data for the number of GCI customers, GCI use per consumer, and GCI energy sales. Growth rates for the prior 5 and 10 years and projected growth rates for the next 5, 10, and 20 years are provided 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
2020	18,249	2.89%	29,181	-9.49%	532,524	-6.87%
2021	18,489	1.31%	30,146	3.31%	557,358	4.66%
2022	18,801	1.69%	29,936	-0.69%	562,848	0.98%
2023	20,736	10.29%	26,810	-10.44%	555,946	-1.23%
2024	21,160	2.04%	27,162	1.31%	574,743	3.38%
2025	21,427	1.26%	27,338	0.65%	585,752	1.92%
2026	21,611	0.86%	27,586	0.91%	596,143	1.77%
2027	21,789	0.83%	27,875	1.05%	607,363	1.88%
2028	21,958	0.77%	27,941	0.24%	613,529	1.02%
2029	22,126	0.77%	27,986	0.16%	619,214	0.93%
2030	22,292	0.75%	27,934	-0.19%	622,721	0.57%
2031	22,458	0.74%	28,048	0.41%	629,899	1.15%
2032	22,622	0.73%	28,206	0.56%	638,083	1.30%
2033	22,786	0.73%	28,303	0.34%	644,916	1.07%
2034	22,951	0.72%	28,440	0.48%	652,709	1.21%
2035	23,115	0.72%	28,543	0.36%	659,787	1.08%
2036	23,280	0.71%	28,591	0.17%	665,607	0.88%
2037	23,446	0.71%	28,753	0.57%	674,142	1.28%
2038	23,612	0.71%	28,871	0.41%	681,690	1.12%
2039	23,777	0.70%	28,982	0.38%	689,111	1.09%
2040	23,944	0.70%	29,026	0.15%	695,002	0.85%
2041	24,112	0.70%	29,073	0.16%	701,002	0.86%
2042	24,281	0.70%	29,096	0.08%	706,484	0.78%
2043	24,452	0.70%	29,045	-0.18%	710,218	0.53%
2044	24,625	0.71%	28,972	-0.25%	713,436	0.45%
Average Annual Growth Rates						
Previous 10 Years	2.70%		-3.20%		-0.59%	
Previous 5 Years	3.59%		-3.37%		0.10%	
Next 5 Years	0.90%		0.60%		1.50%	
Next 10 Years	0.82%		0.46%		1.28%	
Next 20 Years	0.76%		0.32%		1.09%	

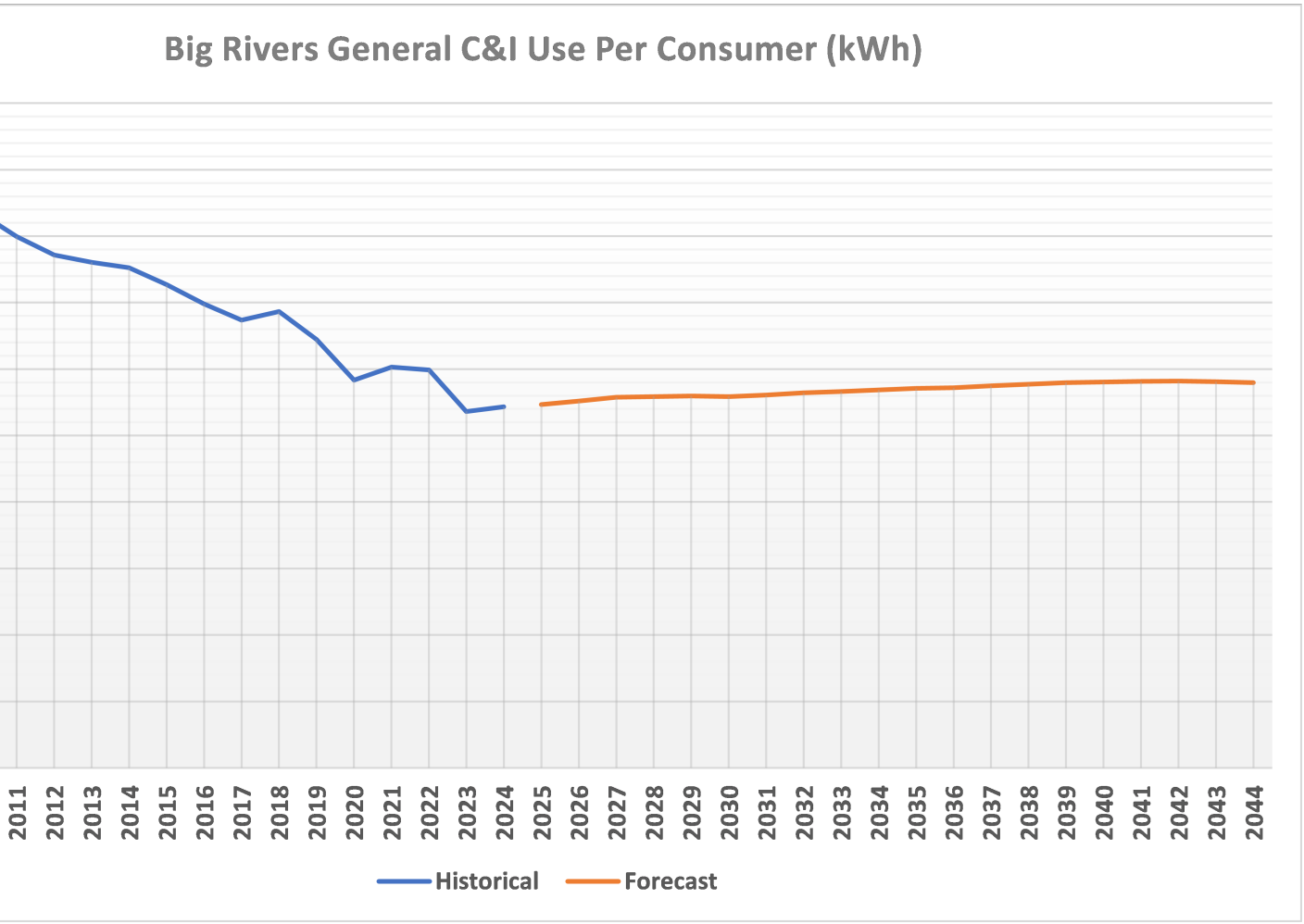
each distribution cooperatives 2024 GCI consumer values. Explanatory variable ojected in future years using economic projections. Preliminary model results were cooperative staff and modifications were made if necessary where staff had specific the service territory and conditions. The GCI consumer models are provided in the he following figure provides the historical and projected GCI consumers for the Big system. GCI consumers experienced a large increase in 2023 as many accounts ied into GCI from the residential class.

GCI Consumers



within the counties served. Explanatory variable values are projected in future years aphic and economic projections and weather normalized values. Preliminary model eviewed by cooperative staff and modifications were made if necessary where staff nowledge of the service territory and conditions. The GCI use per consumer models n the Appendix. The following figure provides the historical and projected GCI use 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 2024 the Big Rivers LCI class contained 42 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
2020	44	-1.51%	3,808	-2.41%	165,984	-3.88%
2021	43	-1.34%	3,836	0.73%	164,961	-0.62%
2022	42	-1.36%	3,849	0.32%	163,242	-1.04%
2023	43	0.79%	3,773	-1.96%	161,296	-1.19%
2024	42	-1.75%	3,777	0.10%	158,629	-1.65%
2025	**41**	**-2.38%**	**3,839**	**1.65%**	**157,403**	**-0.77%**
2026	**42**	**2.44%**	**3,882**	**1.12%**	**163,044**	**3.58%**
2027	**42**	**0.00%**	**3,892**	**0.25%**	**163,449**	**0.25%**
2028	**42**	**0.00%**	**3,896**	**0.12%**	**163,652**	**0.12%**
2029	**42**	**0.00%**	**3,905**	**0.21%**	**163,999**	**0.21%**
2030	**42**	**0.00%**	**3,913**	**0.22%**	**164,352**	**0.22%**
2031	**42**	**0.00%**	**3,922**	**0.23%**	**164,727**	**0.23%**
2032	**42**	**0.00%**	**3,930**	**0.20%**	**165,064**	**0.20%**
2033	**42**	**0.00%**	**3,937**	**0.18%**	**165,355**	**0.18%**
2034	**42**	**0.00%**	**3,944**	**0.18%**	**165,652**	**0.18%**
2035	**42**	**0.00%**	**3,951**	**0.17%**	**165,926**	**0.17%**
2036	**42**	**0.00%**	**3,957**	**0.17%**	**166,206**	**0.17%**
2037	**42**	**0.00%**	**3,965**	**0.19%**	**166,526**	**0.19%**
2038	**42**	**0.00%**	**3,972**	**0.19%**	**166,845**	**0.19%**
2039	**42**	**0.00%**	**3,979**	**0.17%**	**167,129**	**0.17%**
2040	**42**	**0.00%**	**3,986**	**0.17%**	**167,420**	**0.17%**
2041	**42**	**0.00%**	**3,994**	**0.18%**	**167,730**	**0.18%**
2042	**42**	**0.00%**	**4,000**	**0.17%**	**168,020**	**0.17%**
2043	**42**	**0.00%**	**4,007**	**0.17%**	**168,304**	**0.17%**
2044	**42**	**0.00%**	**4,013**	**0.15%**	**168,560**	**0.15%**
Average Annual Growth Rates						
Previous 10 Years	**3.06%**		**-2.74%**		**0.23%**	
Previous 5 Years	**-1.04%**		**-0.65%**		**-1.68%**	
Next 5 Years	**0.00%**		**0.67%**		**0.67%**	
Next 10 Years	**0.00%**		**0.43%**		**0.43%**	
Next 20 Years	**0.00%**		**0.30%**		**0.30%**	

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 2024. The Direct Serve class is expected to add one additional consumer in 2026, and one in 2027.

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 2024 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
2020	19	-6.25%	43,984	-7.02%	824,695	-12.83%
2021	16	-16.44%	49,887	13.42%	781,559	-5.23%
2022	16	4.79%	49,436	-0.90%	811,577	3.84%
2023	16	-2.03%	72,565	46.78%	1,167,083	43.80%
2024	16	1.55%	99,380	36.95%	1,623,201	39.08%
2025	**16**	**-1.02%**	**110,416**	**11.11%**	**1,785,062**	**9.97%**
2026	**17**	**5.15%**	**108,398**	**-1.83%**	**1,842,767**	**3.23%**
2027	**18**	**5.88%**	**103,391**	**-4.62%**	**1,861,031**	**0.99%**
2028	**18**	**0.00%**	**103,504**	**0.11%**	**1,863,066**	**0.11%**
2029	**18**	**0.00%**	**103,727**	**0.22%**	**1,867,091**	**0.22%**
2030	**18**	**0.00%**	**103,975**	**0.24%**	**1,871,556**	**0.24%**
2031	**18**	**0.00%**	**104,232**	**0.25%**	**1,876,179**	**0.25%**
2032	**18**	**0.00%**	**104,458**	**0.22%**	**1,880,236**	**0.22%**
2033	**18**	**0.00%**	**104,714**	**0.25%**	**1,884,854**	**0.25%**
2034	**18**	**0.00%**	**104,939**	**0.21%**	**1,888,897**	**0.21%**
2035	**18**	**0.00%**	**105,187**	**0.24%**	**1,893,375**	**0.24%**
2036	**18**	**0.00%**	**105,458**	**0.26%**	**1,898,249**	**0.26%**
2037	**18**	**0.00%**	**105,706**	**0.23%**	**1,902,702**	**0.23%**
2038	**18**	**0.00%**	**105,975**	**0.25%**	**1,907,552**	**0.25%**
2039	**18**	**0.00%**	**106,240**	**0.25%**	**1,912,320**	**0.25%**
2040	**18**	**0.00%**	**106,508**	**0.25%**	**1,917,144**	**0.25%**
2041	**18**	**0.00%**	**106,803**	**0.28%**	**1,922,446**	**0.28%**
2042	**18**	**0.00%**	**107,094**	**0.27%**	**1,927,690**	**0.27%**
2043	**18**	**0.00%**	**107,385**	**0.27%**	**1,932,939**	**0.27%**
2044	**18**	**0.00%**	**107,701**	**0.29%**	**1,938,625**	**0.29%**
Average Annual Growth Rates						
Previous 10 Years	**-2.00%**		**7.48%**		**5.32%**	
Previous 5 Years	**-3.97%**		**16.01%**		**11.40%**	
Next 5 Years	**1.96%**		**0.86%**		**2.84%**	
Next 10 Years	**0.98%**		**0.55%**		**1.53%**	
Next 20 Years	**0.49%**		**0.40%**		**0.89%**	

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 a small decline was forecasted for use per consumer through 2030 to account for ongoing LED conversions.

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
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%	24,234	-4.33%	3,011	-0.04%
2023	143	14.89%	21,100	-12.93%	3,012	0.03%
2024	150	5.08%	19,764	-6.33%	2,965	-1.58%
2025	**150**	**0.00%**	**19,716**	**-0.24%**	**2,957**	**-0.24%**
2026	**150**	**0.00%**	**19,635**	**-0.41%**	**2,945**	**-0.41%**
2027	**150**	**0.00%**	**19,555**	**-0.41%**	**2,933**	**-0.41%**
2028	**150**	**0.00%**	**19,475**	**-0.41%**	**2,921**	**-0.41%**
2029	**150**	**0.00%**	**19,397**	**-0.40%**	**2,910**	**-0.40%**
2030	**150**	**0.00%**	**19,361**	**-0.18%**	**2,904**	**-0.18%**
2031	**150**	**0.00%**	**19,361**	**0.00%**	**2,904**	**0.00%**
2032	**150**	**0.00%**	**19,361**	**0.00%**	**2,904**	**0.00%**
2033	**150**	**0.00%**	**19,361**	**0.00%**	**2,904**	**0.00%**
2034	**150**	**0.00%**	**19,361**	**0.00%**	**2,904**	**0.00%**
2035	**150**	**0.00%**	**19,361**	**0.00%**	**2,904**	**0.00%**
2036	**150**	**0.00%**	**19,361**	**0.00%**	**2,904**	**0.00%**
2037	**150**	**0.00%**	**19,361**	**0.00%**	**2,904**	**0.00%**
2038	**150**	**0.00%**	**19,361**	**0.00%**	**2,904**	**0.00%**
2039	**150**	**0.00%**	**19,361**	**0.00%**	**2,904**	**0.00%**
2040	**150**	**0.00%**	**19,361**	**0.00%**	**2,904**	**0.00%**
2041	**150**	**0.00%**	**19,361**	**0.00%**	**2,904**	**0.00%**
2042	**150**	**0.00%**	**19,361**	**0.00%**	**2,904**	**0.00%**
2043	**150**	**0.00%**	**19,361**	**0.00%**	**2,904**	**0.00%**
2044	**150**	**0.00%**	**19,361**	**0.00%**	**2,904**	**0.00%**
Average Annual Growth Rates						
Previous 10 Years	**5.12%**		**-6.34%**		**-1.54%**	
Previous 5 Years	**7.12%**		**-7.15%**		**-0.54%**	
Next 5 Years	**0.00%**		**-0.37%**		**-0.37%**	
Next 10 Years	**0.00%**		**-0.21%**		**-0.21%**	
Next 20 Years	**0.00%**		**-0.10%**		**-0.10%**	

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 four 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
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%	17,654	-32.31%	88	-32.31%
2024	5	0.00%	8,272	-53.15%	41	-53.15%
2025	**5**	**0.00%**	**17,178**	**107.68%**	**86**	**107.68%**
2026	**5**	**0.00%**	**17,178**	**0.00%**	**86**	**0.00%**
2027	**5**	**0.00%**	**17,178**	**0.00%**	**86**	**0.00%**
2028	**5**	**0.00%**	**17,178**	**0.00%**	**86**	**0.00%**
2029	**5**	**0.00%**	**17,178**	**0.00%**	**86**	**0.00%**
2030	**5**	**0.00%**	**17,178**	**0.00%**	**86**	**0.00%**
2031	**5**	**0.00%**	**17,178**	**0.00%**	**86**	**0.00%**
2032	**5**	**0.00%**	**17,178**	**0.00%**	**86**	**0.00%**
2033	**5**	**0.00%**	**17,178**	**0.00%**	**86**	**0.00%**
2034	**5**	**0.00%**	**17,178**	**0.00%**	**86**	**0.00%**
2035	**5**	**0.00%**	**17,178**	**0.00%**	**86**	**0.00%**
2036	**5**	**0.00%**	**17,178**	**0.00%**	**86**	**0.00%**
2037	**5**	**0.00%**	**17,178**	**0.00%**	**86**	**0.00%**
2038	**5**	**0.00%**	**17,178**	**0.00%**	**86**	**0.00%**
2039	**5**	**0.00%**	**17,178**	**0.00%**	**86**	**0.00%**
2040	**5**	**0.00%**	**17,178**	**0.00%**	**86**	**0.00%**
2041	**5**	**0.00%**	**17,178**	**0.00%**	**86**	**0.00%**
2042	**5**	**0.00%**	**17,178**	**0.00%**	**86**	**0.00%**
2043	**5**	**0.00%**	**17,178**	**0.00%**	**86**	**0.00%**
2044	**5**	**0.00%**	**17,178**	**0.00%**	**86**	**0.00%**
Average Annual Growth Rates						
Previous 10 Years	**2.26%**		**-13.21%**		**-11.25%**	
Previous 5 Years	**0.00%**		**-18.31%**		**-18.31%**	
Next 5 Years	**0.00%**		**15.74%**		**15.74%**	
Next 10 Years	**0.00%**		**7.58%**		**7.58%**	
Next 20 Years	**0.00%**		**3.72%**		**3.72%**	

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 with an adjustment made at one of the distribution Members beginning in 2027 through the forecast due to anticipated improvements from new equipment. 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 (2020 to 2024) 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
2020	1,359,904	532,524	165,984	50	3,050	100,542	2,814	2,164,868
2021	1,395,391	557,358	164,961	84	3,012	94,909	3,666	2,219,380
2022	1,430,495	562,848	163,242	130	3,011	105,756	4,103	2,269,586
2023	1,288,283	555,946	161,296	88	3,012	85,141	3,893	2,097,660
2024	1,350,807	574,743	158,629	41	2,965	88,764	3,836	2,179,785
2025	**1,392,722**	**585,752**	**157,403**	**86**	**2,957**	**95,343**	**3,997**	**2,238,259**
2026	**1,404,711**	**596,143**	**163,044**	**86**	**2,945**	**96,577**	**4,023**	**2,267,529**
2027	**1,413,702**	**607,363**	**163,449**	**86**	**2,933**	**93,924**	**4,047**	**2,285,503**
2028	**1,422,226**	**613,529**	**163,652**	**86**	**2,921**	**94,562**	**4,069**	**2,301,046**
2029	**1,431,945**	**619,214**	**163,999**	**86**	**2,910**	**95,238**	**4,090**	**2,317,481**
2030	**1,438,795**	**622,721**	**164,352**	**86**	**2,904**	**95,700**	**4,109**	**2,328,667**
2031	**1,449,666**	**629,899**	**164,727**	**86**	**2,904**	**96,489**	**4,126**	**2,347,896**
2032	**1,464,987**	**638,083**	**165,064**	**86**	**2,904**	**97,508**	**4,142**	**2,372,775**
2033	**1,479,925**	**644,916**	**165,355**	**86**	**2,904**	**98,452**	**4,157**	**2,395,795**
2034	**1,495,172**	**652,709**	**165,652**	**86**	**2,904**	**99,449**	**4,171**	**2,420,143**
2035	**1,508,848**	**659,787**	**165,926**	**86**	**2,904**	**100,347**	**4,184**	**2,442,083**
2036	**1,520,241**	**665,607**	**166,206**	**86**	**2,904**	**101,095**	**4,197**	**2,460,336**
2037	**1,534,344**	**674,142**	**166,526**	**86**	**2,904**	**102,075**	**4,209**	**2,484,286**
2038	**1,546,517**	**681,690**	**166,845**	**86**	**2,904**	**102,929**	**4,221**	**2,505,191**
2039	**1,558,494**	**689,111**	**167,129**	**86**	**2,904**	**103,768**	**4,232**	**2,525,724**
2040	**1,568,848**	**695,002**	**167,420**	**86**	**2,904**	**104,473**	**4,242**	**2,542,976**
2041	**1,579,824**	**701,002**	**167,730**	**86**	**2,904**	**105,209**	**4,253**	**2,561,009**
2042	**1,590,539**	**706,484**	**168,020**	**86**	**2,904**	**105,912**	**4,264**	**2,578,209**
2043	**1,599,590**	**710,218**	**168,304**	**86**	**2,904**	**106,469**	**4,275**	**2,591,846**
2044	**1,607,585**	**713,436**	**168,560**	**86**	**2,904**	**106,957**	**4,287**	**2,603,815**
Average Annual Growth Rates								
Previous 10 Years	**-1.25%**	**-0.59%**	**0.23%**	**-11.25%**	**-1.54%**	**-2.50%**	**13.46%**	**-1.02%**
Previous 5 Years	**-0.87%**	**0.10%**	**-1.68%**	**-18.31%**	**-0.54%**	**-2.27%**	**4.44%**	**-0.73%**
Next 5 Years	**1.17%**	**1.50%**	**0.67%**	**15.74%**	**-0.37%**	**1.42%**	**1.29%**	**1.23%**
Next 10 Years	**1.02%**	**1.28%**	**0.43%**	**7.58%**	**-0.21%**	**1.14%**	**0.84%**	**1.05%**
Next 20 Years	**0.87%**	**1.09%**	**0.30%**	**3.72%**	**-0.10%**	**0.94%**	**0.56%**	**0.89%**

3.6 TOTAL NATIVE SYSTEM ENERGY

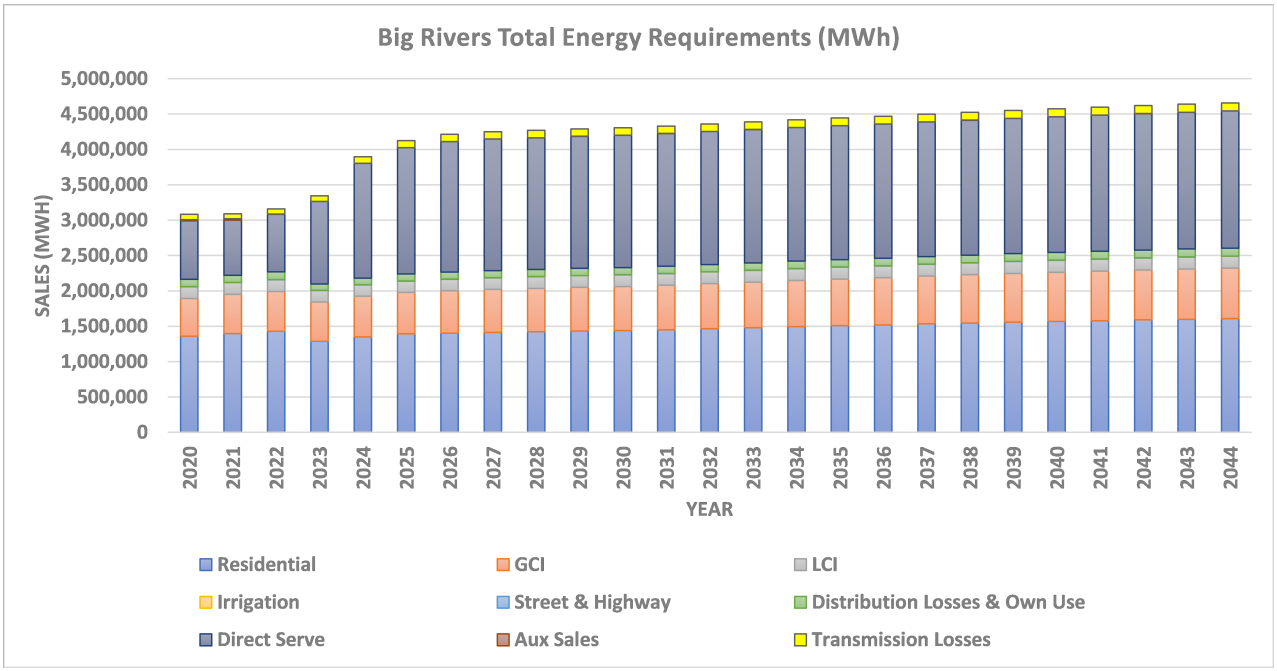
The total system Native energy requirements consists of the Rural system requirements, Direct Serve energy, auxiliary load for certain retired units which has diminished to an immaterial amount, and transmission losses. Transmission losses are forecasted at 2.44% for the full forecast. The table below 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
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	811,577	6,184	72,325	3,159,672
2023	2,097,660	1,167,083	833	78,103	3,343,678
2024	2,179,785	1,623,201	935	93,173	3,897,094
2025	2,238,259	1,785,062	935	100,594	4,124,850
2026	2,267,529	1,842,767	935	102,768	4,213,999
2027	2,285,503	1,861,031	935	103,674	4,251,143
2028	2,301,046	1,863,066	935	104,114	4,269,159
2029	2,317,481	1,867,091	935	104,625	4,290,131
2030	2,328,667	1,871,556	935	105,016	4,306,175
2031	2,347,896	1,876,179	935	105,613	4,330,623
2032	2,372,775	1,880,236	935	106,336	4,360,282
2033	2,395,795	1,884,854	935	107,027	4,388,610
2034	2,420,143	1,888,897	935	107,736	4,417,711
2035	2,442,083	1,893,375	935	108,397	4,444,789
2036	2,460,336	1,898,249	935	108,975	4,468,495
2037	2,484,286	1,902,702	935	109,685	4,497,607
2038	2,505,191	1,907,552	935	110,329	4,524,006
2039	2,525,724	1,912,320	935	110,961	4,549,940
2040	2,542,976	1,917,144	935	111,513	4,572,567
2041	2,561,009	1,922,446	935	112,096	4,596,485
2042	2,578,209	1,927,690	935	112,657	4,619,491
2043	2,591,846	1,932,939	935	113,129	4,638,848
2044	2,603,815	1,938,625	935	113,571	4,656,945
Average Annual Growth Rates					
Previous 10 Years	-1.02%	5.32%	-	5.52%	1.27%
Previous 5 Years	-0.73%	11.40%	-26.76%	2.38%	3.42%
Next 5 Years	1.23%	2.84%	0.00%	2.35%	1.94%
Next 10 Years	1.05%	1.53%	0.00%	1.46%	1.26%
Next 20 Years	0.89%	0.89%	0.00%	0.99%	0.89%

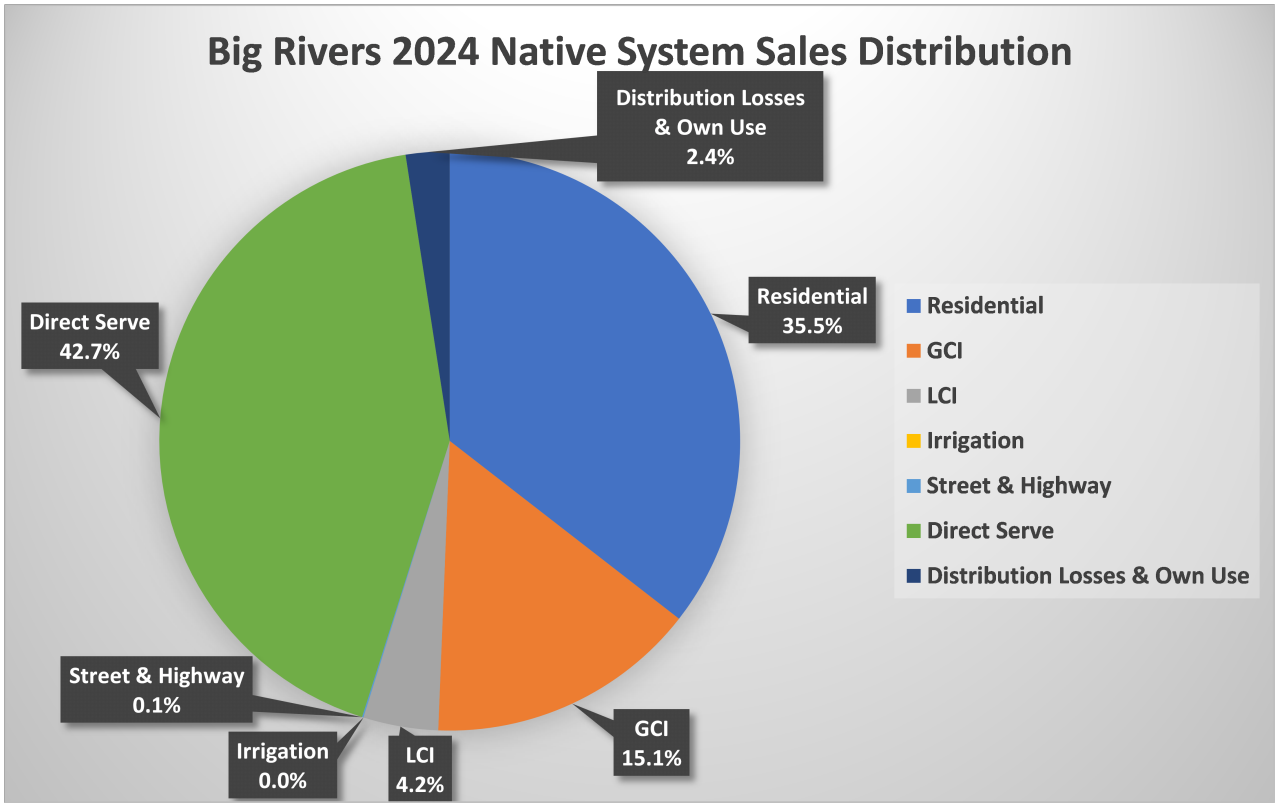
The following graph provides the class components that comprise the total energy requirements for the Big Rivers Native system.

Total Native Energy Forecast



The figure below provides the Native sales[3] distribution by each contributing component for 2024.

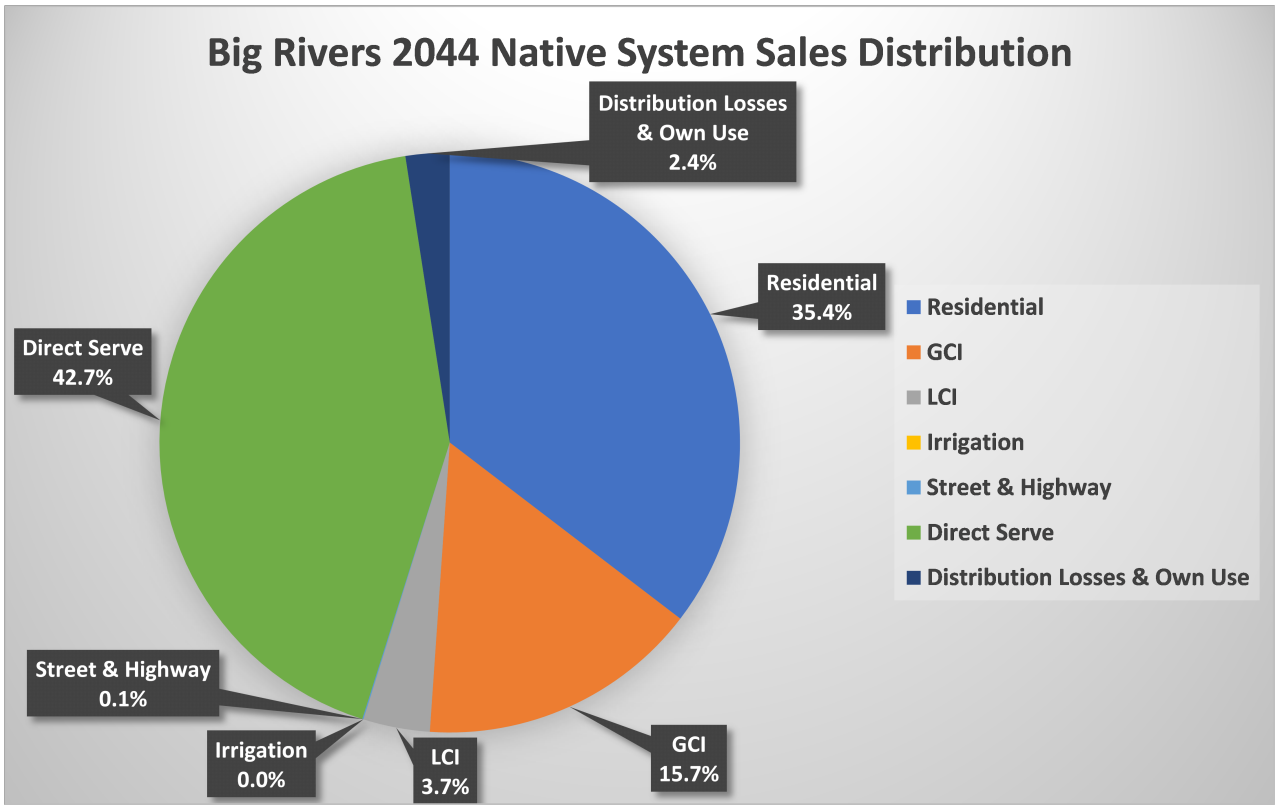
2024 Native System Sales by Class Distribution



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

The figure below provides the Native sales distribution by each contributing component for 2044. The largest change in the class distribution is within the GCI class. The Direct Serve class contributed 15.1% of sales in 2024 and is projected to contribute 15.7% in 2044.

2044 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 4.2. The projections in the table below and the projections for the non-Member capacity in section 4.2 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],
- Short Term Bilateral Capacity[6].

[4] OMU load is net of their allocation of Southeastern Power Administration Cumberland system hydropower.

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

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

Non-Member Energy Sales

Non-Member Sales Under Contract as of 2026	
Calendar Year	MWH
2025	1,336,521
2026	1,372,451
2027[7]	679,600
2028	736,800
2029[8]	322,800

Big Rivers total system energy requirements include the Native system energy requirements described in section 3.6 plus the Non-Member energy requirements described in this section. The following table provides the total system energy requirements.

[7] The OMU contract expires in early 2027.

[8] The current KYMEA contract is set to expire in May 2029. For IRP purposes, Big Rivers assumed the KYMEA contract is extended until 2039 at 50 MWs but this table only represents current firm contracts.

Total System Energy Forecast

Big Rivers Total System Energy Summary (MWh)					
Year	Total Rural Requirements	Direct Serve & Aux Sales	Transmission Losses	Non-Member Requirements[9]	Total System Energy Requirements
2020	2,061,512	824,695	77,120	1,705,329	4,668,657
2021	2,120,806	781,559	71,125	1,646,667	4,620,157
2022	2,159,727	811,577	72,325	1,710,274	4,753,903
2023	2,008,625	1,167,083	78,103	1,670,691	4,924,502
2024	2,087,185	1,623,201	93,173	1,664,068	5,467,627
2025	2,138,920	1,785,062	100,594	1,336,521	5,361,097
2026	2,166,930	1,842,767	102,768	1,372,451	5,484,916
2027	2,187,533	1,861,031	103,674	679,600	4,831,838
2028	2,202,414	1,863,066	104,114	736,800	4,906,393
2029	2,218,153	1,867,091	104,625	322,800	4,512,669
2030	2,228,858	1,871,556	105,016	0	4,205,431
2031	2,247,281	1,876,179	105,613	0	4,229,073
2032	2,271,125	1,880,236	106,336	0	4,257,696
2033	2,293,186	1,884,854	107,027	0	4,285,067
2034	2,316,523	1,888,897	107,736	0	4,313,156
2035	2,337,551	1,893,375	108,397	0	4,339,323
2036	2,355,044	1,898,249	108,975	0	4,362,268
2037	2,378,002	1,902,702	109,685	0	4,390,389
2038	2,398,041	1,907,552	110,329	0	4,415,922
2039	2,417,725	1,912,320	110,961	0	4,441,005
2040	2,434,260	1,917,144	111,513	0	4,462,917
2041	2,451,546	1,922,446	112,096	0	4,486,088
2042	2,468,033	1,927,690	112,657	0	4,508,381
2043	2,481,102	1,932,939	113,129	0	4,527,170
2044	2,492,571	1,938,625	113,571	0	4,544,766
Average Annual Growth Rates					
Previous 10 Years	-1.0%	5.3%	5.5%	-	3.3%
Previous 5 Years	-0.7%	11.4%	2.4%	-	4.0%
Next 5 Years	1.2%	2.8%	2.3%	-	-4.0%
Next 10 Years	1.0%	1.5%	1.5%	-	-2.0%
Next 20 Years	0.9%	0.9%	1.0%	-	-1.0%

[9] The current KYMEA contract is set to expire in May 2029. For IRP purposes, Big Rivers assumed the KYMEA contract is extended until 2039 at 50 MWs but this table only represents current firm contracts.

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 individual consumer historical load factors. 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
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	598,264	598,264	88,521	248	16,102	703,135
2023	490,432	349,748	490,432	225,419	99	17,155	733,105
2024	486,295	486,068	486,295	262,165	104	18,378	766,942
2025	455,173	452,727	455,173	267,211	143	18,061	740,587
2026	460,529	457,380	460,529	273,399	143	18,350	752,420
2027	463,671	459,623	463,671	276,079	143	18,495	758,388
2028	466,205	461,086	466,205	276,577	143	18,571	761,496
2029	468,897	462,639	468,897	277,371	143	18,658	765,068
2030	470,437	463,099	470,437	278,240	143	18,718	767,538
2031	473,604	465,148	473,604	279,118	143	18,819	771,684
2032	477,854	468,247	477,854	279,921	143	18,946	776,863
2033	482,140	470,935	482,140	280,842	143	19,076	782,200
2034	486,736	473,856	486,736	281,648	143	19,211	787,737
2035	490,833	476,400	490,833	282,536	143	19,335	792,847
2036	494,175	478,332	494,175	283,502	143	19,443	797,262
2037	498,687	481,462	498,687	284,392	143	19,578	802,800
2038	502,587	484,119	502,587	285,362	143	19,700	807,791
2039	506,430	486,840	506,430	286,321	143	19,820	812,713
2040	509,638	489,065	509,638	287,290	143	19,924	816,994
2041	513,011	491,601	513,011	288,352	143	20,035	821,541
2042	516,244	494,154	516,244	289,407	143	20,142	825,936
2043	518,799	496,118	518,799	290,465	143	20,233	829,639
2044	521,068	497,854	521,068	291,604	143	20,318	833,133
Average Annual Growth Rates							
Previous 10 Years	0.11%	-2.34%	-2.34%	7.76%	-	5.98%	0.22%
Previous 5 Years	0.25%	-0.20%	-0.19%	17.32%	-	2.82%	4.18%
Next 5 Years	-0.73%	-0.98%	-0.73%	1.13%	6.59%	0.30%	-0.05%
Next 10 Years	0.01%	-0.25%	0.01%	0.72%	3.24%	0.44%	0.27%
Next 20 Years	0.35%	0.12%	0.35%	0.53%	1.61%	0.50%	0.41%

4.2 Non-Member Capacity Sales

Non-Member energy sales have been previously discussed in section 3.7. 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 4.3 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. There is significant change in value due to the ending of the contract with OMU which is not being extended after February 2027, and the expiration of the KYMEA contract in May 2029.[10]

Non-Member Capacity Sales

Non-Member Sales Under Contract as of 2026					
		Season			
		Summer	Fall	Winter	Spring
MISO Planning Year	2025-2026	251	248	182	220
	2026-2027	252	230	185	218
	2027-2028	100	100	100	100
	2028-2029	100	100	100	100

[10] For IRP purposes Big Rivers assumed the KYMEA contract is extended until 2039 at 50 MWs.

4.3 Non-Coincident Peak Demand

The Big Rivers non-coincident peak is defined as the Big Rivers Native CP demand summarized in section 4.1 plus Non-Member sales at their peak load values shown in section 4.2. The table below displays the peak NCP forecast for the total system.

Total System NCP

Total System NCP (kW)			
Year	Total Annual Big Rivers' CP	Non-Member Sales[11]	Total NCP
2020	582,483	349,600	932,083
2021	606,235	345,000	951,235
2022	703,135	508,600	1,211,735
2023	733,105	250,100	983,205
2024	766,942	252,400	1,019,342
2025	740,587	251,000	991,587
2026	752,420	252,000	1,004,420
2027	758,388	218,200	976,588
2028	761,496	100,000	861,496
2029	765,068	100,000	865,068
2030	767,538	0	767,538
2031	771,684	0	771,684
2032	776,863	0	776,863
2033	782,200	0	782,200
2034	787,737	0	787,737
2035	792,847	0	792,847
2036	797,262	0	797,262
2037	802,800	0	802,800
2038	807,791	0	807,791
2039	812,713	0	812,713
2040	816,994	0	816,994
2041	821,541	0	821,541
2042	825,936	0	825,936

[11] For IRP purposes Big Rivers assumed the KYMEA contract is extended until 2039 at 50 MWs.

5 DSM IMPACT SCENARIO

Big Rivers selected GDS Associates to complete a Demand-Side Management ("DSM") Market Potential Study in 2026 that had five primary objectives: Develop databases of energy efficiency and demand response measures, evaluate the electric DSM technical potential savings, calculate the Total Resource Cost ("TRC") test benefit-cost ratio for potential electric energy efficiency measures, evaluate the potential for achievable savings through DSM programs over a fifteen-year horizon, and estimate the potential savings over that fifteen-year period based on specific funding levels.

The results of the study showed large variances in potential energy and dollar savings depending on the level of investment. With levels of $0.5 million, $1.5 million, and $2.5 million studied over the fifteen-year period, the cumulative savings of energy varied from about 23,000 MWhs to 109,000 MWhs by 2040. The table below shows the estimated cumulative energy and peak savings for each investment level.

DSM Scenario Impacts

	2027	2030	2035	2040
Annual Energy (MWh)				
Program - $2.5 million	8,734	35,946	78,210	109,438
Program – $1.5 million	**5,479**	**22,545**	**49,091**	**67,730**
Program - $0.5 million	1,887	7,760	16,700	22,830
Summer Peak Demand (MW)				
Program – $2.5 million	**7.9**	**44.4**	**60.8**	**65.7**
Program - $1.5 million	3.7	32.2	46.7	50.3
Program – $0.5 million	**2.0**	**16.4**	**19.8**	**19.9**
Winter Peak Demand (MW)				
Program - $2.5 million	8.4	42.7	60.0	64.0
Program – $1.5 million	**3.8**	**29.6**	**41.4**	**44.2**
Program - $0.5 million	2.1	16.9	20.0	19.7

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
2020		2,164,868			440,685			460,173	
2021		2,219,380			492,854			487,669	
2022		2,269,586			598,264			510,098	
2023		2,097,660			349,748			490,432	
2024		2,179,785			486,068			486,295	
2025	2,104,022	2,238,259	2,404,608	392,357	452,727	547,497	419,768	455,173	520,643
2026	2,133,698	2,267,529	2,433,184	397,201	457,380	551,443	425,194	460,529	524,781
2027	2,152,740	2,285,503	2,449,682	399,984	459,623	552,226	428,504	463,671	526,266
2028	2,169,431	2,301,046	2,463,641	402,053	461,086	552,100	431,223	466,205	527,097
2029	2,186,892	2,317,481	2,478,663	404,151	462,639	552,259	434,033	468,897	528,212
2030	2,199,358	2,328,667	2,488,146	405,250	463,099	551,207	435,728	470,437	528,141
2031	2,219,316	2,347,896	2,506,342	407,696	465,148	552,181	438,890	473,604	530,058
2032	2,244,553	2,372,775	2,530,650	411,023	468,247	554,485	443,017	477,854	533,264
2033	2,267,547	2,395,795	2,553,589	413,890	470,935	556,556	447,000	482,140	537,259
2034	2,291,702	2,420,143	2,578,068	416,924	473,856	559,038	451,237	486,736	541,749
2035	2,313,493	2,442,083	2,600,095	419,580	476,400	561,176	454,998	490,833	545,762
2036	2,331,705	2,460,336	2,618,314	421,653	478,332	562,695	458,043	494,175	549,011
2037	2,355,216	2,484,286	2,642,711	424,743	481,462	565,727	462,163	498,687	553,655
2038	2,375,750	2,505,191	2,663,989	427,370	484,119	568,307	465,703	502,587	557,690
2039	2,395,820	2,525,724	2,685,013	430,007	486,840	571,065	469,179	506,430	561,743
2040	2,412,676	2,542,976	2,702,680	432,165	489,065	573,332	472,052	509,638	565,159
2041	2,430,151	2,561,009	2,721,333	434,543	491,601	576,097	475,069	513,011	568,835
2042	2,446,694	2,578,209	2,739,282	436,877	494,154	579,036	477,943	516,244	572,438
2043	2,459,811	2,591,846	2,753,505	438,676	496,118	581,298	480,187	518,799	575,300
2044	2,471,297	2,603,815	2,766,017	440,263	497,854	583,301	482,166	521,068	577,875

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
2020		3,083,627			570,433			582,483	
2021		3,090,431			606,235			601,789	
2022		3,159,672			703,135			644,996	
2023		3,343,678			639,688			733,105	
2024		3,897,094			734,883			766,942	
2025	3,987,257	4,124,850	4,295,356	666,612	728,492	833,809	705,088	740,587	808,931
2026	4,076,823	4,213,999	4,383,795	679,395	741,078	838,040	716,995	752,420	819,515
2027	4,115,061	4,251,143	4,419,426	684,109	745,238	841,636	723,139	758,388	823,784
2028	4,134,254	4,269,159	4,435,819	686,781	747,290	842,071	726,442	761,496	825,141
2029	4,156,278	4,290,131	4,455,342	689,773	749,723	843,085	730,141	765,068	827,093
2030	4,173,633	4,306,175	4,469,640	691,817	751,112	842,932	732,774	767,538	827,907
2031	4,198,829	4,330,623	4,493,029	695,245	754,133	844,859	736,920	771,684	830,769
2032	4,228,854	4,360,282	4,522,102	699,505	758,160	848,079	741,978	776,863	834,875
2033	4,257,157	4,388,610	4,550,349	703,417	761,889	851,186	747,010	782,200	839,910
2034	4,286,059	4,417,711	4,579,584	707,382	765,737	854,594	752,184	787,737	845,335
2035	4,312,984	4,444,789	4,606,751	711,044	769,283	857,734	756,954	792,847	850,356
2036	4,336,648	4,468,495	4,630,421	714,185	772,282	860,318	761,070	797,262	854,671
2037	4,365,311	4,497,607	4,659,992	718,295	776,432	864,377	766,210	802,800	860,340
2038	4,391,329	4,524,006	4,686,774	722,012	780,180	868,057	770,837	807,791	865,466
2039	4,416,789	4,549,940	4,713,210	725,728	783,982	871,908	775,387	812,713	870,599
2040	4,439,011	4,572,567	4,736,264	728,963	787,286	875,265	779,330	816,994	875,089
2041	4,462,357	4,596,485	4,760,818	732,522	791,005	879,229	783,517	821,541	879,942
2042	4,484,689	4,619,491	4,784,591	736,026	794,735	883,365	787,549	825,936	884,712
2043	4,503,513	4,638,848	4,804,549	738,986	797,864	886,811	790,938	829,639	888,726
2044	4,521,115	4,656,945	4,823,202	741,813	800,843	890,074	794,139	833,133	892,529

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 2025. 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 2044 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
2020		2,164,868			440,685			460,173	
2021		2,219,380			492,854			487,669	
2022		2,269,586			598,264			510,098	
2023		2,097,660			349,748			490,432	
2024		2,179,785			486,068			486,295	
2025	2,225,211	2,238,259	2,251,333	452,319	452,727	453,134	452,295	455,173	457,307
2026	2,229,811	2,267,529	2,305,418	452,036	457,380	462,740	452,639	460,529	467,555
2027	2,222,967	2,285,503	2,348,496	449,323	459,623	469,982	450,746	463,671	476,692
2028	2,213,613	2,301,046	2,389,365	445,835	461,086	476,470	448,237	466,205	484,359
2029	2,205,045	2,317,481	2,431,378	442,435	462,639	483,075	445,867	468,897	492,231
2030	2,191,530	2,328,667	2,467,978	438,011	463,099	488,548	442,412	470,437	498,914
2031	2,185,563	2,347,896	2,513,272	435,099	465,148	495,715	440,485	473,604	507,352
2032	2,184,803	2,372,775	2,564,818	433,163	468,247	504,038	439,553	477,854	516,996
2033	2,182,121	2,395,795	2,614,720	430,823	470,935	511,971	438,610	482,140	526,754
2034	2,180,490	2,420,143	2,666,392	428,677	473,856	520,206	437,910	486,736	536,924
2035	2,176,510	2,442,083	2,715,752	426,170	476,400	528,079	436,719	490,833	546,618
2036	2,169,118	2,460,336	2,761,294	423,106	478,332	535,314	434,825	494,175	555,535
2037	2,166,529	2,484,286	2,813,628	421,077	481,462	543,947	433,915	498,687	565,850
2038	2,161,064	2,505,191	2,862,906	418,604	484,119	552,107	432,424	502,587	575,554
2039	2,155,038	2,525,724	2,912,177	416,155	486,840	560,405	430,836	506,430	585,279
2040	2,145,988	2,542,976	2,958,058	413,256	489,065	568,192	428,661	509,638	594,351
2041	2,137,363	2,561,009	3,005,266	410,588	491,601	576,404	426,579	513,011	603,699
2042	2,127,761	2,578,209	3,051,964	407,897	494,154	584,709	424,326	516,244	612,975
2043	2,114,978	2,591,846	3,094,857	404,688	496,118	592,383	421,470	518,799	621,527
2044	2,100,581	2,603,815	3,136,195	401,261	497,854	599,849	418,335	521,068	629,820

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
2020		3,083,627			570,433			582,483	
2021		3,090,431			606,235			601,789	
2022		3,159,672			703,135			644,996	
2023		3,343,678			639,688			733,105	
2024		3,897,094			734,883			766,942	
2025	4,101,448	4,124,850	4,148,278	727,854	728,492	729,130	736,040	740,587	745,396
2026	4,146,153	4,213,999	4,282,020	732,653	741,078	749,520	739,896	752,420	765,098
2027	4,138,492	4,251,143	4,364,262	728,974	745,238	761,565	737,830	758,388	779,044
2028	4,111,840	4,269,159	4,427,387	723,193	747,290	771,522	732,920	761,496	790,262
2029	4,087,900	4,290,131	4,493,860	717,770	749,723	781,915	728,432	765,068	802,016
2030	4,059,232	4,306,175	4,555,344	711,351	751,112	791,242	722,889	767,538	812,649
2031	4,038,361	4,330,623	4,626,003	706,469	754,133	802,328	718,902	771,684	825,110
2032	4,022,196	4,360,282	4,702,540	702,502	758,160	814,541	715,847	776,863	838,742
2033	4,004,504	4,388,610	4,778,099	698,218	761,889	826,505	712,874	782,200	852,638
2034	3,987,261	4,417,711	4,854,922	694,005	765,737	838,669	710,025	787,737	866,846
2035	3,967,926	4,444,789	4,929,951	689,481	769,283	850,571	706,731	792,847	880,677
2036	3,945,360	4,468,495	5,001,612	684,437	772,282	861,926	702,769	797,262	893,816
2037	3,927,242	4,497,607	5,079,848	680,367	776,432	874,649	699,728	802,800	908,322
2038	3,906,435	4,524,006	5,155,504	675,895	780,180	886,999	696,144	807,791	922,313
2039	3,884,882	4,549,940	5,231,158	671,417	783,982	899,499	692,430	812,713	936,332
2040	3,860,180	4,572,567	5,303,501	666,466	787,286	911,506	688,105	816,994	949,713
2041	3,836,225	4,596,485	5,377,873	661,814	791,005	924,082	683,935	821,541	963,510
2042	3,811,110	4,619,491	5,451,761	657,108	794,735	936,768	679,561	825,936	977,244
2043	3,782,630	4,638,848	5,521,863	651,852	797,864	948,832	674,550	829,639	990,262
2044	3,752,751	4,656,945	5,591,015	646,419	800,843	960,805	669,298	833,133	1,003,137

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
2015	2,325,204	2,327,573	566,553	529,903	504,990	493,941
2016	2,330,037	2,306,691	484,768	472,504	486,690	483,416
2017	2,209,837	2,278,398	474,971	461,804	504,269	506,260
2018	2,366,988	2,281,981	556,742	518,925	502,549	467,191
2019	2,261,069	2,240,765	490,895	460,244	480,171	492,492
2020	2,164,868	2,203,580	440,685	451,886	460,173	500,823
2021	2,219,380	2,240,148	492,854	445,226	487,669	495,980
2022	2,269,586	2,238,760	598,264	475,912	510,098	493,521
2023	2,097,660	2,201,777	349,748	392,330	490,432	490,062
2024	2,179,785	2,227,307	486,068	447,144	486,295	475,982

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
2015	3,339,047	3,341,502	698,949	661,699	629,640	625,487
2016	3,318,766	3,294,901	612,568	605,377	621,295	617,946
2017	3,207,660	3,277,887	606,671	593,204	634,184	636,226
2018	3,407,668	3,320,449	668,654	629,887	626,212	610,132
2019	3,294,392	3,273,564	624,821	593,366	619,553	633,390
2020	3,083,627	3,123,333	570,433	578,270	582,483	596,423
2021	3,090,431	3,111,698	606,235	567,018	601,789	610,294
2022	3,159,672	3,128,126	703,135	569,467	644,996	610,363
2023	3,343,678	3,450,275	639,688	683,290	733,105	732,726
2024	3,897,094	3,945,787	734,883	695,026	766,942	733,537

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 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)[12], electric vehicle and distributed generation projections from the EIA, electric vehicle load shapes from the Department of Energy Alternative Fuels Data Center[13], distributed generation load shapes from the National Renewable Energy Laboratory (NREL)[14], monthly and daily weather data from the Midwest Regional Climate Center (MRCC)[15] and High Plains Regional Climate Center (HPRCC)[16], 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 2025.

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.

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

[13] https://afdc.energy.gov/vehicles/electric.html

[14] https://pvwatts.nrel.gov/

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

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

County-level economic and demographic data was gathered and added to the energy database. 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 2025 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 2.6% 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 2023 Load Forecast

The 2023 and 2025 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. Individual consumer load factors were used in the creation of the Direct Serve peak forecasts. In previous load forecasts a class average load factor at each Member system was used.

9 TRACKING ANALYSIS

9.1 TRACKING 2015 THROUGH 2023 FORECASTS TO ACTUAL VALUES

The following section provides a tracking analysis comparing portions of the 2015, 2017, 2020, and 2023 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 2015 and 2017 forecasts. The 2023 forecast was close to actual consumer counts in 2024. This forecast over-projected consumer counts by 0.23%.

Total Consumer Tracking Analysis

Comparison of Consumer Forecasts										
Year	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	2023 Forecast Compared to Actual	2025 Load Forecast
2010	112,410									
2011	112,885									
2012	113,250									
2013	113,717									
2014	114,208									
2015	114,934	114,864	-0.06%							
2016	115,852	115,694	-0.14%							
2017	116,898	116,511	-0.33%	116,843	-0.05%					
2018	117,369	117,529	0.14%	117,809	0.38%					
2019	117,782	118,538	0.64%	118,737	0.81%					
2020	118,684	119,523	0.71%	119,781	0.92%	118,667	-0.01%			
2021	119,625	120,465	0.70%	120,701	0.90%	119,616	-0.01%			
2022	120,496	121,386	0.74%	121,568	0.89%	120,474	-0.02%			
2023	120,979	122,313	1.10%	122,434	1.20%	121,218	0.20%	121,391	0.34%	
2024	121,892	123,206	1.08%	123,299	1.15%	121,886	-0.01%	122,169	0.23%	
2025		**124,067**		**124,197**		**122,470**		**123,046**		**122,829**
2026		**124,910**		**125,044**		**122,883**		**123,832**		**123,664**
2027		**125,712**		**125,822**		**123,157**		**124,516**		**124,451**
2028		**126,511**		**126,786**		**123,391**		**125,164**		**125,189**
2029				**127,688**		**123,579**		**125,773**		**125,883**
2030				**128,589**		**123,723**		**126,346**		**126,536**
2031				**129,438**		**123,830**		**126,894**		**127,145**
2032				**130,286**		**123,901**		**127,413**		**127,717**
2033				**131,134**		**123,947**		**127,910**		**128,258**
2034				**131,983**		**123,976**		**128,389**		**128,782**
2035				**132,831**		**123,991**		**128,856**		**129,292**
2036				**133,680**		**123,997**		**129,311**		**129,784**
2037						**124,003**		**129,758**		**130,261**
2038						**124,014**		**130,195**		**130,725**
2039						**124,033**		**130,624**		**131,179**
2040								**131,052**		**131,624**
2041								**131,491**		**132,067**
2042								**131,949**		**132,521**
2043										**132,993**
2044										**133,481**

The following table provides a breakdown of the 2023 and 2025 forecasted consumer values by Residential and GCI class. The 2023 forecast study over-projected 2024 Residential consumers by 2,345. The GCI consumer count for 2024 was under-projected by 2,036 in the 2023 forecast study. Most of these differences are explained by a Residential to GCI reclassification that occurred in 2023.

Consumer Tracking Analysis by Class

Comparison of Consumer Forecasts by Class								
Year	Residential Actual	2023 Residential Load Forecast	2023 Forecast Compared to Actual	2025 Residential Load Forecast	GCI Actual	2023 GCI Load Forecast	2023 Forecast Compared to Actual	2025 GCI Load Forecast
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				16,806			
2016	98,583				17,096			
2017	99,451				17,276			
2018	99,724				17,469			
2019	99,871				17,736			
2020	100,257				18,249			
2021	100,954				18,489			
2022	101,506				18,801			
2023	100,036	102,118	2.08%		20,736	19,096	-7.91%	
2024	100,519	102,864	2.33%		21,160	19,124	-9.62%	
2025		**103,563**		**101,190**		**19,302**		**21,427**
2026		**104,147**		**101,840**		**19,505**		**21,611**
2027		**104,633**		**102,447**		**19,702**		**21,789**
2028		**105,087**		**103,017**		**19,896**		**21,958**
2029		**105,504**		**103,543**		**20,089**		**22,126**
2030		**105,888**		**104,029**		**20,278**		**22,292**
2031		**106,248**		**104,472**		**20,467**		**22,458**
2032		**106,580**		**104,880**		**20,653**		**22,622**
2033		**106,891**		**105,257**		**20,839**		**22,786**
2034		**107,185**		**105,617**		**21,024**		**22,951**
2035		**107,467**		**105,961**		**21,209**		**23,115**
2036		**107,737**		**106,289**		**21,394**		**23,280**
2037		**108,000**		**106,601**		**21,579**		**23,446**
2038		**108,251**		**106,899**		**21,764**		**23,612**
2039		**108,493**		**107,186**		**21,951**		**23,777**
2040		**108,734**		**107,464**		**22,138**		**23,944**
2041		**108,984**		**107,740**		**22,326**		**24,112**
2042		**109,252**		**108,025**		**22,517**		**24,281**
2043				**108,326**				**24,452**
2044				**108,641**				**24,625**

The following table compares the 2015, 2017, 2020 and 2023 forecasts to actual energy values for the Native system. The four forecasts over-projected 2023 energy values by an average of 17.1%. Actual values in 2024 were over-projected by an average of 5.1% across the forecasts. Comparing the prior forecasts to weather normalized energy values explains some of the fluctuation. 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)											
Year	Actual	Weather Normalization	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	2023 Forecast Compared to Actual	2025 Load Forecast
2010											
2011											
2012	3,290	3,303									
2013	3,385	3,376									
2014	3,382	3,313									
2015	3,272	3,274	3,318	1.40%							
2016	3,245	3,222	3,413	5.17%							
2017	3,130	3,198	3,452	10.30%	3,259	4.13%					
2018	3,321	3,236	3,469	4.46%	3,343	0.67%					
2019	3,212	3,191	3,486	8.55%	3,433	6.90%					
2020	3,007	3,045	3,496	16.28%	3,473	15.52%	3,302	9.81%			
2021	3,019	3,040	3,514	16.38%	3,475	15.09%	3,330	10.28%			
2022	3,087	3,057	3,536	14.53%	3,479	12.69%	4,384	42.00%			
2023	3,266	3,370	3,560	9.02%	3,481	6.60%	4,396	34.61%	3,860	18.21%	
2024	3,804	3,851	3,581	-5.86%	3,490	-8.25%	4,409	15.90%	4,516	18.72%	
2025			**3,602**		**3,495**		**4,416**		**4,569**		**4,024**
2026			**3,624**		**3,502**		**4,425**		**4,580**		**4,111**
2027			**3,642**		**3,509**		**4,427**		**4,590**		**4,147**
2028			**3,669**		**3,521**		**4,437**		**4,601**		**4,165**
2029			**3,691**		**3,526**		**4,439**		**4,606**		**4,186**
2030			**3,714**		**3,535**		**4,443**		**4,620**		**4,201**
2031			**3,737**		**3,544**		**4,448**		**4,630**		**4,225**
2032			**3,760**		**3,557**		**4,458**		**4,653**		**4,254**
2033			**3,782**		**3,562**		**4,463**		**4,658**		**4,282**
2034			**3,805**		**3,572**		**4,467**		**4,667**		**4,310**
2035					**3,581**		**4,471**		**4,677**		**4,336**
2036					**3,593**		**4,475**		**4,695**		**4,360**
2037							**4,479**		**4,701**		**4,388**
2038							**4,483**		**4,710**		**4,414**
2039							**4,487**		**4,719**		**4,439**
2040									**4,729**		**4,461**
2041									**4,735**		**4,484**
2042									**4,744**		**4,507**
2043											**4,526**
2044											**4,543**

The following table provides a breakdown of the 2023 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 4.6% high during the 2023-2024 forecast period. The GCI forecast was an average of 2.6% high during the 2023-2024 forecast period compared to weather normalized actual values.

Energy Tracking Analysis by Class

Comparison of Class Energy Forecasts (GWh)												
Year	Residential Actual	Residential Weather Normalization	2023 Residential Load Forecast	2023 Forecast Compared to Actual	2023 Forecast Compared to Weather Normalization	2025 Residential Load Forecast	GCI Actual	GCI Weather Normalization	2023 GCI Load Forecast	2023 Forecast Compared to Actual	2023 Forecast Compared to Weather Normalization	2025 GCI Load Forecast
2010	1,611	1,484					619	591				
2011	1,530	1,513					600	596				
2012	1,466	1,479					595	594				
2013	1,510	1,502					601	601				
2014	1,532	1,475					610	601				
2015	1,448	1,448					611	614				
2016	1,436	1,420					597	590				
2017	1,348	1,401					582	594				
2018	1,491	1,430					600	580				
2019	1,411	1,396					572	567				
2020	1,360	1,390					533	540				
2021	1,395	1,411					557	562				
2022	1,430	1,406					563	558				
2023	1,288	1,368	1,438	11.65%	5.11%		556	576	591	6.37%	2.71%	
2024	1,351	1,389	1,446	7.06%	4.13%		575	582	597	3.83%	2.47%	
2025			**1,446**			**1,393**			**598**			**586**
2026			**1,451**			**1,405**			**603**			**596**
2027			**1,455**			**1,414**			**608**			**607**
2028			**1,460**			**1,422**			**614**			**614**
2029			**1,465**			**1,432**			**620**			**619**
2030			**1,471**			**1,439**			**628**			**623**
2031			**1,475**			**1,450**			**634**			**630**
2032			**1,484**			**1,465**			**645**			**638**
2033			**1,486**			**1,480**			**649**			**645**
2034			**1,489**			**1,495**			**654**			**653**
2035			**1,493**			**1,509**			**661**			**660**
2036			**1,499**			**1,520**			**669**			**666**
2037			**1,502**			**1,534**			**674**			**674**
2038			**1,506**			**1,547**			**680**			**682**
2039			**1,509**			**1,558**			**685**			**689**
2040			**1,511**			**1,569**			**689**			**695**
2041			**1,514**			**1,580**			**694**			**701**
2042			**1,518**			**1,591**			**700**			**706**
2043						**1,600**						**710**
2044						**1,608**						**713**

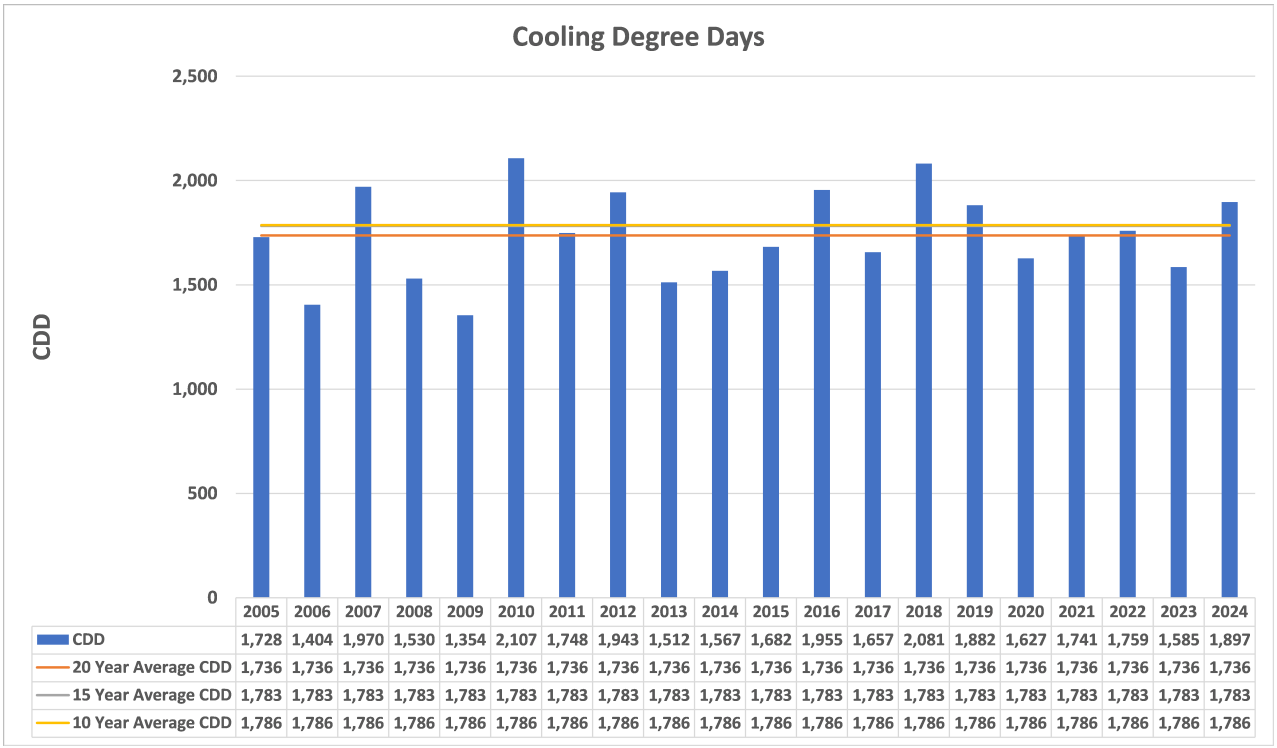
The following table compares the 2015, 2017, 2020, and 2023 forecasts to actual peak values for the Native system. The four forecasts over-projected 2023 peak values by an average of 1.4%. The 2024 actual values were over-projected by an average of 0.02% across the four forecasts. The over-projection of peak on the 2023 load forecast is due to a delay and change in specifications in a new Direct Serve load.

Native Peak Tracking Analysis

Comparison of Native Peak Forecasts (MW)											
Year	Actual	Weather Normalization	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	2023 Forecast Compared to Actual	2025 Load Forecast
2010	662	615									
2011	659	649									
2012	661	619									
2013	617	636									
2014	750	651									
2015	699	662	661	-5.43%							
2016	621	618	683	9.93%							
2017	634	636	691	8.96%	648	2.18%					
2018	669	630	693	3.64%	660	-1.29%					
2019	625	633	695	11.23%	673	7.71%					
2020	582	596	697	19.66%	676	16.05%	627	7.59%			
2021	606	610	701	15.63%	678	11.84%	632	4.27%			
2022	703	610	704	0.12%	679	-3.43%	832	18.39%			
2023	733	733	707	-3.56%	680	-7.24%	835	13.84%	752	2.60%	
2024	767	734	711	-7.29%	681	-11.21%	836	9.05%	840	9.52%	
2025			**715**		**682**		**838**		**861**		**741**
2026			**720**		**683**		**840**		**863**		**752**
2027			**724**		**685**		**840**		**865**		**758**
2028			**729**		**686**		**841**		**868**		**761**
2029			**734**		**688**		**843**		**869**		**765**
2030			**740**		**689**		**843**		**872**		**768**
2031			**745**		**691**		**844**		**874**		**772**
2032			**750**		**693**		**846**		**878**		**777**
2033			**755**		**695**		**847**		**879**		**782**
2034			**761**		**696**		**848**		**881**		**788**
2035					**698**		**849**		**883**		**793**
2036					**700**		**850**		**886**		**797**
2037							**851**		**888**		**803**
2038							**851**		**890**		**808**
2039							**852**		**892**		**813**
2040									**893**		**817**
2041									**895**		**822**
2042									**896**		**826**
2043											**830**
2044											**833**

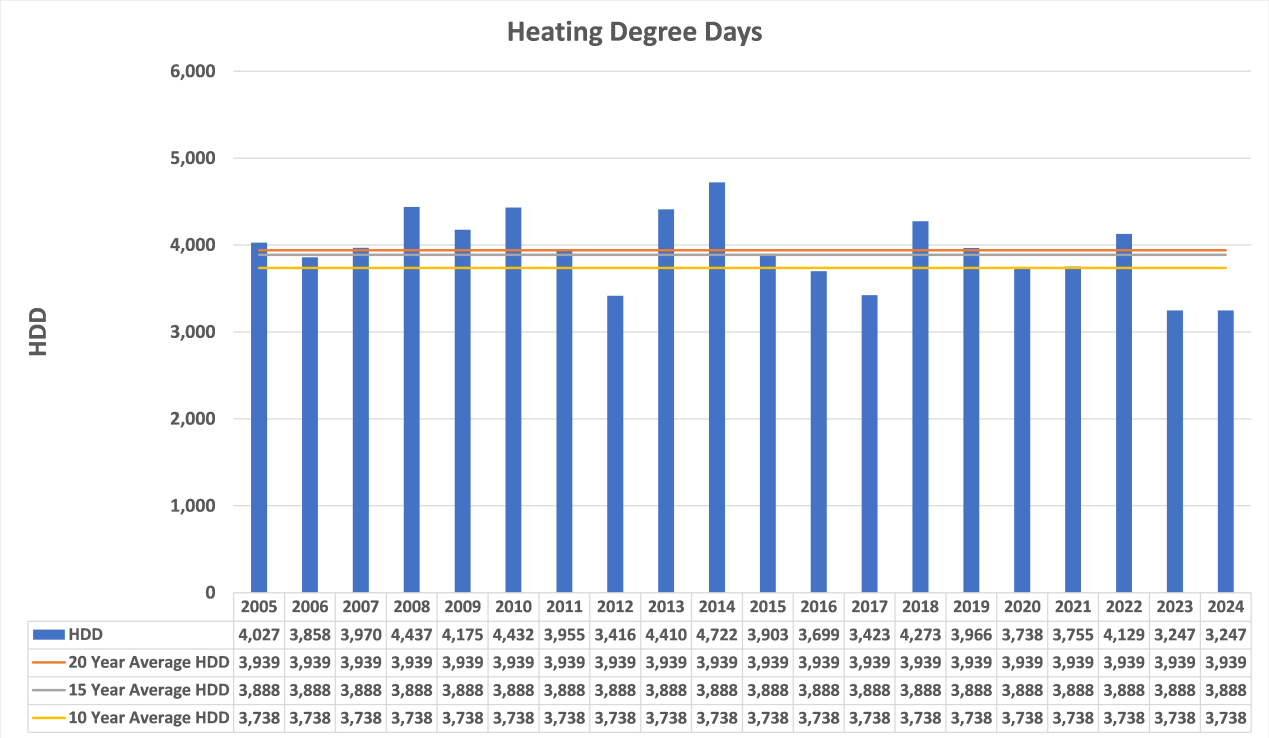
The historical weather normalized values in this section were completed using twenty-year average values as the definition for normal weather. This is consistent with the normal weather definition used throughout the forecast. If the time span used to define normal weather is shortened to a ten-year 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 nearly identical to the ten-year average and the HDD values would be very close to the twenty-year average. 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



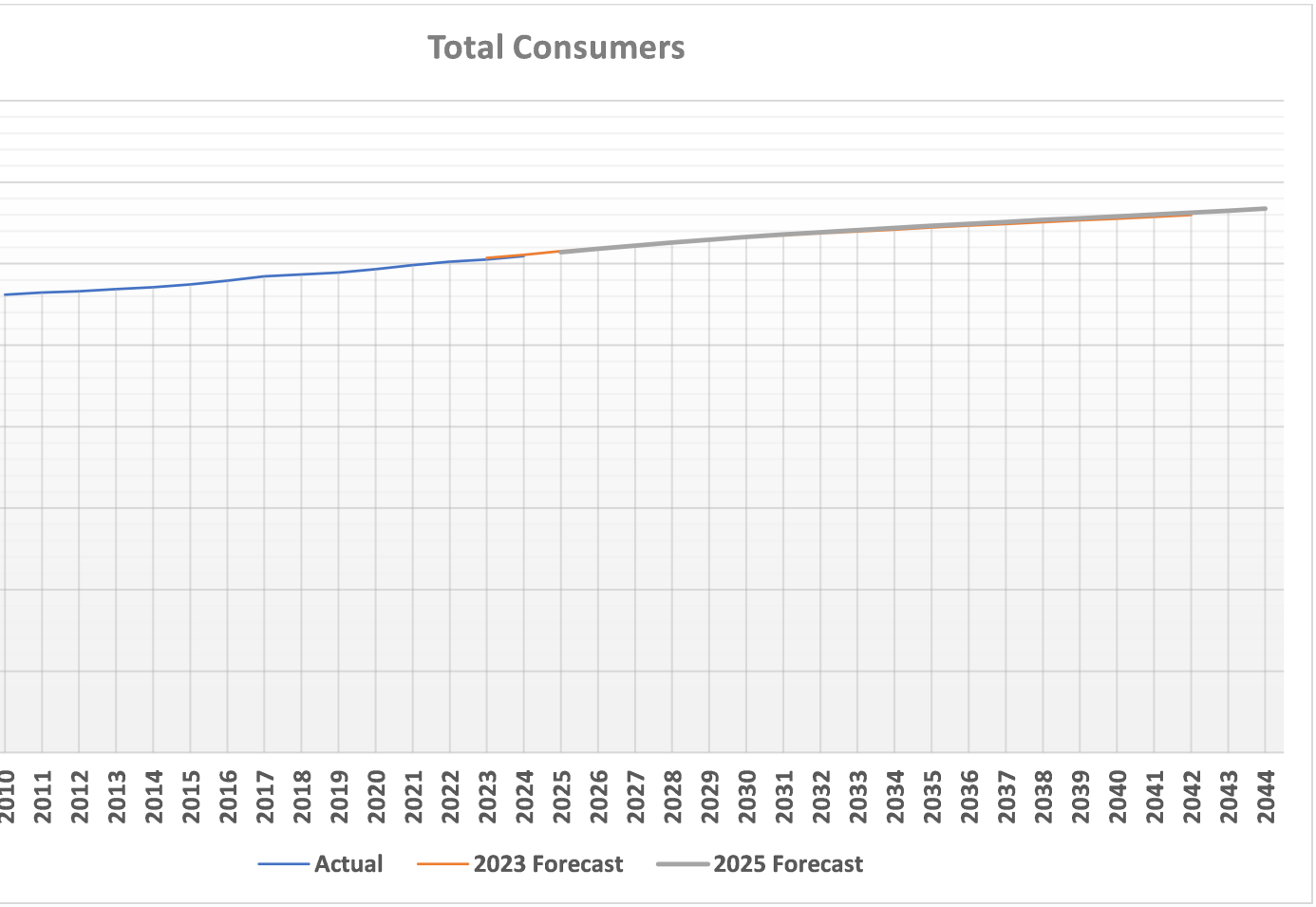
	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CDD	1,728	1,404	1,970	1,530	1,354	2,107	1,748	1,943	1,512	1,567	1,682	1,955	1,657	2,081	1,882	1,627	1,741	1,759	1,585	1,897
20 Year Average CDD	1,736	1,736	1,736	1,736	1,736	1,736	1,736	1,736	1,736	1,736	1,736	1,736	1,736	1,736	1,736	1,736	1,736	1,736	1,736	1,736
15 Year Average CDD	1,783	1,783	1,783	1,783	1,783	1,783	1,783	1,783	1,783	1,783	1,783	1,783	1,783	1,783	1,783	1,783	1,783	1,783	1,783	1,783
10 Year Average CDD	1,786	1,786	1,786	1,786	1,786	1,786	1,786	1,786	1,786	1,786	1,786	1,786	1,786	1,786	1,786	1,786	1,786	1,786	1,786	1,786

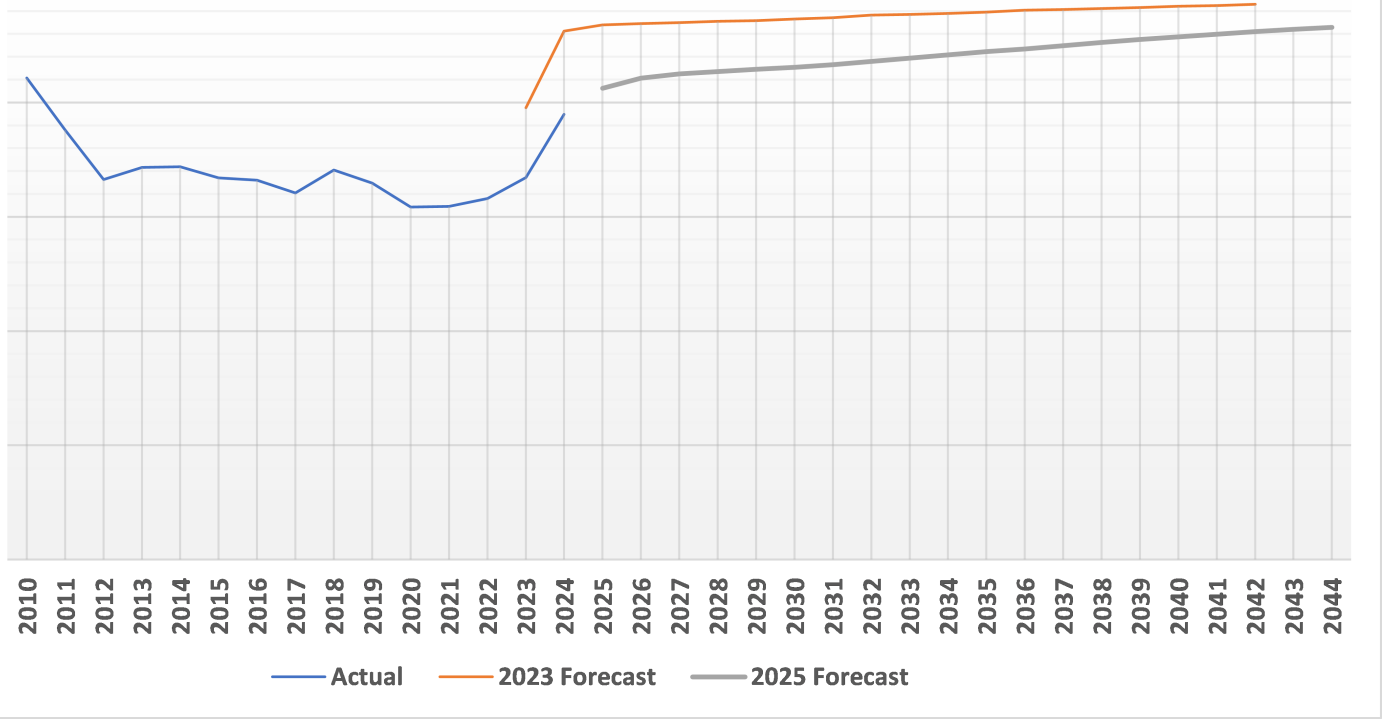
Heating Degree Day Normal Values



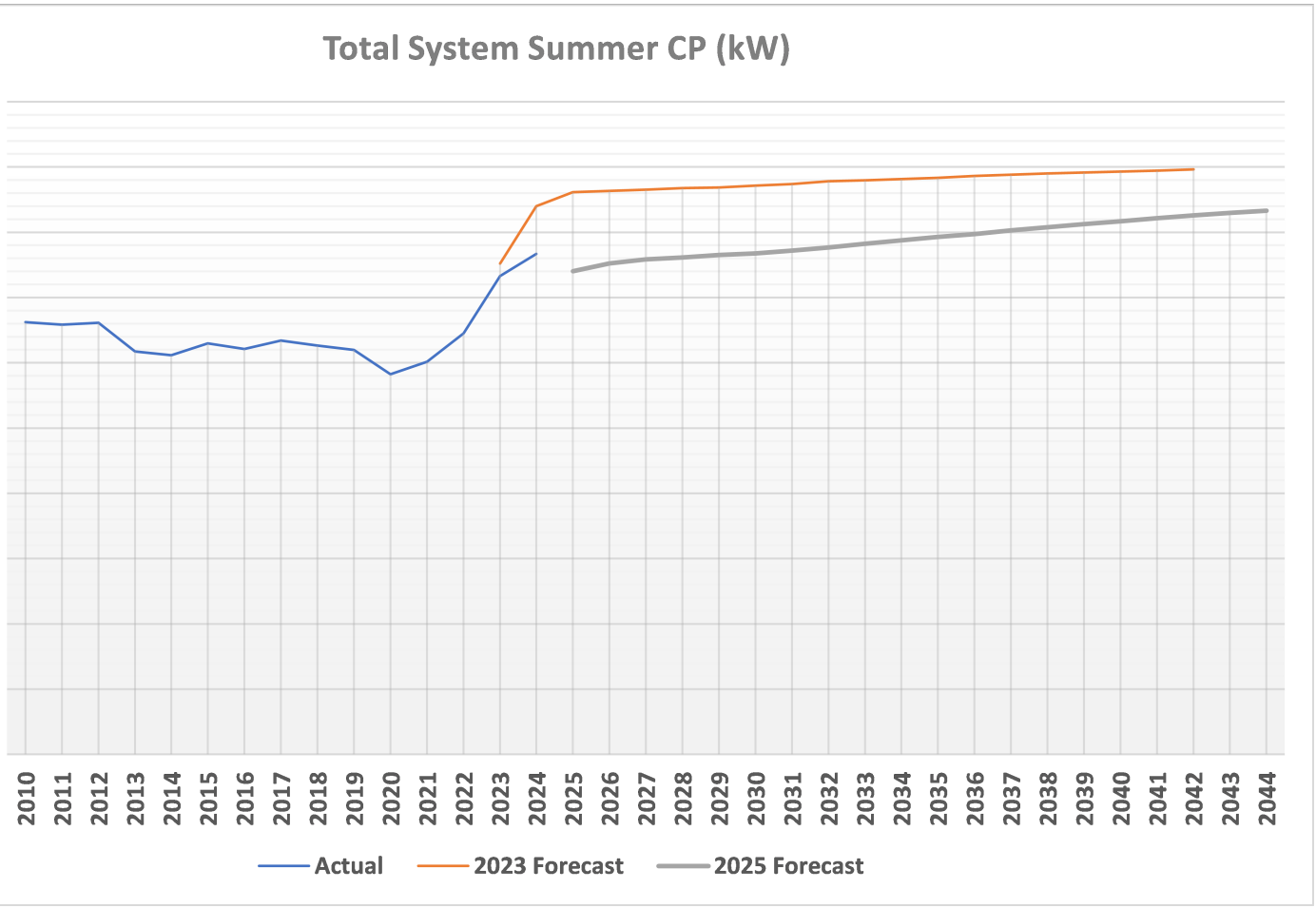
	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
HDD	4,027	3,858	3,970	4,437	4,175	4,432	3,955	3,416	4,410	4,722	3,903	3,699	3,423	4,273	3,966	3,738	3,755	4,129	3,247	3,247
20 Year Average HDD	3,939	3,939	3,939	3,939	3,939	3,939	3,939	3,939	3,939	3,939	3,939	3,939	3,939	3,939	3,939	3,939	3,939	3,939	3,939	3,939
15 Year Average HDD	3,888	3,888	3,888	3,888	3,888	3,888	3,888	3,888	3,888	3,888	3,888	3,888	3,888	3,888	3,888	3,888	3,888	3,888	3,888	3,888
10 Year Average HDD	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738

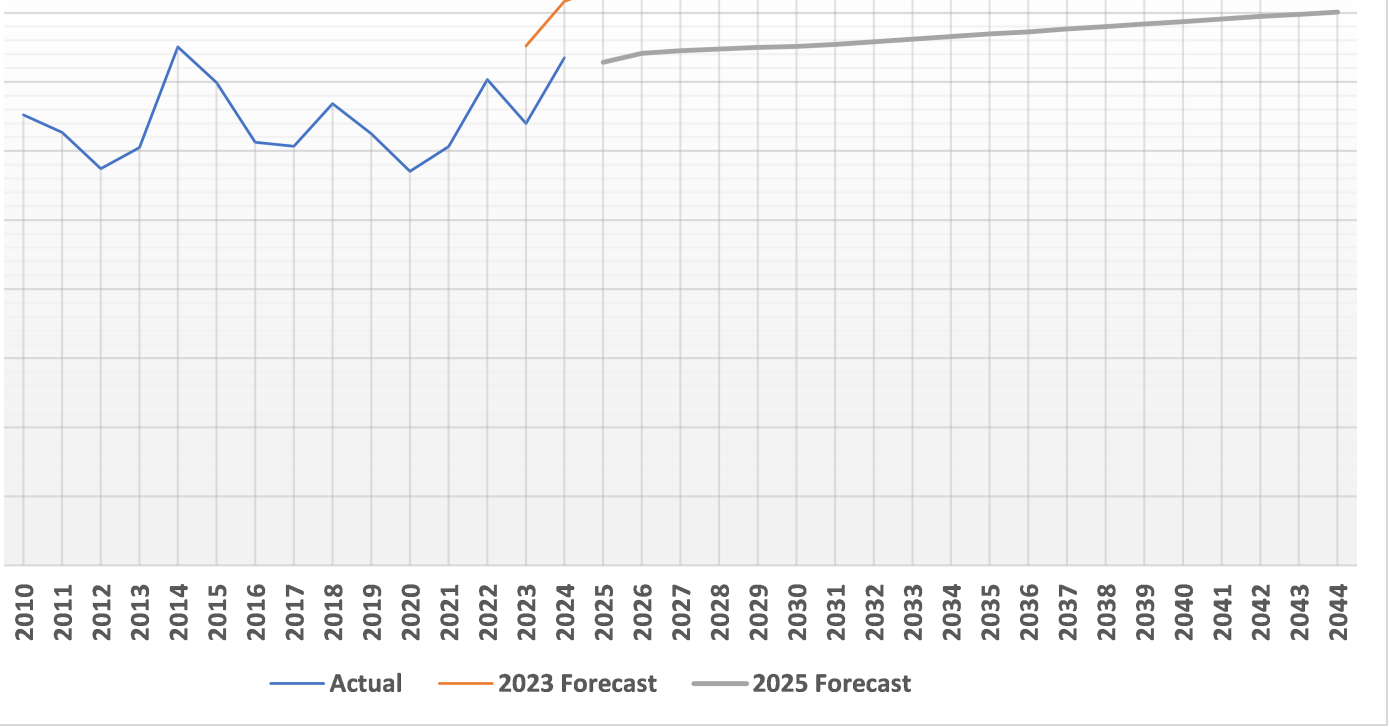
2023 Forecast Total Consumers Comparison



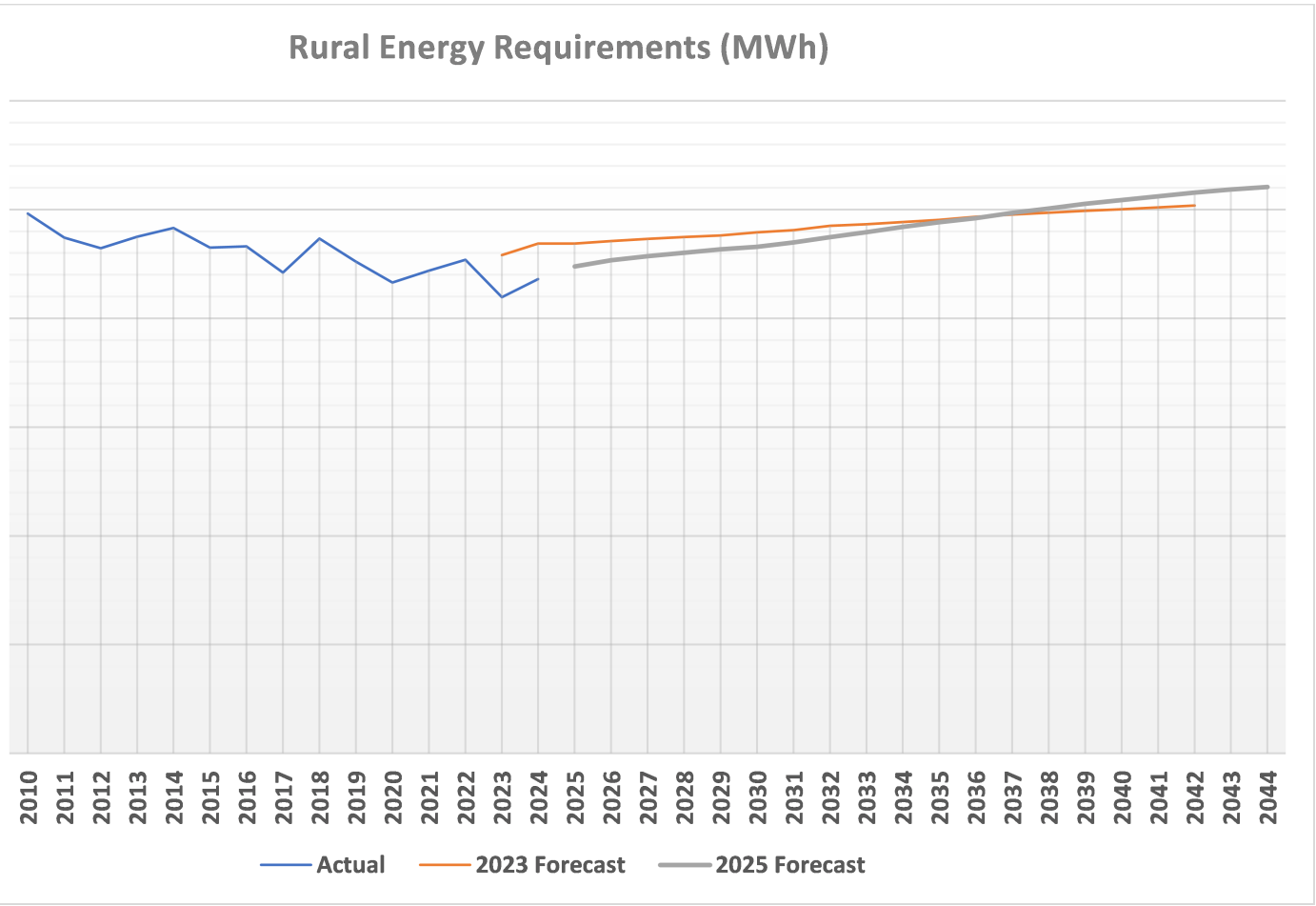


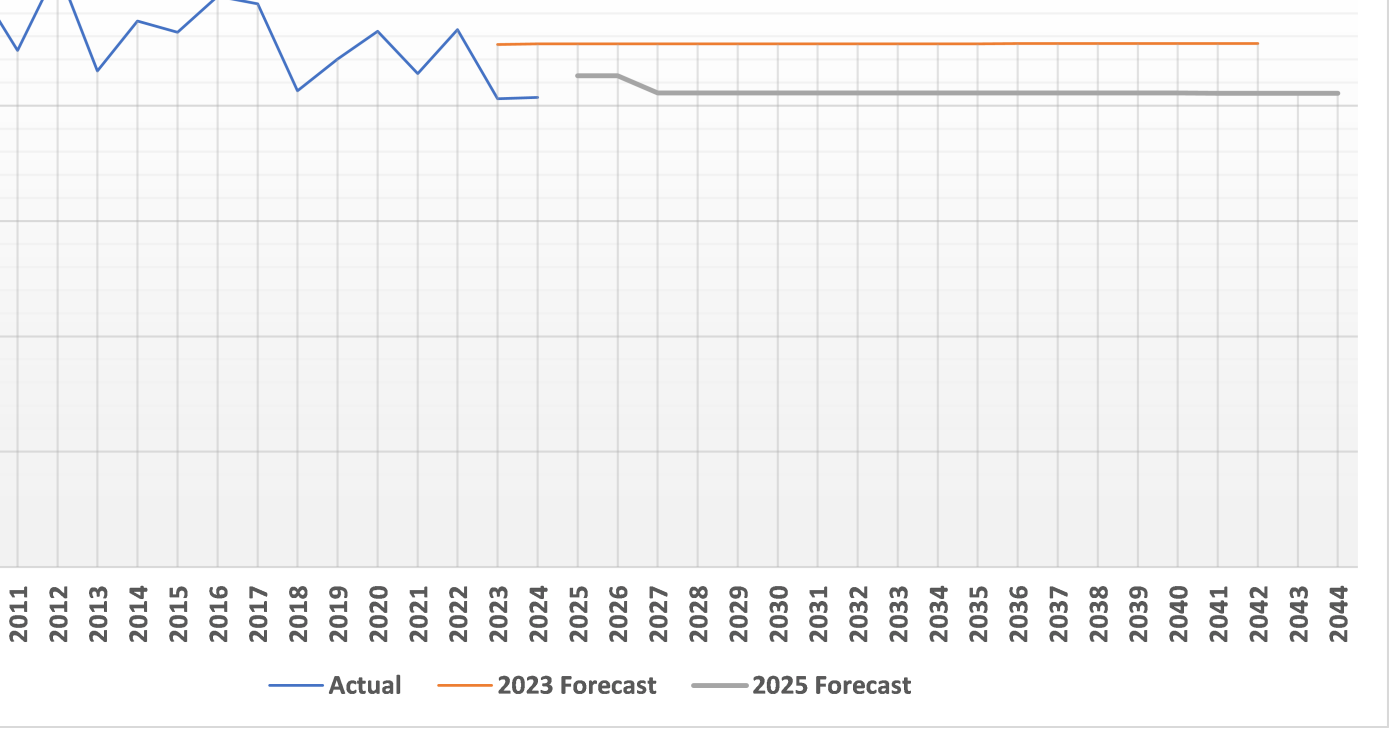
2023 Forecast Summer CP Comparison



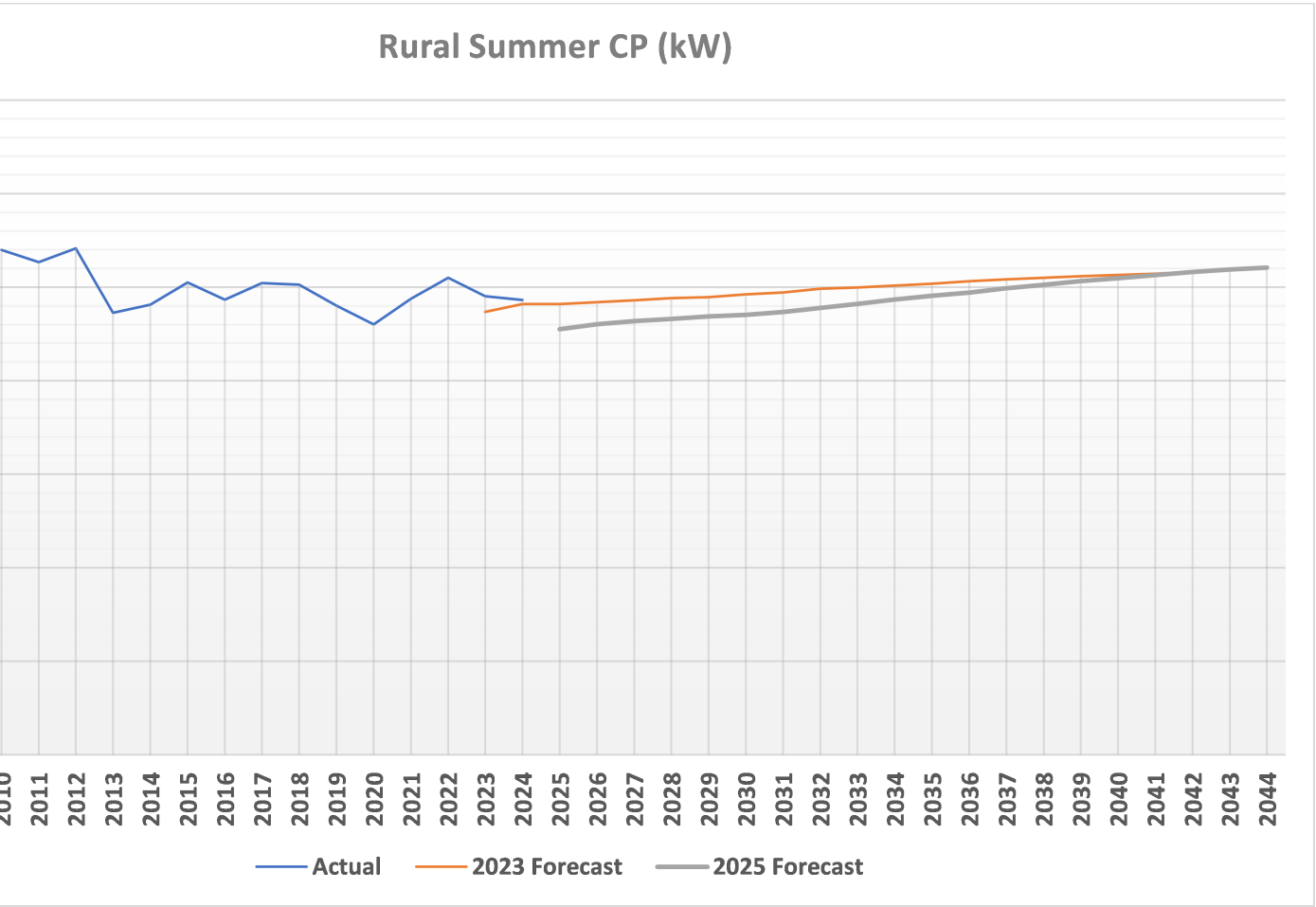


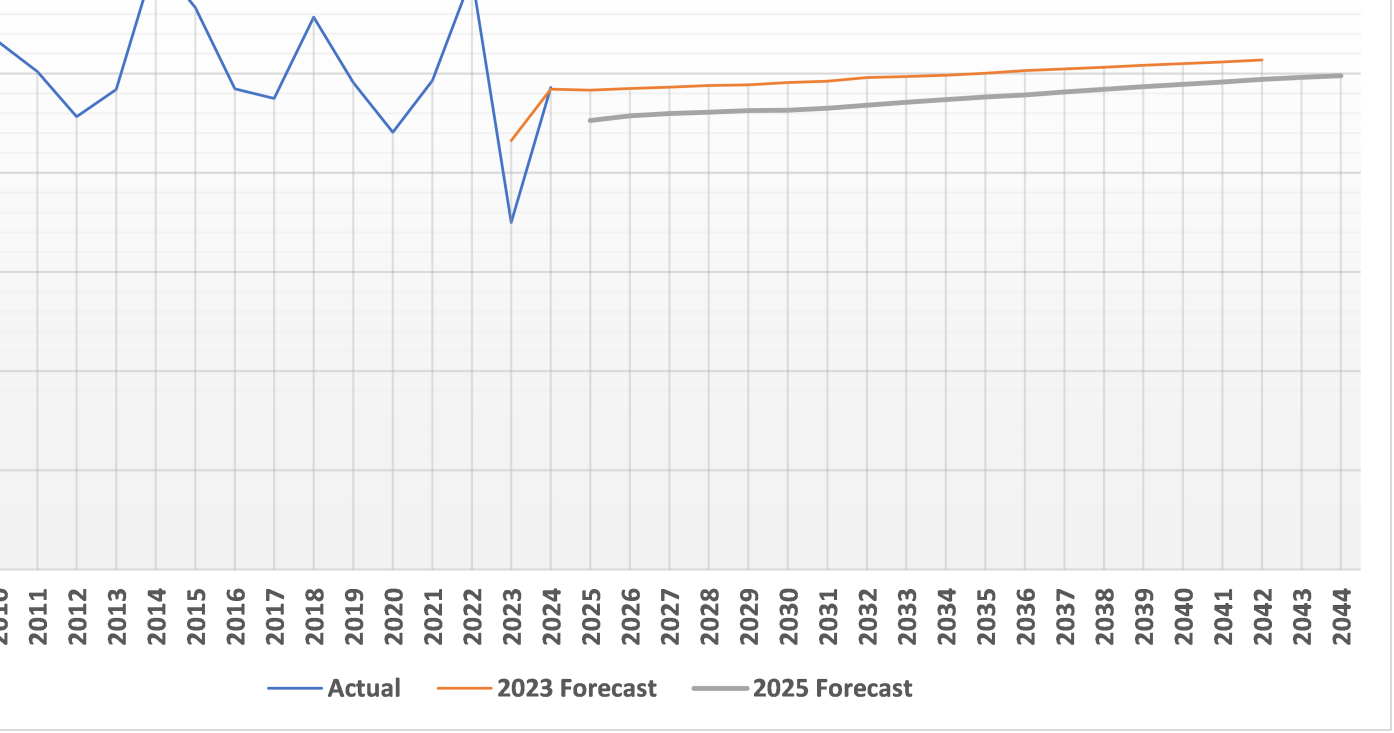
2023 Forecast Rural Energy Requirements Comparison



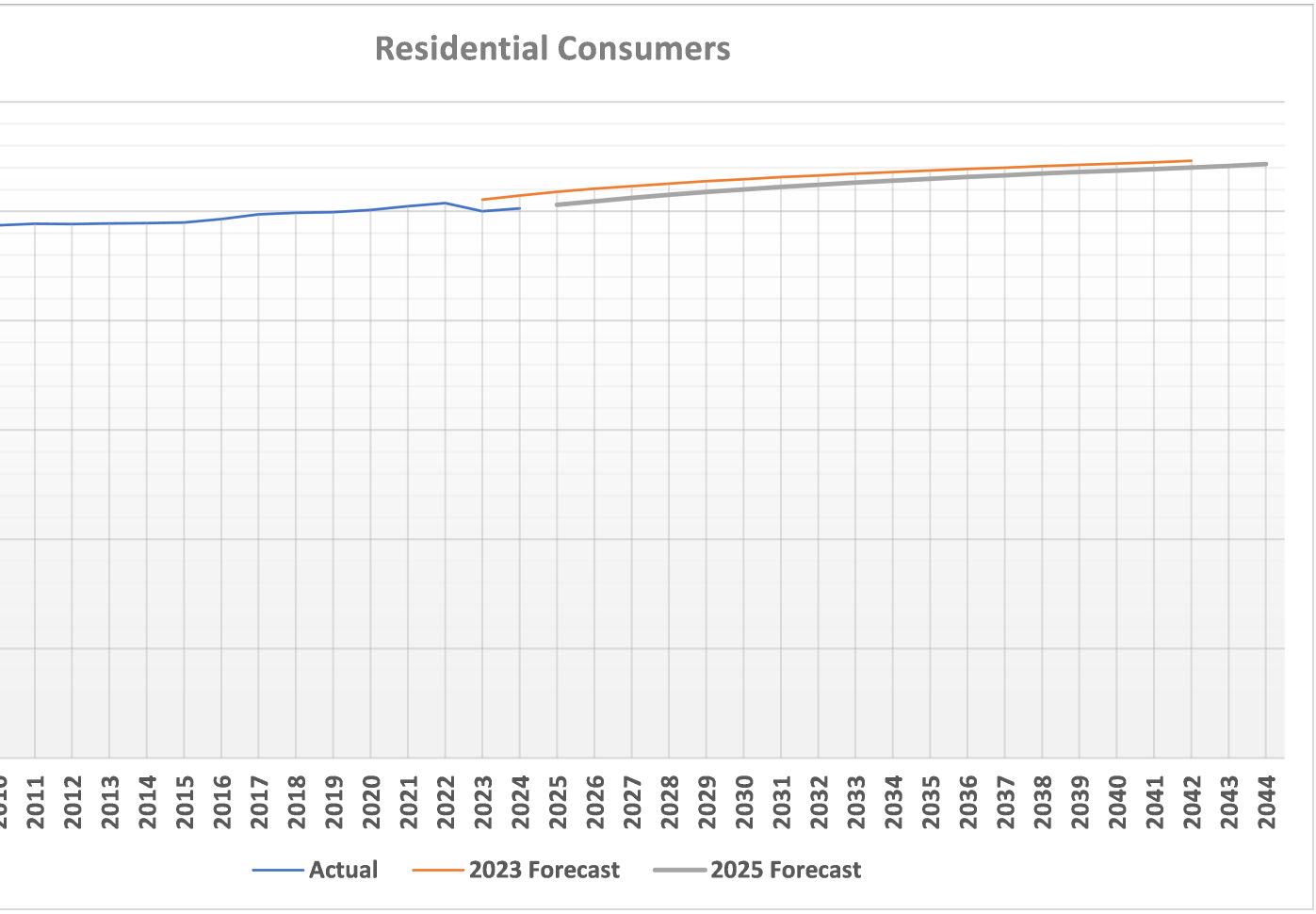


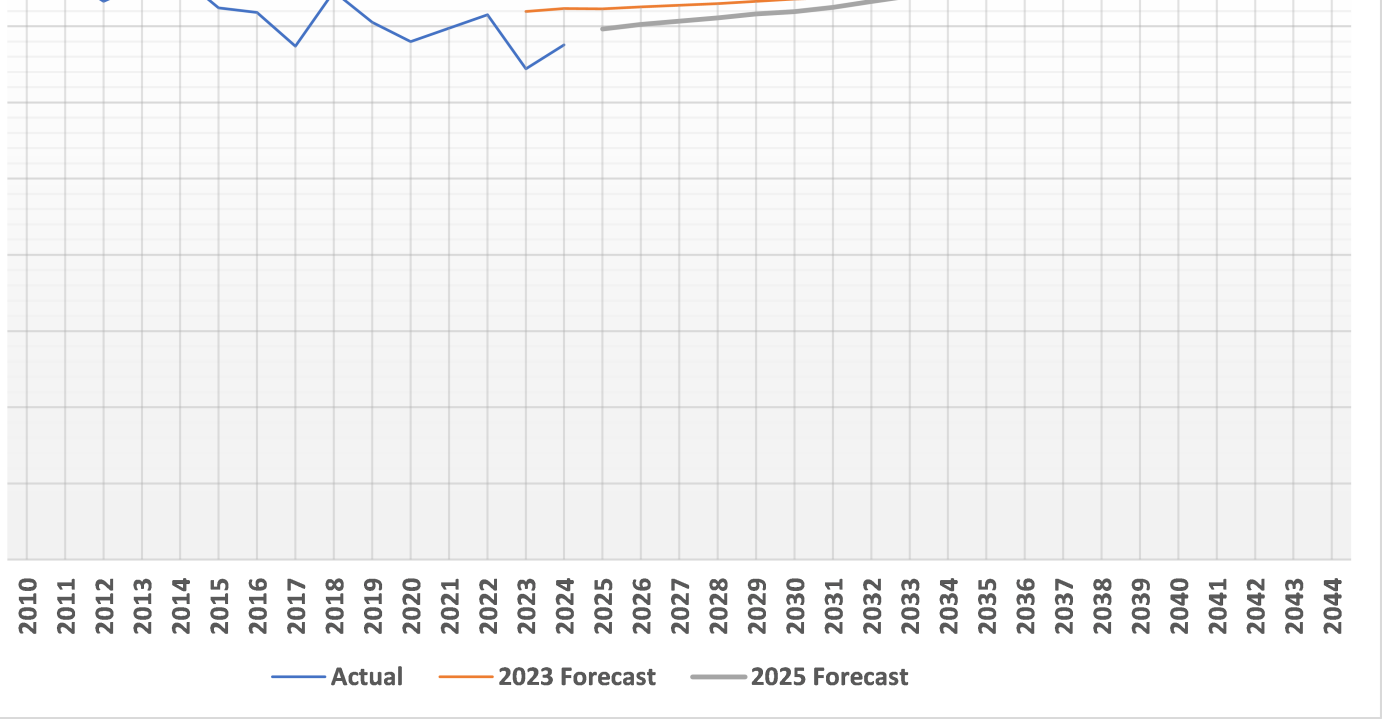
2023 Forecast Rural Summer CP Comparison



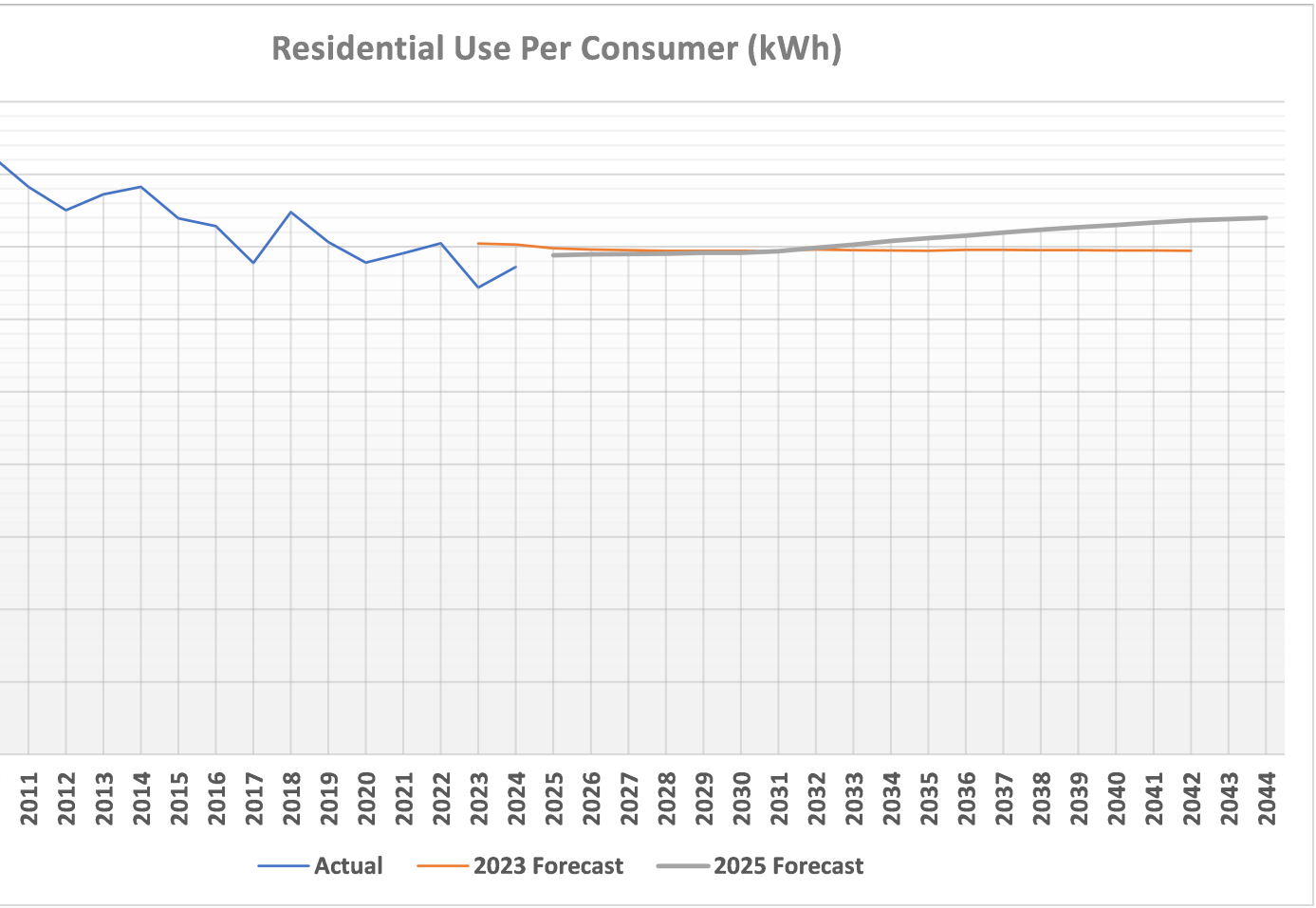


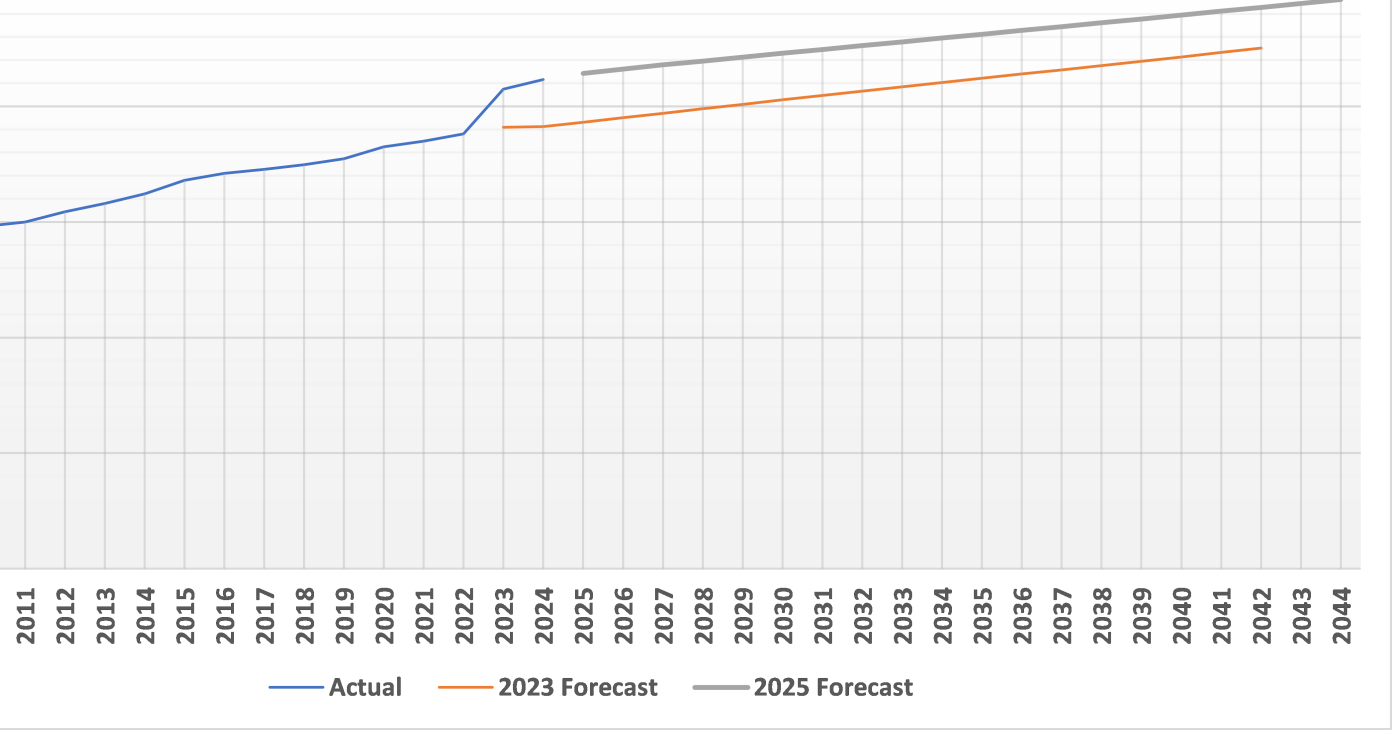
2023 Forecast Residential Consumers Comparison



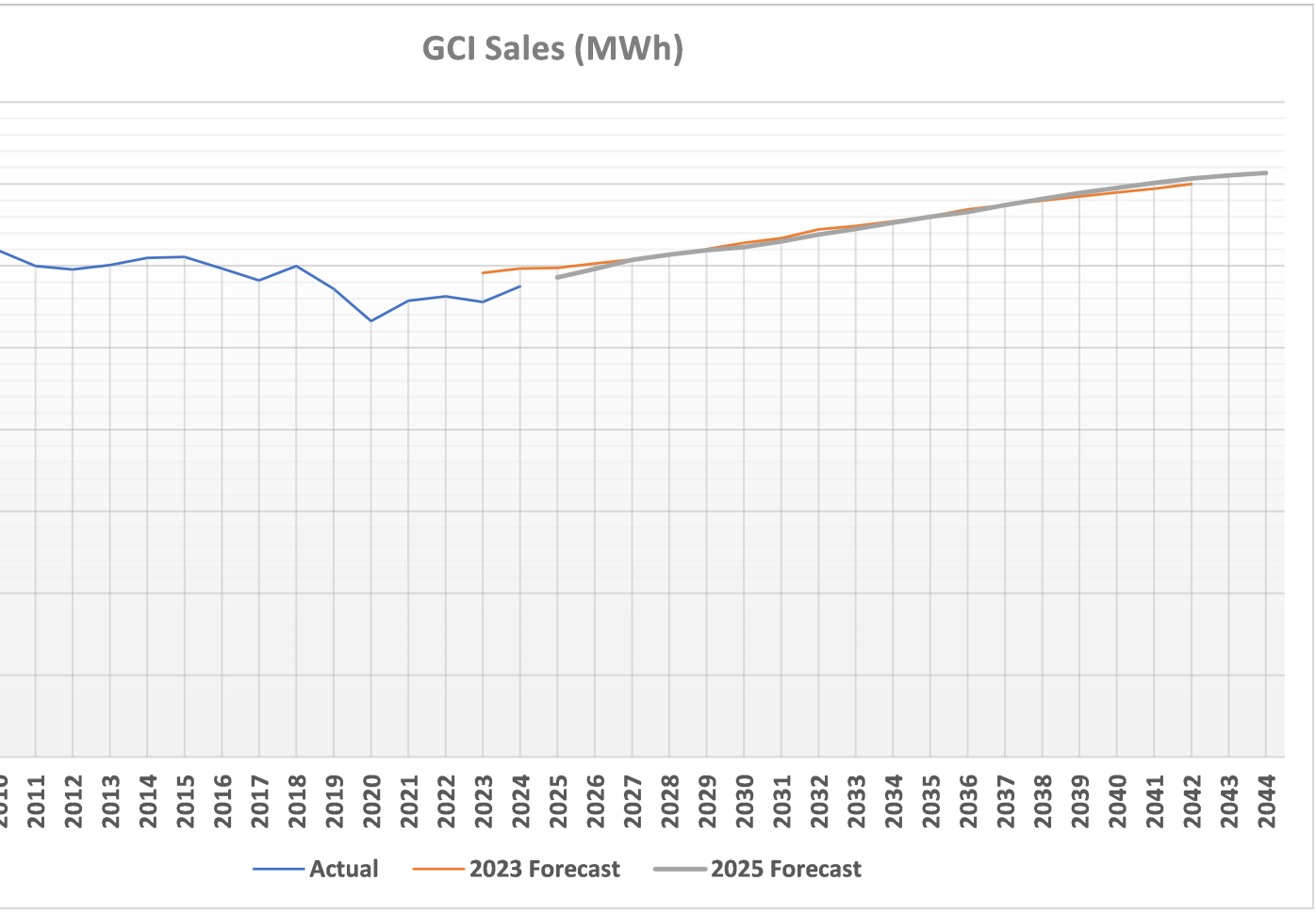


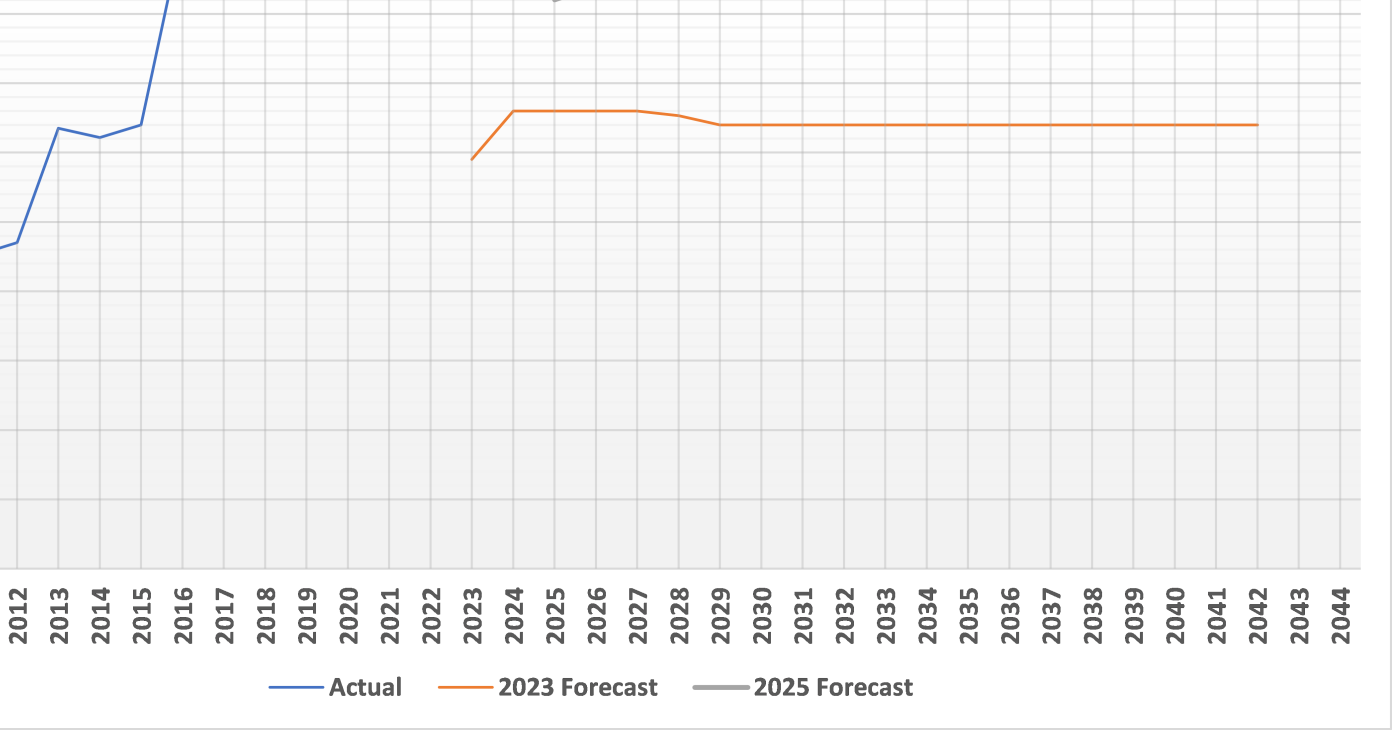
2023 Forecast Residential Use Per Consumer Comparison



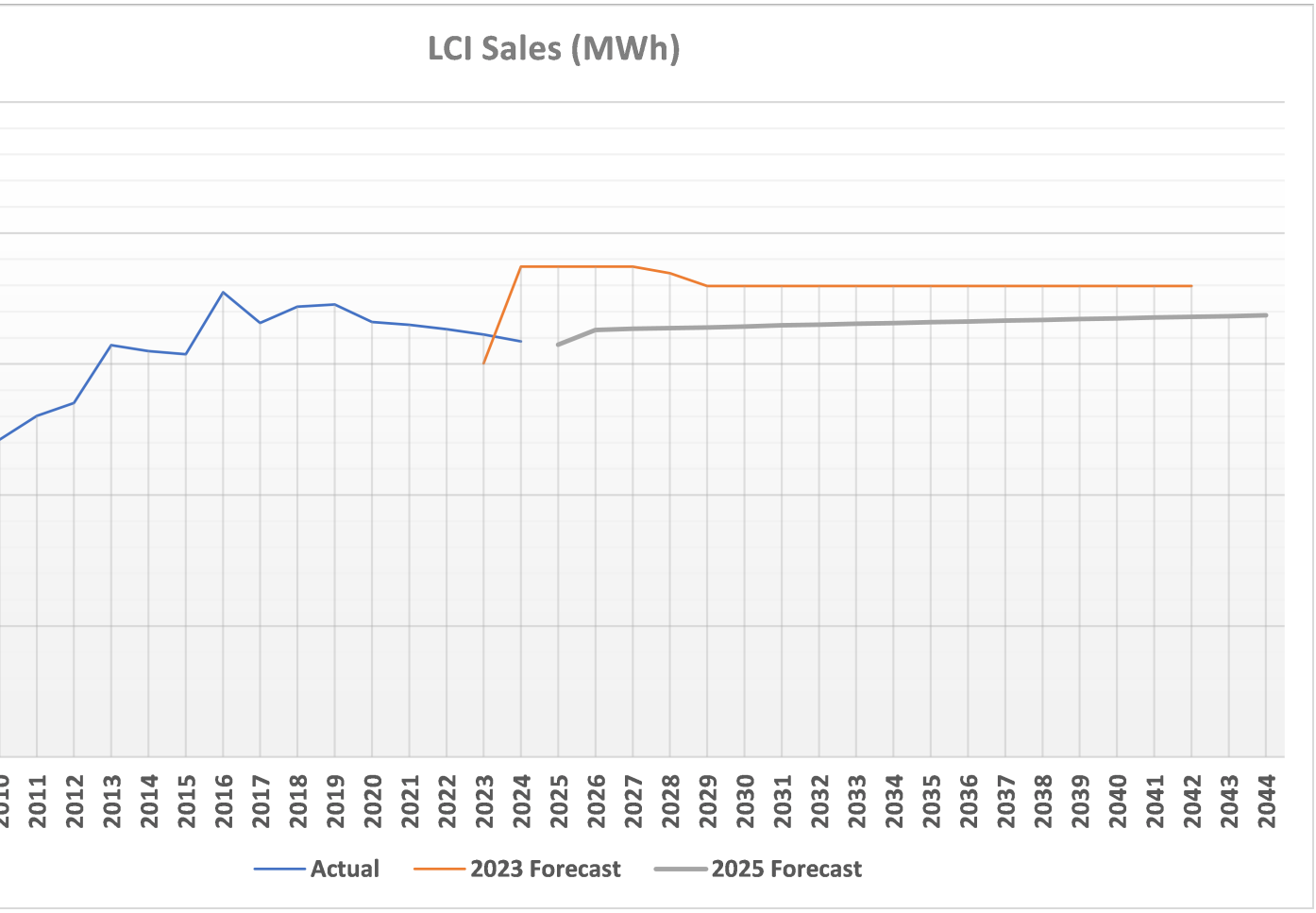


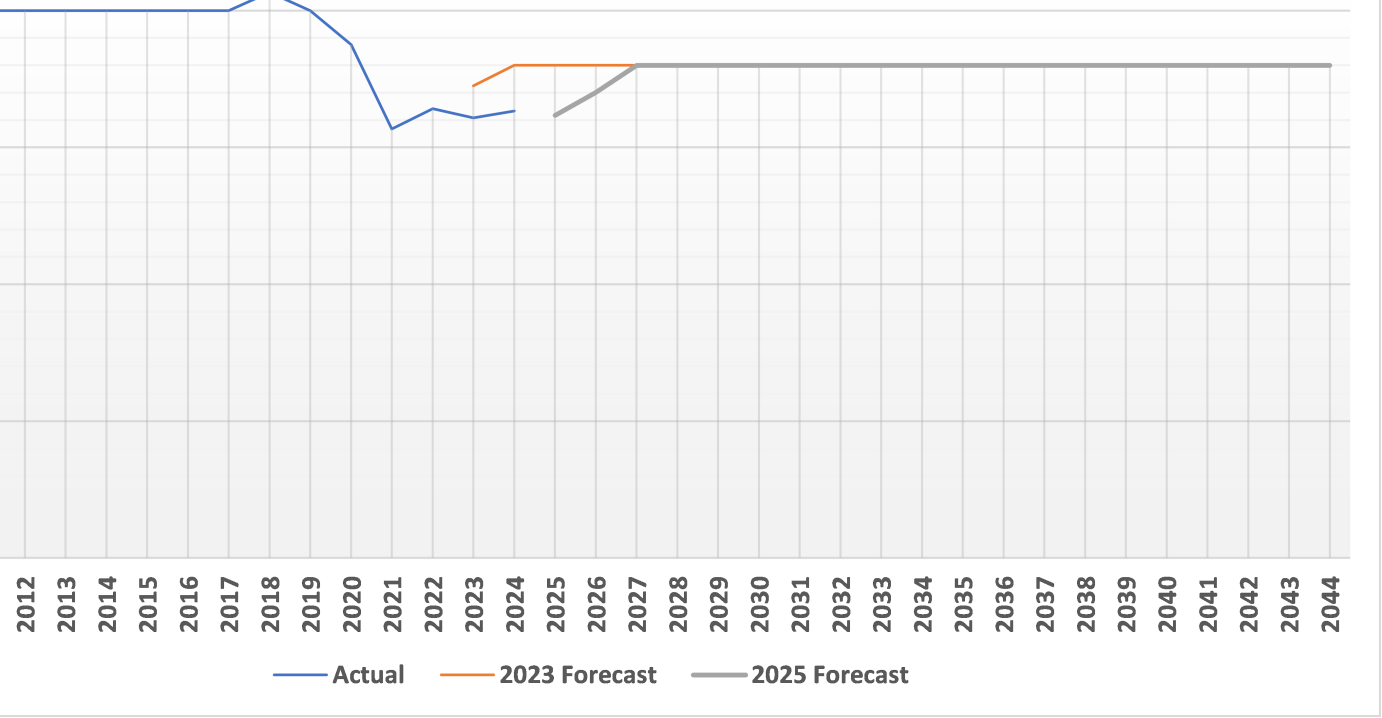
2023 Forecast GCI Sales Comparison



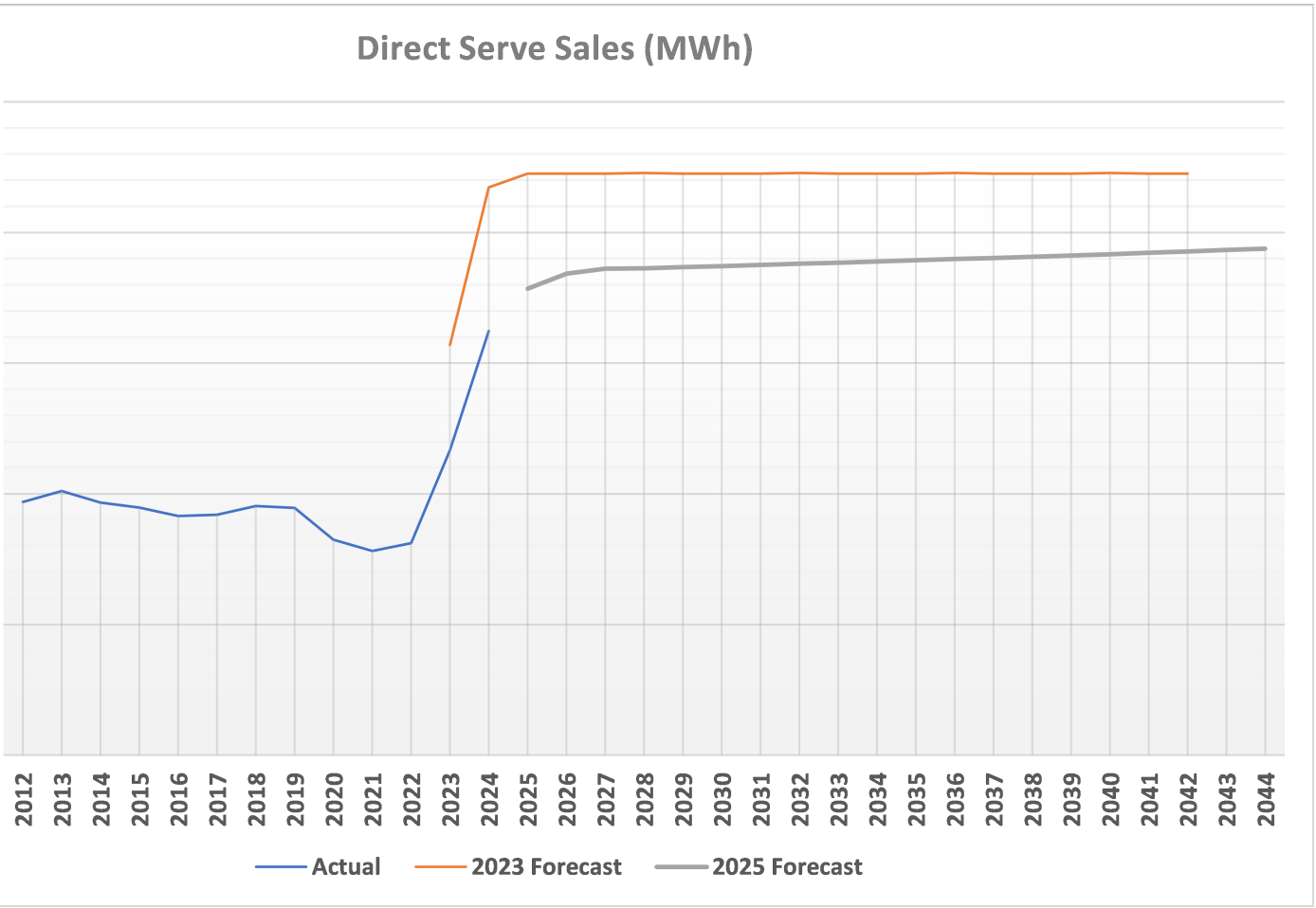


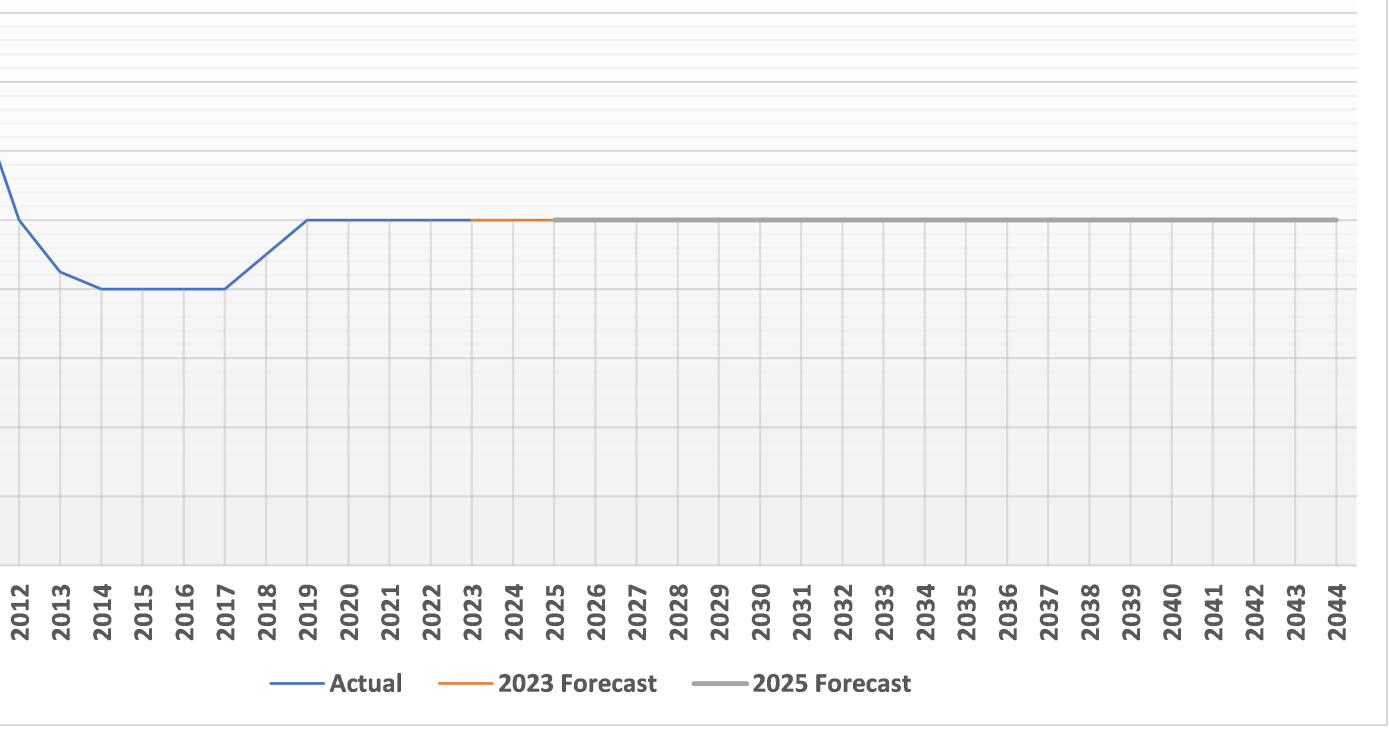
2023 Forecast LCI Sales Comparison



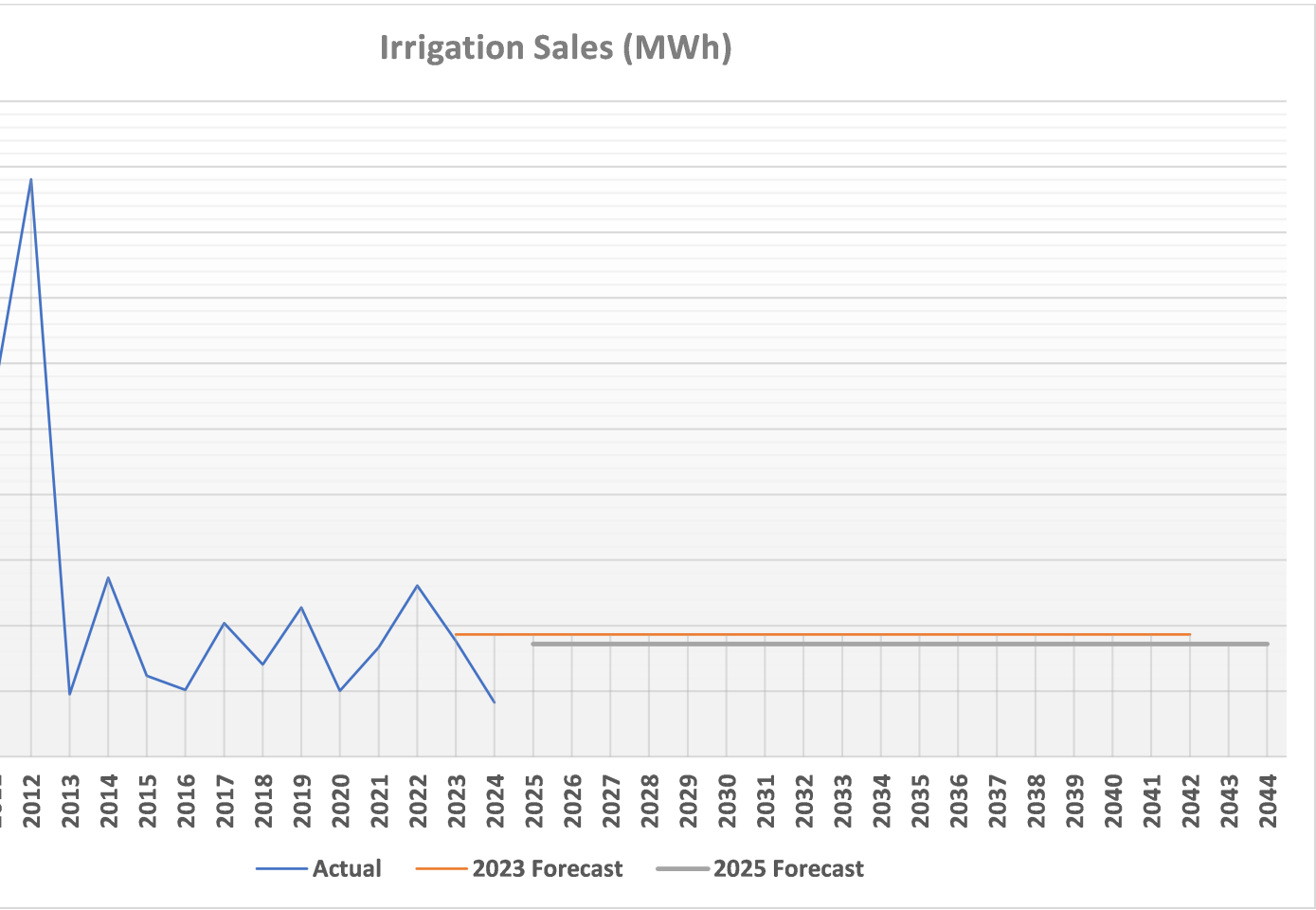


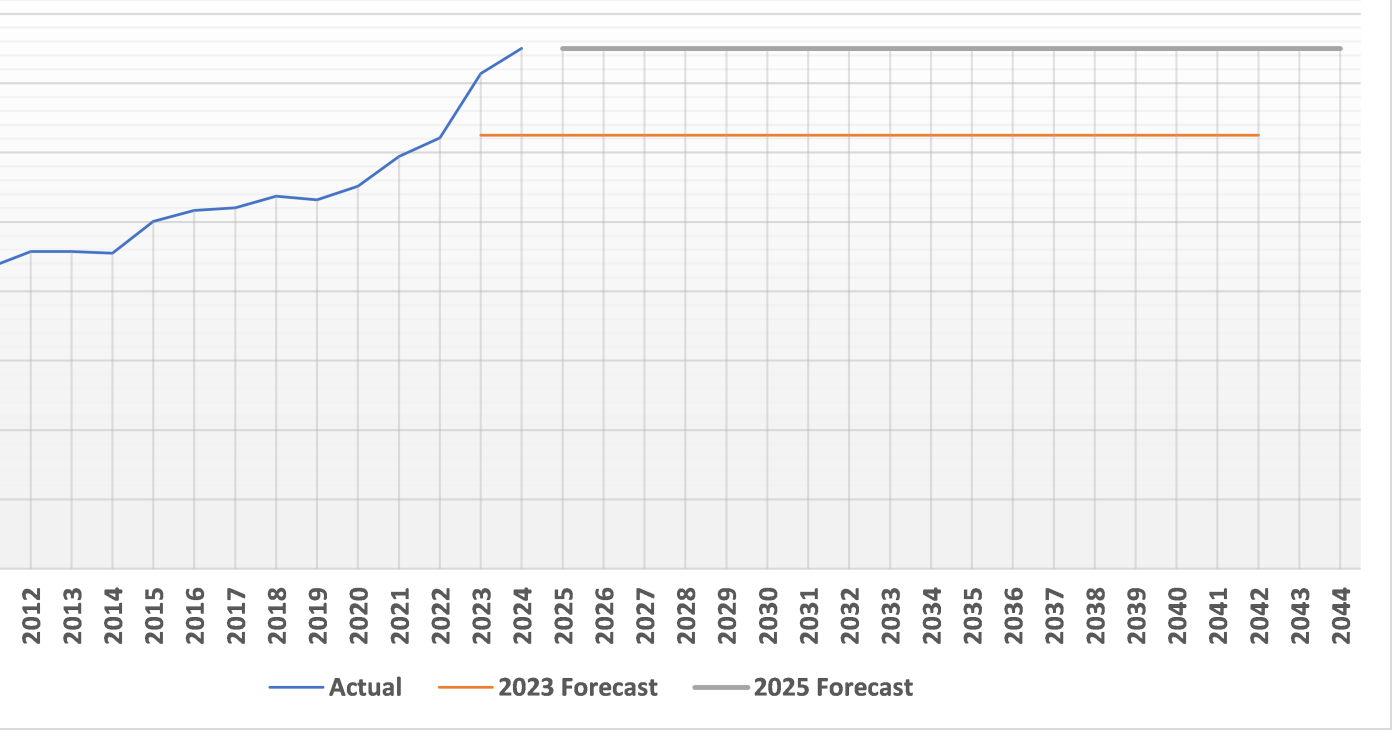
2023 Forecast Direct Serve Sales Comparison



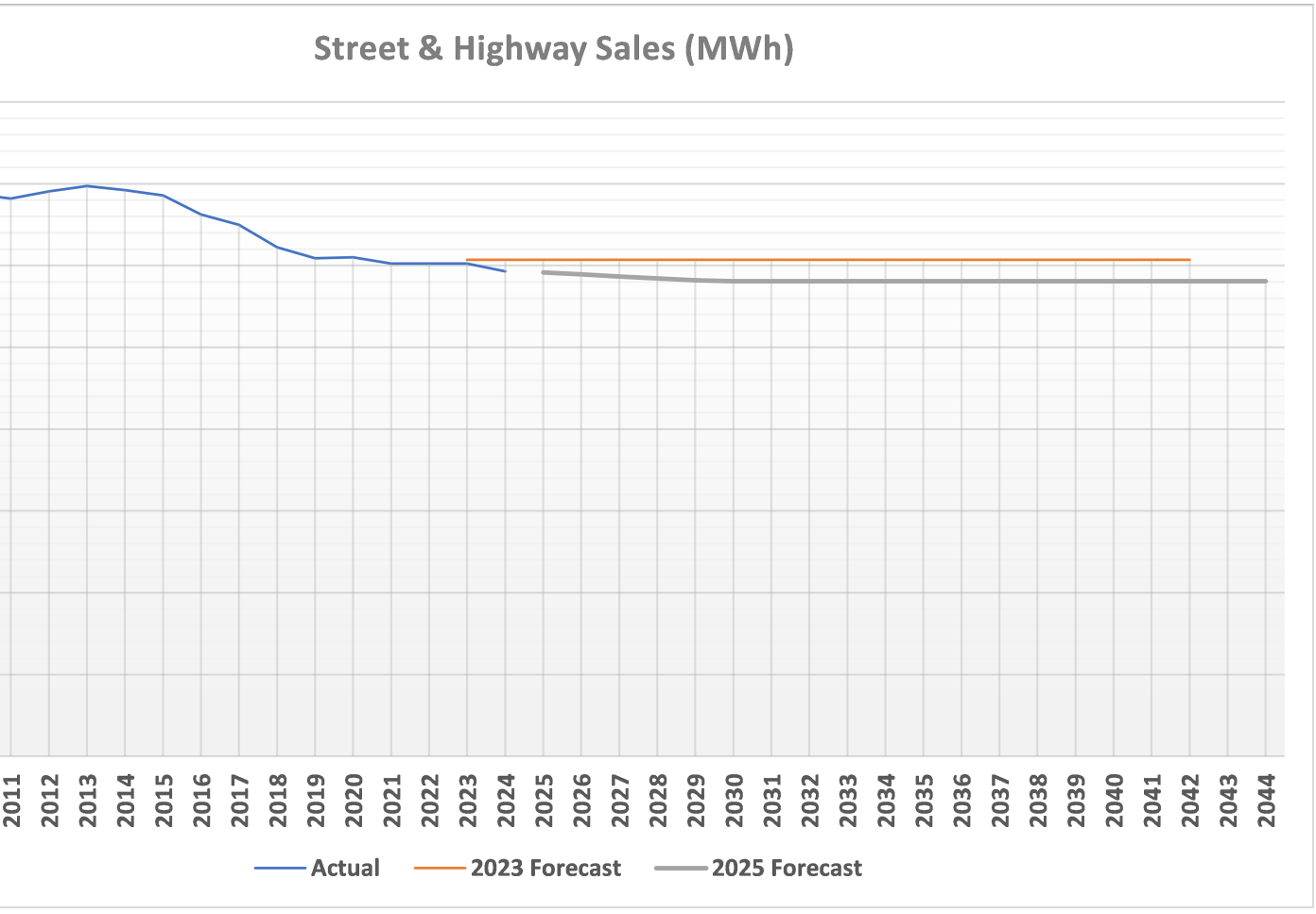


2023 Forecast Irrigation Sales Comparison





2023 Forecast Street & Highway Sales Comparison



10 APPENDIX

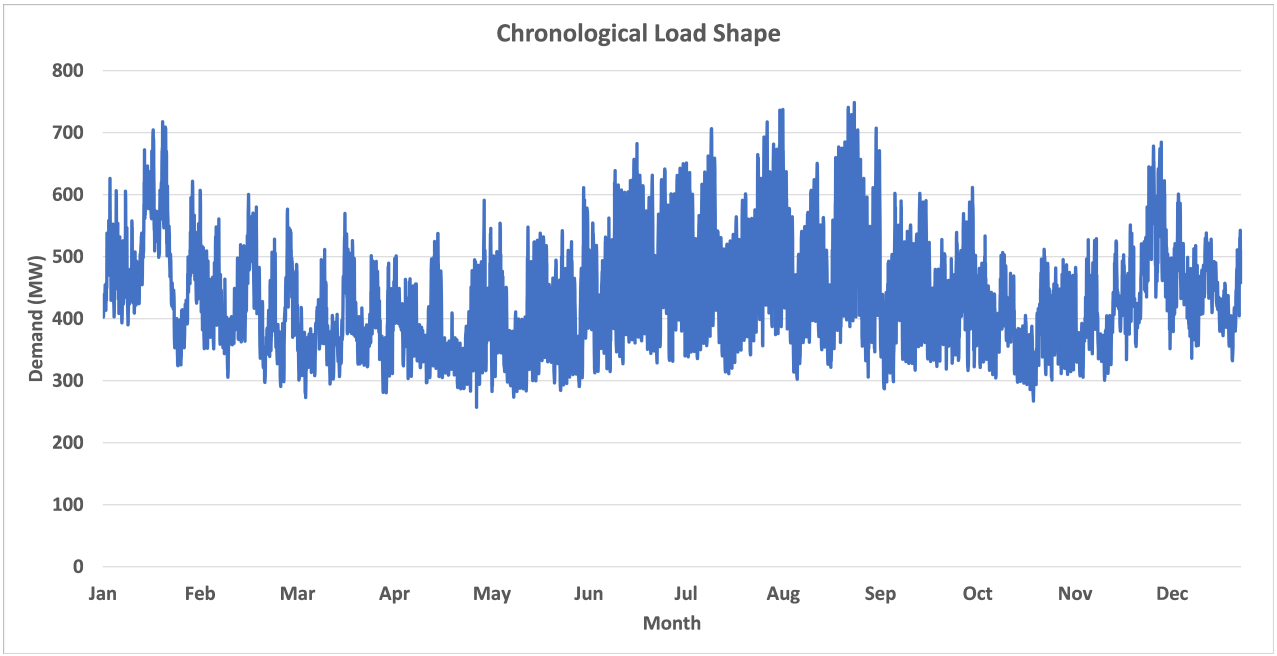
The following table provides the details on the consumers, sales, and use per consumer for each class for the Big Rivers Native system. The prior five years and the forecasted year values are provided in the table. Both historical and forecasted growth rates for each class are also provided.

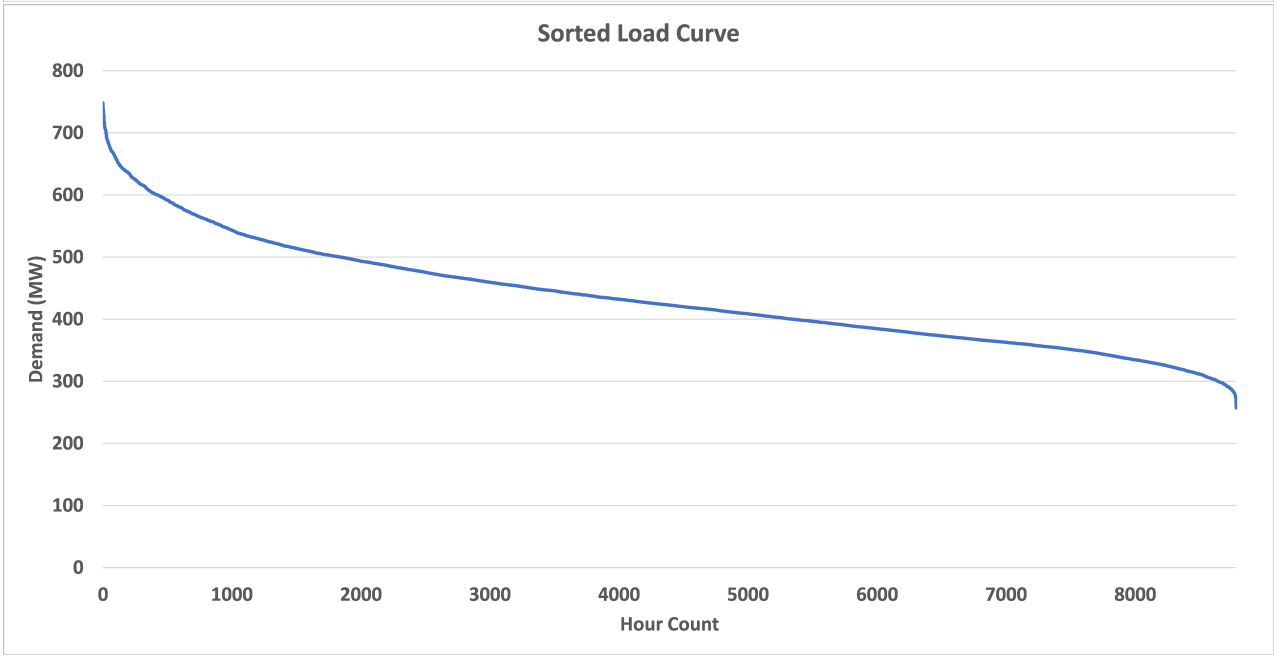
BIG RIVERS ELECTRIC CORPORATION										
RESIDENTIAL	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
CONSUMERS	100,257	100,954	101,506	100,036	100,519	101,190	101,840	102,447	103,017	103,543
SALES-MWH	1,359,904	1,395,391	1,430,495	1,288,283	1,350,807	1,392,722	1,404,711	1,413,702	1,422,226	1,431,945
USE PER CONSUMER-kWH	13,564	13,822	14,093	12,878	13,438	13,763	13,793	13,799	13,806	13,830
GENERAL C&I	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
CONSUMERS	18,249	18,489	18,801	20,736	21,160	21,427	21,611	21,789	21,958	22,126
SALES-MWH	532,524	557,358	562,848	555,946	574,743	585,752	596,143	607,363	613,529	619,214
USE PER CONSUMER-kWH	29,181	30,146	29,936	26,810	27,162	27,338	27,586	27,875	27,941	27,986
LARGE C&I	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
CONSUMERS	44	43	42	43	42	41	42	42	42	42
SALES-MWH	165,984	164,961	163,242	161,296	158,629	157,403	163,044	163,449	163,652	163,999
USE PER CONSUMER-kWH	3,808,425	3,836,298	3,848,539	3,773,005	3,776,887	3,839,104	3,882,006	3,891,642	3,896,473	3,904,736
IRRIGATION	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
CONSUMERS	5	5	5	5	5	5	5	5	5	5
SALES-MWH	50	84	130	88	41	86	86	86	86	86
USE PER CONSUMER-kWH	10,043	16,704	26,082	17,654	8,272	17,178	17,178	17,178	17,178	17,178
STREET & HIGHWAY	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
CONSUMERS	110	119	124	143	150	150	150	150	150	150
SALES-MWH	3,050	3,012	3,011	3,012	2,965	2,957	2,945	2,933	2,921	2,910
USE PER CONSUMER-kWH	27,662	25,332	24,234	21,100	19,764	19,716	19,635	19,555	19,475	19,397
RURAL TOTAL	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
CONSUMERS	118,665	119,609	120,479	120,963	121,876	122,812	123,647	124,433	125,171	125,865
SALES-MWH	2,061,512	2,120,806	2,159,727	2,008,625	2,087,185	2,138,920	2,166,930	2,187,533	2,202,414	2,218,153
USE PER CONSUMER-kWH	17,373	17,731	17,926	16,605	17,126	17,416	17,525	17,580	17,595	17,623
OWNUSE-MWH	2,814	3,666	4,103	3,893	3,836	3,997	4,023	4,047	4,069	4,090
PURCHASES-MWH	2,164,868	2,219,380	2,269,586	2,097,660	2,179,785	2,238,259	2,267,529	2,285,503	2,301,046	2,317,481
LOSSES-MWH	100,542	94,909	105,756	85,141	88,764	95,343	96,577	93,924	94,562	95,238
LOSSES (%)	4.6%	4.3%	4.7%	4.1%	4.1%	4.3%	4.3%	4.1%	4.1%	4.1%
DIRECT SERVE	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
CONSUMERS	19	16	16	16	16	16	17	18	18	18
SALES-MWH	824,695	781,559	811,577	1,167,083	1,623,201	1,785,062	1,842,767	1,861,031	1,863,066	1,867,091
USE PER CONSUMER-kWH	43,983,732	49,886,728	49,436,162	72,564,762	99,379,680	110,416,182	108,398,077	103,390,618	103,503,639	103,727,255
SYSTEM TOTAL WITH DIRECT SERVE	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
CONSUMERS	118,684	119,625	120,496	120,979	121,892	122,829	123,664	124,451	125,189	125,883
SALES-MWH	2,886,207	2,902,364	2,971,304	3,175,708	3,710,387	3,923,982	4,009,697	4,048,564	4,065,480	4,085,244
USE PER CONSUMER-kWH	24,318	24,262	24,659	26,250	30,440	31,947	32,424	32,531	32,475	32,453
OWNUSE-MWH	2,814	3,666	4,103	3,893	3,836	3,997	4,023	4,047	4,069	4,090
AUX. SALES-MWH	16,944	18,367	6,184	833	935	935	935	935	935	935
TOTAL ENERGY REQUIREMENTS-MWH (NO TRANSMISSION LOSSES)	3,006,507	3,019,306	3,087,347	3,265,575	3,803,921	4,024,256	4,111,231	4,147,469	4,165,046	4,185,506
DISTRIBUTION LOSSES-MWH	100,542	94,909	105,756	85,141	88,764	95,343	96,577	93,924	94,562	95,238
DISTRIBUTION LOSS (%)	3.3%	3.1%	3.4%	2.6%	2.3%	2.4%	2.3%	2.3%	2.3%	2.3%
TRANSMISSION LOSSES-MWH	77,120	71,125	72,325	78,103	93,173	100,594	102,768	103,674	104,114	104,625
TRANSMISSION LOSS (%)	2.5%	2.3%	2.3%	2.3%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%
TOTAL ENERGY REQUIREMENTS-MWH	3,083,627	3,090,431	3,159,672	3,343,678	3,897,094	4,124,850	4,213,999	4,251,143	4,269,159	4,290,131
DEMAND RESPONSE (DR)- MWH	0	0	0	9	1,559	1,695	2,404	2,905	2,905	2,905
TOTAL ENERGY REQ. WITHOUT DR-(NO TX LOSSES) MWH	3,006,507	3,019,306	3,087,347	3,265,584	3,805,480	4,025,950	4,113,635	4,158,374	4,167,951	4,188,412
ANNUAL PEAK	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
RURAL CP - kW	460,173	492,854	598,264	490,432	486,295	455,173	460,529	463,671	466,205	468,897
DIRECT SERVE CP - kW	105,992	96,513	88,521	225,419	262,165	267,211	273,399	276,079	276,577	277,371
AUX CP - kW	1,756	3,046	248	99	104	143	143	143	143	143
TOTAL CP - kW (NO TRANSMISSION LOSSES)	567,921	592,413	687,033	715,951	748,564	722,526	734,070	739,893	742,925	746,410
TRANSMISSION LOSSES - kW	14,562	13,822	16,102	17,155	18,378	18,061	18,350	18,495	18,571	18,658
TRANSMISSION LOSS (%)	2.5%	2.3%	2.3%	2.3%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%
TOTAL CP - kW (WITH TRANSMISSION LOSSES)	582,483	606,235	703,135	733,105	766,942	740,587	752,420	758,388	761,496	765,068
DEMAND RESPONSE (DR)- kW	0	0	0	0	0	1,270	2,177	2,177	2,177	2,177
TOTAL CP - kW WITHOUT DR (NO TX LOSSES)	567,921	592,413	687,033	715,951	748,564	723,796	736,247	742,070	745,102	748,587

BIG RIVERS ELECTRIC CORPORATION										
RESIDENTIAL	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
CONSUMERS	104,029	104,472	104,880	105,257	105,617	105,961	106,289	106,601	106,899	107,186
SALES-MWH	1,438,795	1,449,666	1,464,987	1,479,925	1,495,172	1,508,848	1,520,241	1,534,344	1,546,517	1,558,494
USE PER CONSUMER-kWH	13,831	13,876	13,968	14,060	14,157	14,240	14,303	14,393	14,467	14,540
GENERAL C&I	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
CONSUMERS	22,292	22,458	22,622	22,786	22,951	23,115	23,280	23,446	23,612	23,777
SALES-MWH	622,721	629,899	638,083	644,916	652,709	659,787	665,607	674,142	681,690	689,111
USE PER CONSUMER-kWH	27,934	28,048	28,206	28,303	28,440	28,543	28,591	28,753	28,871	28,982
LARGE C&I	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
CONSUMERS	42	42	42	42	42	42	42	42	42	42
SALES-MWH	164,352	164,727	165,064	165,355	165,652	165,926	166,206	166,526	166,845	167,129
USE PER CONSUMER-kWH	3,913,145	3,922,062	3,930,095	3,937,014	3,944,090	3,950,623	3,957,275	3,964,908	3,972,489	3,979,266
IRRIGATION	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
CONSUMERS	5	5	5	5	5	5	5	5	5	5
SALES-MWH	86	86	86	86	86	86	86	86	86	86
USE PER CONSUMER-kWH	17,178	17,178	17,178	17,178	17,178	17,178	17,178	17,178	17,178	17,178
STREET & HIGHWAY	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
CONSUMERS	150	150	150	150	150	150	150	150	150	150
SALES-MWH	2,904	2,904	2,904	2,904	2,904	2,904	2,904	2,904	2,904	2,904
USE PER CONSUMER-kWH	19,361	19,361	19,361	19,361	19,361	19,361	19,361	19,361	19,361	19,361
RURAL TOTAL	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
CONSUMERS	126,518	127,127	127,699	128,240	128,764	129,274	129,766	130,243	130,707	131,161
SALES-MWH	2,228,858	2,247,281	2,271,125	2,293,186	2,316,523	2,337,551	2,355,044	2,378,002	2,398,041	2,417,725
USE PER CONSUMER-kWH	17,617	17,677	17,785	17,882	17,990	18,082	18,148	18,258	18,347	18,433
OWNUSE-MWH	4,109	4,126	4,142	4,157	4,171	4,184	4,197	4,209	4,221	4,232
PURCHASES-MWH	2,328,667	2,347,896	2,372,775	2,395,795	2,420,143	2,442,083	2,460,336	2,484,286	2,505,191	2,525,724
LOSSES-MWH	95,700	96,489	97,508	98,452	99,449	100,347	101,095	102,075	102,929	103,768
LOSSES (%)	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%
DIRECT SERVE	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
CONSUMERS	18	18	18	18	18	18	18	18	18	18
SALES-MWH	1,871,556	1,876,179	1,880,236	1,884,854	1,888,897	1,893,375	1,898,249	1,902,702	1,907,552	1,912,320
USE PER CONSUMER-kWH	103,975,354	104,232,193	104,457,546	104,714,137	104,938,732	105,187,472	105,458,260	105,705,680	105,975,886	106,239,994
SYSTEM TOTAL WITH DIRECT SERVE	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
CONSUMERS	126,536	127,145	127,717	128,258	128,782	129,292	129,784	130,261	130,725	131,179
SALES-MWH	4,100,415	4,123,461	4,151,361	4,178,040	4,205,420	4,230,926	4,253,293	4,280,704	4,305,593	4,330,044
USE PER CONSUMER-kWH	32,405	32,431	32,504	32,575	32,655	32,724	32,772	32,862	32,936	33,009
OWNUSE-MWH	4,109	4,126	4,142	4,157	4,171	4,184	4,197	4,209	4,221	4,232
AUX. SALES-MWH	935	935	935	935	935	935	935	935	935	935
TOTAL ENERGY REQUIREMENTS-MWH (NO TRANSMISSION LOSSES)	4,201,158	4,225,011	4,253,946	4,281,584	4,309,975	4,336,393	4,359,520	4,387,923	4,413,677	4,438,979
DISTRIBUTION LOSSES-MWH	95,700	96,489	97,508	98,452	99,449	100,347	101,095	102,075	102,929	103,768
DISTRIBUTION LOSS (%)	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%
TRANSMISSION LOSSES-MWH	105,016	105,613	106,336	107,027	107,736	108,397	108,975	109,685	110,329	110,961
TRANSMISSION LOSS (%)	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%
TOTAL ENERGY REQUIREMENTS-MWH	**4,306,175**	**4,330,623**	**4,360,282**	**4,388,610**	**4,417,711**	**4,444,789**	**4,468,495**	**4,497,607**	**4,524,606**	**4,549,940**
DEMAND RESPONSE (DR)- MWH	2,905	2,905	2,905	2,905	2,905	2,905	2,905	2,905	2,905	2,905
TOTAL ENERGY REQ. WITHOUT DR-(NO TX LOSSES) MWH	**4,294,864**	**4,327,916**	**4,256,851**	**4,294,489**	**4,312,888**	**4,339,298**	**4,362,425**	**4,398,828**	**4,416,583**	**4,441,884**
ANNUAL PEAK	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
RURAL CP - kW	470,437	473,604	477,854	482,140	486,736	490,833	494,175	498,687	502,587	506,430
DIRECT SERVE CP - kW	278,240	279,118	279,921	280,842	281,648	282,536	283,502	284,392	285,362	286,321
AUX CP - kW	143	143	143	143	143	143	143	143	143	143
TOTAL CP - kW (NO TRANSMISSION LOSSES)	748,820	752,864	757,918	763,124	768,526	773,512	777,819	783,221	788,091	792,893
TRANSMISSION LOSSES - kW	18,718	18,819	18,946	19,076	19,211	19,335	19,443	19,578	19,700	19,820
TRANSMISSION LOSS (%)	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%
TOTAL CP - kW (WITH TRANSMISSION LOSSES)	**767,538**	**771,684**	**776,863**	**782,200**	**787,737**	**792,847**	**797,262**	**802,800**	**807,791**	**812,713**
DEMAND RESPONSE (DR)- kW	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177
TOTAL CP - kW WITHOUT DR (NO TX LOSSES)	**758,997**	**755,041**	**760,095**	**765,301**	**778,704**	**775,689**	**779,996**	**785,398**	**790,268**	**795,070**

BIG RIVERS ELECTRIC CORPORATION						Last 10 Yrs	Last 5 Yrs	Next 5 Yrs	Next 10 Yrs	Next 20 Yrs
RESIDENTIAL	2040	2041	2042	2043	2044	2014 - 2024	2019 - 2024	2024 - 2029	2024 - 2034	2024 - 2044
CONSUMERS	107,464	107,740	108,025	108,326	108,641	0.3%	0.1%	0.6%	0.5%	0.4%
SALES-MWH	1,568,848	1,579,824	1,590,539	1,599,590	1,607,585	-1.2%	-0.9%	1.2%	1.0%	0.9%
USE PER CONSUMER-kWH	14,599	14,663	14,724	14,766	14,797	-1.5%	-1.0%	0.6%	0.5%	0.5%
GENERAL C&I	2040	2041	2042	2043	2044	2014 - 2024	2019 - 2024	2024 - 2029	2024 - 2034	2024 - 2044
CONSUMERS	23,944	24,112	24,281	24,452	24,625	2.7%	3.6%	0.9%	0.8%	0.8%
SALES-MWH	695,002	701,002	706,484	710,218	713,436	-0.6%	0.1%	1.5%	1.3%	1.1%
USE PER CONSUMER-kWH	29,026	29,073	29,096	29,045	28,972	-3.2%	-3.4%	0.6%	0.5%	0.3%
LARGE C&I	2040	2041	2042	2043	2044	2014 - 2024	2019 - 2024	2024 - 2029	2024 - 2034	2024 - 2044
CONSUMERS	42	42	42	42	42	3.1%	-1.0%	0.0%	0.0%	0.0%
SALES-MWH	167,420	167,730	168,020	168,304	168,560	0.2%	-1.7%	0.7%	0.4%	0.3%
USE PER CONSUMER-kWH	3,986,195	3,993,563	4,000,487	4,007,238	4,013,334	-2.7%	-0.7%	0.7%	0.4%	0.3%
IRRIGATION	2040	2041	2042	2043	2044	2014 - 2024	2019 - 2024	2024 - 2029	2024 - 2034	2024 - 2044
CONSUMERS	5	5	5	5	5	2.3%	0.0%	0.0%	0.0%	0.0%
SALES-MWH	86	86	86	86	86	-11.3%	-18.3%	15.7%	7.6%	3.7%
USE PER CONSUMER-kWH	17,178	17,178	17,178	17,178	17,178	-13.2%	-18.3%	15.7%	7.6%	3.7%
STREET & HIGHWAY	2040	2041	2042	2043	2044	2014 - 2024	2019 - 2024	2024 - 2029	2024 - 2034	2024 - 2044
CONSUMERS	150	150	150	150	150	5.1%	7.1%	0.0%	0.0%	0.0%
SALES-MWH	2,904	2,904	2,904	2,904	2,904	-1.5%	-0.5%	-0.4%	-0.2%	-0.1%
USE PER CONSUMER-kWH	19,361	19,361	19,361	19,361	19,361	-6.3%	-7.2%	-0.4%	-0.2%	-0.1%
RURAL TOTAL	2040	2041	2042	2043	2044	2014 - 2024	2019 - 2024	2024 - 2029	2024 - 2034	2024 - 2044
CONSUMERS	131,606	132,049	132,503	132,975	133,463	0.7%	0.7%	0.6%	0.6%	0.5%
SALES-MWH	2,434,260	2,451,546	2,468,033	2,481,102	2,492,571	-1.0%	-0.7%	1.2%	1.0%	0.9%
USE PER CONSUMER-kWH	18,497	18,565	18,626	18,658	18,676	-1.6%	-1.3%	0.6%	0.5%	0.4%
OWNUSE-MWH	4,242	4,253	4,264	4,275	4,287	13.5%	4.4%	1.3%	0.8%	0.6%
PURCHASES-MWH	2,542,976	2,561,009	2,578,209	2,591,846	2,603,815	-1.0%	-0.7%	1.2%	1.1%	0.9%
LOSSES-MWH	104,473	105,209	105,912	106,469	106,957	-2.5%	-2.3%	1.4%	1.1%	0.9%
LOSSES (%)	4.1%	4.1%	4.1%	4.1%	4.1%	-1.5%	-1.6%	0.2%	0.1%	0.0%
DIRECT SERVE	2040	2041	2042	2043	2044	2014 - 2024	2019 - 2024	2024 - 2029	2024 - 2034	2024 - 2044
CONSUMERS	18	18	18	18	18	-2.0%	-4.0%	2.0%	1.0%	0.5%
SALES-MWH	1,917,144	1,922,446	1,927,690	1,932,939	1,938,625	5.3%	11.4%	2.8%	1.5%	0.9%
USE PER CONSUMER-kWH	106,507,996	106,802,545	107,093,902	107,385,491	107,701,397	7.5%	16.0%	0.9%	0.5%	0.4%
SYSTEM TOTAL WITH DIRECT SERVE	2040	2041	2042	2043	2044	2014 - 2024	2019 - 2024	2024 - 2029	2024 - 2034	2024 - 2044
CONSUMERS	131,624	132,067	132,521	132,993	133,481	0.7%	0.7%	0.6%	0.6%	0.5%
SALES-MWH	4,351,404	4,373,992	4,395,724	4,414,041	4,431,196	1.3%	3.6%	1.9%	1.3%	0.9%
USE PER CONSUMER-kWH	33,059	33,120	33,179	33,190	33,197	0.6%	2.9%	1.3%	0.7%	0.4%
OWNUSE-MWH	4,242	4,253	4,264	4,275	4,287	13.5%	4.4%	1.3%	0.8%	0.6%
AUX SALES-MWH	935	935	935	935	935	-	-26.8%	0.0%	0.0%	0.0%
TOTAL ENERGY REQUIREMENTS-MWH (NO TRANSMISSION LOSSES)	4,461,054	4,484,389	4,506,834	4,525,719	4,543,375	1.2%	3.4%	1.9%	1.3%	0.9%
DISTRIBUTION LOSSES-MWH	104,473	105,209	105,912	106,469	106,957	-2.5%	-2.3%	1.4%	1.1%	0.9%
DISTRIBUTION LOSS (%)	2.3%	2.3%	2.4%	2.4%	2.4%	-3.6%	-5.5%	-0.5%	-0.1%	0.0%
TRANSMISSION LOSSES-MWH	111,513	112,096	112,657	113,129	113,571	5.5%	2.4%	2.3%	1.5%	1.0%
TRANSMISSION LOSS (%)	2.4%	2.4%	2.4%	2.4%	2.4%	4.2%	-1.0%	0.4%	0.2%	0.1%
TOTAL ENERGY REQUIREMENTS-MWH	4,572,567	4,596,485	4,619,491	4,638,848	4,656,946	1.3%	3.4%	1.9%	1.3%	0.9%
DEMAND RESPONSE (DR)- MWH	2,905	2,905	2,905	2,905	2,905	-	-	13.3%	6.4%	3.2%
TOTAL ENERGY REQ. WITHOUT DR-(NO TX LOSSES) MWH	4,463,959	4,487,294	4,509,739	4,528,624	4,546,288	1.2%	3.5%	1.9%	1.3%	0.9%
ANNUAL PEAK	2040	2041	2042	2043	2044	2014 - 2024	2019 - 2024	2024 - 2029	2024 - 2034	2024 - 2044
RURAL CP - kW	509,638	513,011	516,244	518,799	521,068	-2.3%	-0.2%	-0.7%	0.0%	0.3%
DIRECT SERVE CP - kW	287,290	288,352	289,407	290,465	291,604	7.8%	17.3%	1.1%	0.7%	0.5%
AUX CP - kW	143	143	143	143	143	-	-	6.6%	3.2%	1.6%
TOTAL CP - kW (NO TRANSMISSION LOSSES)	797,070	801,506	805,794	809,406	812,815	0.1%	4.2%	-0.1%	0.3%	0.4%
TRANSMISSION LOSSES - kW	19,924	20,035	20,142	20,233	20,318	6.0%	2.8%	0.3%	0.4%	0.5%
TRANSMISSION LOSS (%)	2.4%	2.4%	2.4%	2.4%	2.4%	5.8%	-1.3%	0.4%	0.2%	0.1%
TOTAL CP - kW (WITH TRANSMISSION LOSSES)	816,994	821,541	825,936	829,639	833,133	0.2%	4.2%	0.0%	0.3%	0.4%
DEMAND RESPONSE (DR)- kW	2,177	2,177	2,177	2,177	2,177	-	-	-	-	-
TOTAL CP - kW WITHOUT DR (NO TX LOSSES)	799,247	803,683	807,971	811,583	814,992	0.1%	4.2%	0.0%	0.3%	0.4%

The following figures display the 2024 annual load shape and descending load curve for the Big Rivers Native system excluding transmission losses. The five-year monthly forecast is displayed 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	AUX	Total Energy Requirements	Transmission Losses	Total Energy Requirements with Losses	Rural CP	Direct Serve CP	AUX CP	Total CP	Transmission Losses	Total CP with Losses
2025	January	153,692	50,634	12,351	1	247	216,924	9,657	518	227,099	147,388	78	374,565	9,363	383,928	452,727	257,856	143	710,726	17,766	728,492
2025	February	129,287	43,661	13,117	1	247	186,313	8,294	435	195,042	132,376	78	327,496	8,186	335,682	432,337	255,654	143	688,134	17,201	705,335
2025	March	111,055	41,987	12,798	1	247	166,088	7,397	346	173,831	149,014	78	322,923	8,072	330,995	367,320	257,034	143	624,497	15,611	640,108
2025	April	86,085	38,822	12,455	3	247	137,612	6,137	284	144,032	144,420	78	288,530	7,212	295,743	280,733	259,073	143	539,949	13,497	553,446
2025	May	93,838	45,581	13,018	3	247	152,687	6,813	247	159,748	149,355	78	309,180	7,729	316,909	354,863	258,665	143	613,671	15,340	629,010
2025	June	117,093	55,106	13,343	18	246	185,807	8,292	273	194,372	150,661	78	345,110	8,627	353,737	430,487	268,418	143	699,048	17,474	716,522
2025	July	136,827	58,690	13,791	18	246	209,573	9,351	300	219,224	154,841	78	374,143	9,352	383,495	455,173	267,211	143	722,526	18,061	740,587
2025	August	132,576	56,496	13,815	18	246	203,151	9,066	308	212,526	155,365	78	367,969	9,198	377,167	454,819	267,982	143	722,144	18,051	740,196
2025	September	104,149	48,931	13,898	18	246	167,242	7,465	275	174,982	146,725	78	321,785	8,044	329,829	410,391	262,195	143	672,728	16,816	689,545
2025	October	87,501	45,706	13,184	3	246	146,640	6,539	261	153,441	154,553	78	308,072	7,701	315,773	333,283	266,885	143	600,310	15,006	615,316
2025	November	103,338	47,859	12,844	1	246	164,288	7,314	319	171,922	144,983	78	316,982	7,924	324,906	359,293	257,874	143	617,310	15,431	632,741
2025	December	137,280	52,278	12,789	1	246	202,594	9,018	430	212,042	155,381	78	367,501	9,186	376,687	416,429	265,836	143	682,407	17,058	699,465
2026	January	154,678	51,551	12,827	1	246	219,303	9,762	521	229,586	154,753	78	384,417	9,609	394,026	457,380	265,483	143	723,005	18,073	741,078
2026	February	130,314	44,458	13,551	1	246	188,570	8,393	438	197,402	138,636	78	336,116	8,402	344,517	436,971	263,346	143	700,460	17,509	717,969
2026	March	112,185	42,751	13,274	1	246	168,457	7,502	349	176,308	154,423	78	330,809	8,269	339,078	372,066	264,705	143	636,914	15,921	652,835
2026	April	87,119	39,522	12,917	3	246	139,807	6,233	286	146,326	149,667	78	296,070	7,401	303,471	284,942	266,452	143	551,536	13,787	565,323
2026	May	94,881	46,388	13,497	3	246	155,014	6,916	249	162,178	154,768	78	317,025	7,925	324,949	359,788	265,741	143	625,671	15,640	641,311
2026	June	117,999	56,047	13,809	18	245	188,118	8,393	275	196,786	155,820	78	352,684	8,816	361,500	435,575	274,606	143	710,323	17,756	728,079
2026	July	137,661	59,699	14,272	18	245	211,895	9,453	302	221,651	160,164	78	381,893	9,546	391,439	460,529	273,399	143	734,070	18,350	752,420
2026	August	133,465	57,482	14,295	18	245	205,506	9,170	310	214,986	160,691	78	375,755	9,393	385,147	459,231	274,173	143	733,547	18,336	751,883
2026	September	105,199	49,794	14,363	18	245	169,619	7,569	277	177,466	151,879	78	329,423	8,235	337,657	415,492	268,405	143	684,039	17,099	701,138
2026	October	88,533	46,523	13,663	3	245	148,968	6,641	263	155,872	158,954	78	314,903	7,872	322,775	337,908	271,880	143	609,930	15,246	625,176
2026	November	104,368	48,717	13,309	1	245	166,640	7,418	321	174,379	147,191	78	321,648	8,040	329,688	364,003	260,435	143	624,581	15,613	640,194
2026	December	138,310	53,210	13,267	1	245	205,033	9,125	433	214,591	155,821	78	370,490	9,261	379,751	421,123	266,017	143	687,282	17,180	704,462
2027	January	155,279	52,582	12,858	1	245	220,966	9,483	525	230,973	156,244	78	387,295	9,681	396,976	459,623	267,299	143	727,064	18,174	745,238
2027	February	131,029	45,350	13,583	1	245	190,208	8,165	441	198,814	139,961	78	338,852	8,470	347,323	439,214	265,124	143	704,480	17,610	722,090
2027	March	113,076	43,604	13,306	1	245	170,233	7,308	351	177,891	155,897	78	333,866	8,346	342,212	374,605	266,494	143	641,241	16,029	657,271
2027	April	87,988	40,286	12,949	3	245	141,471	6,075	288	147,833	151,108	78	299,018	7,475	306,493	287,563	268,210	143	555,916	13,896	569,812
2027	May	95,744	47,256	13,530	3	245	156,778	6,731	250	163,760	156,259	78	320,097	8,001	328,098	362,778	267,500	143	630,421	15,759	646,179
2027	June	118,660	57,059	13,844	18	244	189,826	8,153	276	198,255	157,371	78	355,704	8,892	364,595	438,471	277,285	143	715,899	17,895	733,794
2027	July	138,203	60,796	14,307	18	244	213,569	9,171	303	223,044	161,767	78	384,889	9,621	394,510	463,671	276,079	143	739,893	18,495	758,388
2027	August	134,072	58,545	14,331	18	244	207,211	8,900	312	216,423	162,296	78	378,797	9,469	388,266	462,173	276,857	143	739,173	18,477	757,650
2027	September	106,040	50,709	14,398	18	244	171,408	7,364	279	179,051	153,427	78	332,556	8,313	340,869	418,359	271,080	143	689,582	17,237	706,819
2027	October	89,403	47,367	13,698	3	244	150,715	6,473	264	157,452	160,564	78	318,094	7,951	326,046	340,623	274,572	143	615,338	15,382	630,719
2027	November	105,184	49,607	13,344	1	244	168,380	7,227	323	175,929	148,721	78	324,729	8,117	332,846	366,540	263,138	143	629,820	15,744	645,564
2027	December	139,022	54,202	13,299	1	244	206,768	8,874	435	216,077	157,417	78	373,572	9,338	382,910	423,507	268,741	143	692,391	17,308	709,699
2028	January	155,748	53,140	12,875	1	244	222,009	9,528	528	232,064	156,425	78	388,567	9,713	398,280	461,086	267,837	143	729,065	18,224	747,290
2028	February	131,653	45,836	13,599	1	244	191,333	8,213	443	199,989	140,108	78	340,175	8,503	348,678	425,483	261,396	143	687,022	17,173	704,195
2028	March	113,937	44,088	13,322	1	244	171,592	7,366	353	179,311	156,060	78	335,449	8,385	343,834	376,512	267,006	143	643,661	16,090	659,750
2028	April	88,873	40,725	12,965	3	244	142,809	6,132	289	149,230	151,272	78	300,580	7,514	308,094	289,807	268,719	143	558,669	13,965	572,634
2028	May	96,623	47,744	13,547	3	244	158,161	6,791	252	165,203	156,436	78	321,718	8,042	329,760	365,352	268,020	143	633,515	15,836	649,351
2028	June	119,311	57,600	13,862	18	243	191,034	8,204	278	199,517	157,525	78	357,119	8,927	366,046	440,817	277,778	143	718,737	17,966	736,703
2028	July	138,709	61,363	14,325	18	243	214,659	9,218	305	224,183	161,930	78	386,191	9,654	395,844	466,205	276,577	143	742,925	18,571	761,496
2028	August	134,641	59,103	14,349	18	243	208,355	8,949	314	217,618	162,462	78	380,158	9,503	389,661	464,502	277,361	143	742,005	18,548	760,553
2028	September	106,869	51,211	14,415	18	243	172,756	7,422	280	180,458	153,595	78	334,131	8,352	342,484	420,673	271,596	143	692,411	17,308	709,720
2028	October	90,278	47,853	13,715	3	243	152,092	6,532	266	158,889	160,746	78	319,713	7,992	327,705	342,897	275,096	143	618,136	15,452	633,587
2028	November	105,961	50,117	13,361	1	243	169,683	7,283	324	177,290	148,899	78	326,267	8,156	334,423	368,431	263,678	143	632,252	15,804	648,056
2028	December	139,622	54,749	13,316	1	243	207,931	8,924	437	217,293	157,607	78	374,978	9,373	384,351	425,188	269,293	143	694,623	17,363	711,987
2029	January	156,359	53,635	12,903	1	243	223,141	9,576	530	233,248	156,775	78	390,101	9,751	399,853	462,639	268,658	143	731,439	18,284	749,723
2029	February	132,384	46,271	13,627	1	243	192,526	8,265	446	201,236	140,403	78	341,717	8,542	350,259	442,134	266,419	143	708,696	17,715	726,412
2029	March	114,890	44,533	13,348	1	243	173,015	7,427	355	180,797	156,392	78	337,267	8,431	345,698	378,438	267,800	143	646,380	16,158	662,538
2029	April	89,827	41,127	12,993	3	243	144,192	6,191	291	150,674	151,599	78	302,351	7,558	309,909	292,077	269,513	143	561,732	14,042	575,774
2029	May	97,579	48,193	13,577	3	243	159,595	6,852	253	166,700	156,779	78	323,556	8,088	331,644	368,029	268,822	143	636,993	15,923	652,916
2029	June	120,063	58,098	13,891	18	242	192,313	8,259	279	200,852	157,849	78	358,779	8,968	367,747	443,279	278,568	143	721,989	18,048	740,037
2029	July	139,341	61,892	14,355	18	242	215,848	9,269	307	225,424	162,268	78	387,770	9,693	397,463	468,897	277,371	143	746,410	18,658	765,068
2029	August	135,328	59,620	14,380	18	242	209,588	9,002	315	218,905	162,803	78	381,786	9,544	391,330	466,966	278,159	143	745,268	18,629	763,897
2029	September	107,776	51,677	14,446	18	242	174,160	7,482	281	181,924	153,927	78	335,929	8,397	344,326	423,097	272,398	143	695,637	17,389	713,026
2029	October	91,227	48,307	13,744	3	242	153,522	6,593	267	160,383	161,098	78	321,559	8,038	329,597	345,254	275,911	143	621,307	15,531	636,838
2029	November	106,829	50,597	13,391	1	242	171,060	7,342	326	178,728	149,233	78	328,039	8,200	336,239	370,354	264,491	143	634,988	15,873	650,861
2029	December	140,343	55,263	13,344	1	242	209,192	8,978	439	218,610	157,963	78	376,651	9,415	386,066	426,962	270,123	143	697,227	17,429	714,656

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

JPEC Residential Use Per Consumer Model				
Sample: 2007 - 2024 **Total Observations: 216**				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
January	6.356004	0.054101	117.4851	0
February	6.285362	0.046355	135.5921	0
March	6.287526	0.040573	154.9685	0
April	6.196797	0.036411	170.1916	0
May	6.323411	0.036941	171.1754	0
June	6.444005	0.045748	140.858	0
July	6.510996	0.050874	127.9839	0
August	6.507406	0.046695	139.3612	0
September	6.414312	0.038791	165.3562	0
October	6.220661	0.037602	165.436	0
November	6.214555	0.044146	140.774	0
December	6.353898	0.047734	133.1112	0
Log(Residential Price/Allernate Fuel Price)	-0.136674	0.01289	-10.60319	0
Cooling Degree Days*(AC Saturation)*(1/AC Efficiency)	0.014272	0.000994	14.36492	0
Heating Degree Days*Electric Heat Saturation*(1/Heating Efficiency)	0.015221	0.001041	14.61919	0
Weighted Statistics				
Adjusted R-squared: 0.938612				

JPEC General C&I Consumer Model				
Sample: 2007 - 2024				
Total Observations: 216				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
GRP	**1.462378**	**0.182071**	**8.031907**	**0**
Total Retail Sales	**1.825062**	**0.464342**	**3.930425**	**0.0001**
January 2007 - July 2015	**-957.9848**	**28.76752**	**-33.30092**	**0**
March 2023 Forward	**1584.417**	**23.9511**	**66.15217**	**0**
Weighted Statistics				
Adjusted R-squared: 0.971216				

JPEC General C&I Use Per Consumer Model

Sample: 1999 - 2024
Total Observations: 312

Variable	Coefficient	Std. Error	t-Statistic	Prob.
January	8.737869	0.269173	32.46188	0
February	8.659172	0.267345	32.38948	0
March	8.708107	0.265711	32.77289	0
April	8.721812	0.26209	33.27795	0
May	8.802069	0.262898	33.48095	0
June	8.794744	0.261451	33.63827	0
July	8.813628	0.262529	33.57198	0
August	8.823566	0.261778	33.70623	0
September	8.816972	0.260105	33.89777	0
October	8.791557	0.265923	33.0605	0
November	8.738667	0.267037	32.72451	0
December	8.725712	0.268397	32.51047	0
Log(C&I Electricity Price)	-0.180507	0.049028	-3.681699	0.0003
Cooling Degree Days	0.000655	0.0000909	7.203554	0
Heating Degree Days	0.000268	0.0000516	5.185183	0
Log(Total Employment/C&I Consumers)	0.197384	0.037799	5.221937	0
January 1999 - July 2015	0.068057	0.018328	3.713194	0.0002
2019 Forward	-0.153807	0.013349	-11.52205	0
March 2023 Forward	-0.209066	0.019993	-10.45714	0

Weighted Statistics

Adjusted R-squared: 0.921662

JPEC Load Factor Model

Sample: 2007 - 2024
Total Observations: 216

Variable	Coefficient	Std. Error	t-Statistic	Prob.
January	0.66742	0.029978	22.264	0
February	0.702502	0.022996	30.54885	0
March	0.687266	0.020453	33.6017	0
April Cold Peaking	0.719861	0.016514	43.59061	0
April Hot Peaking	0.666042	0.021301	31.26803	0
May	0.608436	0.017238	35.2965	0
June	0.627201	0.024192	25.92595	0
July	0.609343	0.026453	23.03459	0
August	0.610935	0.026438	23.1079	0
September	0.61898	0.022403	27.62923	0
October Cold Peaking	0.758811	0.018299	41.46686	0
October Hot Peaking	0.621897	0.023036	26.99716	0
November	0.697464	0.021983	31.72781	0
December	0.69224	0.026078	26.54482	0
Cooling Degree Days on Peak Day*(AC Saturation)*(1/AC Efficiency)	-0.106743	0.015887	-6.718695	0
Heating Degree Days on Peak Day*Electric Heating Saturation*(1/Heating Efficiency)	-0.112427	0.013488	-8.335535	0
Cooling Degree During Remainder of Month*(AC Saturation)*(1/AC Efficiency)	0.00567	0.000596	9.519213	0
Heating Degree During Remainder of Month*Electric Heating Saturation*(1/Heating Efficiency)	0.00593	0.00079	7.510727	0
September 2023 Forward	0.016056	0.008689	1.847829	0.0661

Weighted Statistics

Adjusted R-squared: 0.723536

The following tables provide the econometric models for Kenergy Corporation.

Kenergy Residential Use Per Consumer Model				
Sample: 2007 - 2024 **Total Observations: 216**				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
January	**6.555956**	**0.046206**	**141.8868**	**0**
February	**6.520052**	**0.046264**	**140.9325**	**0**
March	**6.544898**	**0.045682**	**143.2717**	**0**
April	**6.472937**	**0.045977**	**140.7869**	**0**
May	**6.563771**	**0.041671**	**157.5153**	**0**
June	**6.649759**	**0.046607**	**142.6781**	**0**
July	**6.74539**	**0.04781**	**141.0873**	**0**
August	**6.749728**	**0.04645**	**145.3106**	**0**
September	**6.655292**	**0.045556**	**146.0902**	**0**
October	**6.467343**	**0.044107**	**146.6281**	**0**
November	**6.411435**	**0.041835**	**153.2542**	**0**
December	**6.518332**	**0.046077**	**141.465**	**0**
Log(Residential Price/Allernate Fuel Price)	**-0.086282**	**0.015767**	**-5.472294**	**0**
Cooling Degree Days*(AC Saturation)*(1/AC Efficiency)	**0.01136**	**0.000768**	**14.78422**	**0**
Heating Degree Days*Electric Heat Saturation*(1/Heating Efficiency)	**0.011903**	**0.000801**	**14.85851**	**0**
Weighted Statistics				
Adjusted R-squared: 0.910317				

Kenergy General C&I Consumer Model

Sample: 2007 - 2024
Total Observations: 216

Variable	Coefficient	Std. Error	t-Statistic	Prob.
GRP	**0.747971**	**0.226122**	**3.307825**	**0.0011**
Total Retail Sales	**2.029809**	**0.630736**	**3.218162**	**0.0015**
Total Employment	**53.96955**	**12.85332**	**4.198879**	**0**
October 2019 Forward	**1040.25**	**141.3978**	**7.356908**	**0**

Weighted Statistics

Adjusted R-squared: 0.856533

Kenergy General C&I Use Per Consumer Model

Sample: 1999 - 2024
Total Observations: 312

Variable	Coefficient	Std. Error	t-Statistic	Prob.
January	11.01276	0.20787	52.97895	0
February	10.91945	0.205724	53.07814	0
March	10.98792	0.205202	53.54685	0
April	10.98592	0.205127	53.55656	0
May	11.1584	0.204074	54.67816	0
June	11.27811	0.202705	55.638	0
July	11.26025	0.203743	55.26706	0
August	11.22236	0.204233	54.94883	0
September	11.20827	0.203678	55.02942	0
October	11.19335	0.204617	54.70382	0
November	11.16471	0.203757	54.79429	0
December	11.16011	0.207439	53.79936	0
Log(C&I Electricity Price)	-0.064888	0.033415	-1.94188	0.0531
Cooling Degree Days	0.000902	0.0000899	10.02972	0
Heating Degree Days	0.0005	0.0000574	8.70793	0
Log(Total Employment/C&I Consumers)	0.72474	0.032759	22.12306	0
October 2019 Forward	-0.066088	0.016674	-3.963579	0.0001

Weighted Statistics

Adjusted R-squared: 0.88911

Kenergy Load Factor Model

Sample: 2007 - 2024
Total Observations: 216

Variable	Coefficient	Std. Error	t-Statistic	Prob.
January	0.708903	0.024367	29.09223	0
February	0.73064	0.021724	33.63351	0
March	0.698413	0.019775	35.31843	0
April Cold Peaking	0.720601	0.015521	46.42677	0
April Hot Peaking	0.703952	0.025383	27.73344	0
May	0.619211	0.014654	42.25646	0
June	0.620672	0.017625	35.21443	0
July	0.611188	0.017627	34.67261	0
August	0.6106	0.017115	35.67719	0
September	0.621394	0.01726	36.00239	0
October Cold Peaking	0.777861	0.01523	51.07486	0
October Hot Peaking	0.626101	0.017686	35.40139	0
November	0.72096	0.018885	38.17706	0
December	0.71463	0.021639	33.02523	0
Cooling Degree Days on Peak Day*(AC Saturation)*(1/AC Efficiency)	-0.105363	0.013556	-7.772624	0
Heating Degree Days on Peak Day*Electric Heating Saturation*(1/Heating Efficiency)	-0.105687	0.011523	-9.172034	0
Cooling Degree During Remainder of Month*(AC Saturation)*(1/AC Efficiency)	0.005594	0.00053	10.56108	0
Heating Degree During Remainder of Month*Electric Heating Saturation*(1/Heating Efficiency)	0.00437	0.000503	8.695825	0
September 2023 Forward	0.016697	0.010678	1.563701	0.1195

Weighted Statistics

Adjusted R-squared: 0.704809

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

MCRECC Residential Use Per Consumer Model				
Sample: 2007 - 2024 **Total Observations: 216**				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
January	**6.340957**	**0.033663**	**188.3633**	**0**
February	**6.291554**	**0.032258**	**195.041**	**0**
March	**6.315064**	**0.028843**	**218.9463**	**0**
April	**6.21258**	**0.02637**	**235.5963**	**0**
May	**6.277072**	**0.026315**	**238.5359**	**0**
June	**6.343323**	**0.031036**	**204.3863**	**0**
July	**6.397008**	**0.032256**	**198.3186**	**0**
August	**6.365689**	**0.032221**	**197.564**	**0**
September	**6.283779**	**0.02957**	**212.5087**	**0**
October	**6.226639**	**0.02618**	**237.8392**	**0**
November	**6.282394**	**0.029009**	**216.5685**	**0**
December	**6.35806**	**0.032553**	**195.3132**	**0**
Log(Residential Price/Alternate Fuel Price)	**-0.074133**	**0.009018**	**-8.220959**	**0**
Cooling Degree Days*(AC Saturation)*(1/AC Efficiency)	**0.012756**	**0.0006**	**21.27739**	**0**
Heating Degree Days*Electric Heat Saturation*(1/Heating Efficiency)	**0.011473**	**0.000434**	**26.42756**	**0**
Weighted Statistics				
Adjusted R-squared: 0.976346				

MCRECC General C&I Consumer Model				
Sample: 2007 - 2024 **Total Observations: 216**				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
Total Employment	**132.2433**	**0.181661**	**727.9692**	**0**
Weighted Statistics				
Adjusted R-squared: 0.247584				

MCRECC General C&I Use Per Consumer Model

Sample: 1999 - 2024
Total Observations: 312

Variable	Coefficient	Std. Error	t-Statistic	Prob.
January	10.01593	0.358746	27.91932	0
February	10.00655	0.357903	27.95883	0
March	10.02932	0.355979	28.17391	0
April	10.05329	0.35953	27.96234	0
May	10.14986	0.357723	28.37351	0
June	10.17034	0.35682	28.50272	0
July	10.18853	0.357657	28.4869	0
August	10.19953	0.35857	28.44503	0
September	10.17119	0.357463	28.4538	0
October	10.18201	0.358025	28.43935	0
November	10.10374	0.359591	28.09785	0
December	10.06497	0.359091	28.02902	0
Log(C&I Electricity Price)	-0.330445	0.102896	-3.211446	0.0015
Cooling Degree Days	0.000582	0.000077	7.554709	0
Heating Degree Days	0.000314	0.0000408	7.708104	0
Log(Total Employment/C&I Consumers)	0.571089	0.09463	6.034971	0
2013 Forward	-0.110458	0.025257	-4.373339	0
2016 Forward	-0.164897	0.021375	-7.714298	0

Weighted Statistics

Adjusted R-squared: 0.896232

MCRECC Load Factor Model

Sample: 2007 - 2024
Total Observations: 216

Variable	Coefficient	Std. Error	t-Statistic	Prob.
January	0.674019	0.019332	34.86559	0
February	0.702757	0.017851	39.36785	0
March	0.669223	0.014328	46.70624	0
April Cold Peaking	0.665737	0.012498	53.26685	0
April Hot Peaking	0.749352	0.025065	29.89665	0
May	0.65194	0.022714	28.7018	0
June	0.640122	0.025189	25.41243	0
July	0.632376	0.025827	24.4847	0
August	0.629411	0.025806	24.38975	0
September	0.63534	0.02326	27.31421	0
October Cold Peaking	0.691164	0.014263	48.45879	0
October Hot Peaking	0.660285	0.023952	27.56674	0
November	0.673629	0.014814	45.47279	0
December	0.671029	0.01691	39.6825	0
Cooling Degree Days on Peak Day*(AC Saturation)*(1/AC Efficiency)	-0.130293	0.017655	-7.379819	0
Heating Degree Days on Peak Day*Electric Heating Saturation*(1/Heating Efficiency)	-0.122123	0.006605	-18.48973	0
Cooling Degree During Remainder of Month*(AC Saturation)*(1/AC Efficiency)	0.00573	0.000572	10.01646	0
Heating Degree During Remainder of Month*Electric Heating Saturation*(1/Heating Efficiency)	0.005517	0.000318	17.36004	0
September 2023 Forward	0.008944	0.010041	0.89078	0.3741

Weighted Statistics

Adjusted R-squared: 0.785219

APPENDIX B

DEMAND-SIDE MANAGEMENT POTENTIAL STUDY

MARKET POTENTIAL STUDY REPORT

July 2026

Big Rivers Electric Corporation

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01 EXECUTIVE SUMMARY

1.1 BACKGROUND

This study examines the potential to reduce electric consumption and peak demand through the implementation of demand side management ("DSM") technologies and practices in residential and non-residential facilities. DSM potential studies are important and helpful tools for identifying those DSM measures that are the most cost-effective and have the most electricity savings potential. To assess energy efficiency and demand response, the study estimates technical potential, economic potential, and achievable potential. These potentials are estimated throughout Big Rivers Members' service territories over a period of fifteen years, from 2027 through 2041. Results from three program potential scenarios are also presented to estimate the portion of the achievable potential that could be attained given specific funding levels for Big Rivers DSM programs.

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 was the best available at the time this analysis was developed. As building and appliance codes and energy efficiency standards change, and as energy prices fluctuate, additional opportunities for energy efficiency may occur while current practices may become outdated. Actual energy and demand savings will depend upon the level and degree of voluntary member system participation in DSM programs.

1.2 STUDY OBJECTIVES

The study had five primary objectives:

1. Develop databases of energy efficiency and demand response measures in the residential and non-residential sectors. The measure databases reflect current industry knowledge of energy efficiency and demand response measures, account for known codes and standards, and align with the market and demographics of Big Rivers Members' customers.
2. Evaluate the electric DSM technical potential savings in Big Rivers Members' territories.
3. Determine the economic potential savings using the Total Resource Cost ("TRC") test benefit-cost ratio for potential electric energy efficiency measures.
4. Evaluate the potential for achievable savings through DSM programs over a fifteen-year horizon (2027-2041).
5. Estimate the total savings over a fifteen-year period from the delivery of a portfolio of programs based on three specific funding scenarios: a $1.0 million annual incentive budget, a $3.0 million annual incentive budget and a $5.0 million annual incentive budget. 50% of the total funding was applied to energy efficiency, and 50% was applied to demand response, such that the portfolio of energy efficiency programs and the portfolio of demand response programs were each analyzed based on three funding scenarios: a $0.5 million annual incentive budget, a $1.5 million annual incentive budget and a $2.5 million annual incentive budget.

1.3 DESCRIPTION OF THE FOUR TYPES OF POTENTIAL ESTIMATED

The scope of this study distinguishes four types of potential: (1) technical, (2) economic, (3) achievable, and (4) program.

1. **Technical Potential** is the theoretical maximum amount of energy use that could be displaced by efficiency, disregarding all non-engineering constraints such as cost-effectiveness and the willingness of end users to adopt the efficiency measures. Technical potential is constrained only by factors such as technical feasibility and applicability of measures.
2. **Economic Potential** refers to the subset of the technical potential that is economically cost-effective as compared to conventional supply-side energy resources. Economic potential follows the same adoption rates as technical potential. Like technical potential, the economic scenario ignores market barriers to ensuring actual implementation of efficiency. Finally, economic potential only considers the costs of efficiency measures themselves, ignoring any programmatic costs (e.g., marketing, analysis, administration) that would be necessary to capture them.[1]
3. **Achievable Potential** is the amount of energy use that efficiency can realistically be expected to displace, assuming the most aggressive program scenario possible (e.g., providing end users with payments for the entire incremental cost of more efficient equipment). Achievable potential considers real-world barriers to encouraging end users to adopt efficiency measures, the non-measure costs of delivering programs (for administration, marketing, tracking systems, and monitoring and evaluation), and the capability of programs and administrators to boost program activity over time.[2]
4. **Program Potential** is the amount of potential that can be achieved given specific funding levels and program designs.

1.4 SUMMARY OF ENERGY EFFICIENCY POTENTIAL

Figure 1-1 provides the technical, economic, achievable and program potential (three funding scenarios) across all sectors in the Big Rivers service territory. The economic potential is approximately 23% of forecasted sales by 2041. The portfolio of energy efficiency programs, including residential and non-residential programs, was analyzed based on three funding scenarios: a $2.5 million annual incentive budget, a $1.5 million annual incentive budget and a $0.5 million annual incentive budget. The program potential at the $0.5 million incentive scenario is approximately 1% of forecasted sales by 2041.

[1] National Action Plan for Energy Efficiency, "Guide for Conducting Energy Efficiency Potential Studies" (November 2007), page 2-4.
[2] ibid.

FIGURE 1-1. ELECTRIC EFFICIENCY POTENTIAL SAVINGS SUMMARY

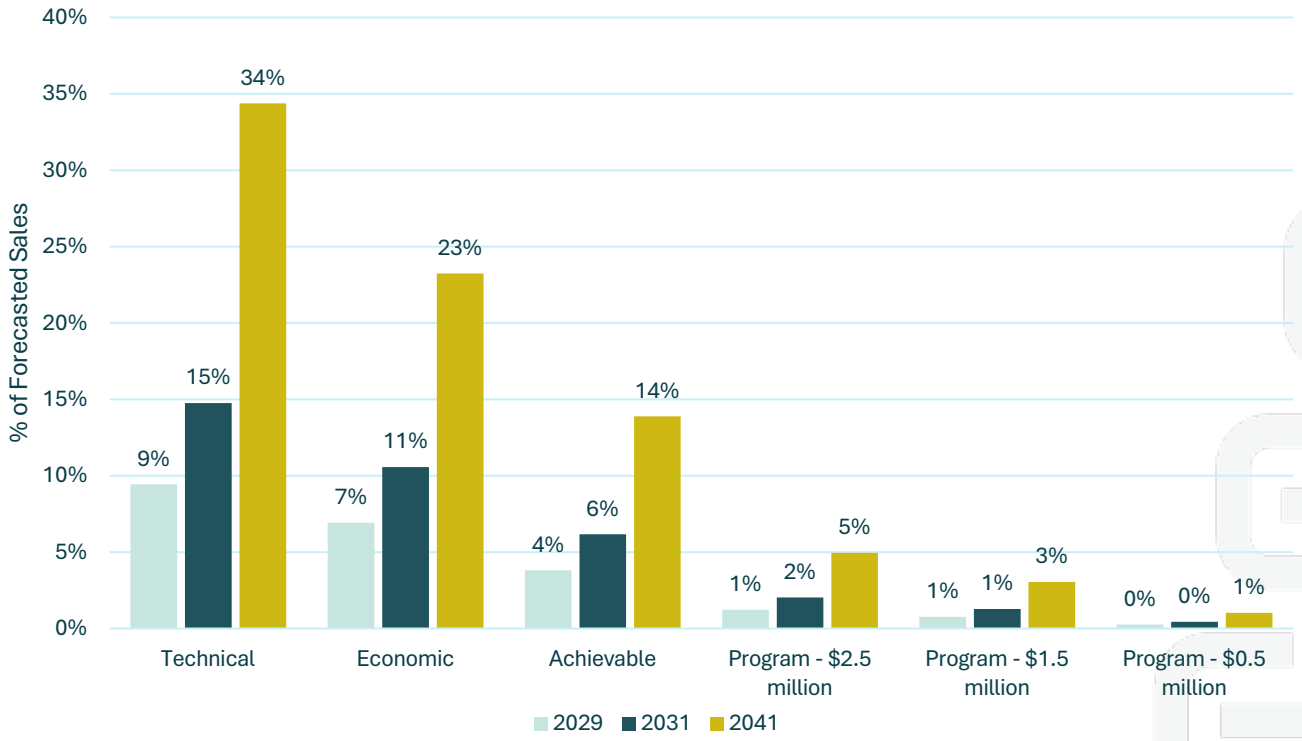


Table 1-1 provides the 15-year energy, summer demand, and winter demand potential.

TABLE 1-1. 15-YEAR CUMULATIVE SUMMARY RESULTS FOR ENERGY AND DEMAND

Potential Savings	MWh	Summer MW	Winter MW
Technical	792,672	188.7	131.2
Economic	535,956	106.4	107.8
Achievable	320,328	54.6	56.9
Program - $2.5 million	114,239	23.7	21.7
Program - $1.5 million	70,317	14.3	11.8
Program - $0.5 million	23,753	4.5	3.7

Additional details of the energy efficiency potential are provided in chapters 3, 4, and 5.

1.5 SUMMARY OF DEMAND RESPONSE POTENTIAL

Similar to the energy efficiency analysis, achievable potential for demand response was calculated based on estimates of the amount of demand response that could be realistically achieved over the study period. Program potential was then considered at three different funding scenarios: a $2.5 million scenario, a $1.5 million scenario, and a $0.5 million scenario. Summer demand potential is shown in Figure 1-2 in 2029, 2031, and 2041. Table 1-2 shows the summer and winter demand potential in 2041.

FIGURE 1-2. DEMAND RESPONSE POTENTIAL SAVINGS SUMMARY

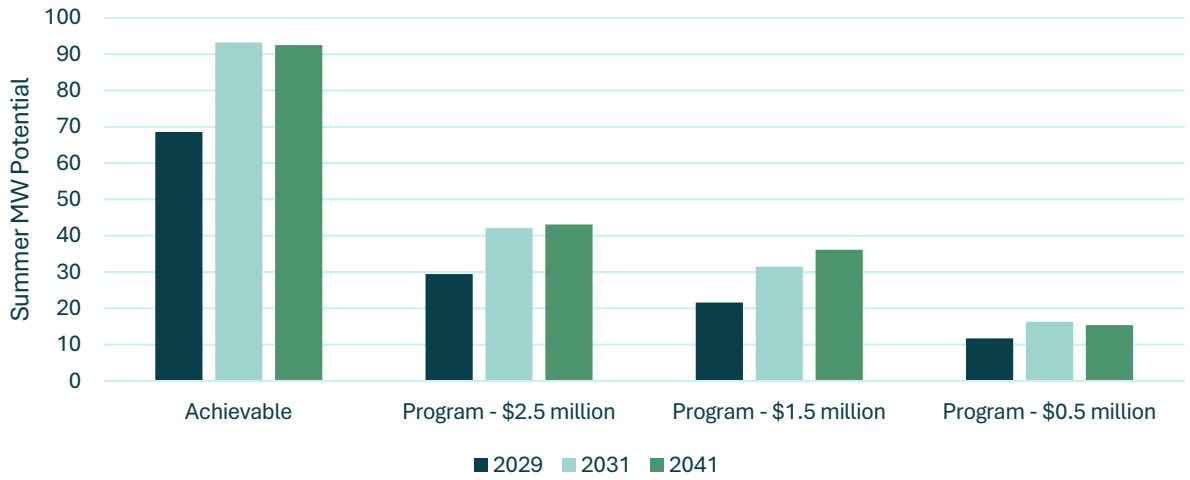


TABLE 1-2. SUMMARY RESULTS FOR CUMULATIVE DEMAND RESPONSE IN FINAL YEAR OF STUDY

Potential Savings	Summer MW	Winter MW
Achievable	92.6	82.6
Program - $2.5 million	43.1	43.5
Program - $1.5 million	36.1	32.8
Program - $0.5 million	15.4	16.0

02 METHODOLOGY

This chapter thoroughly describes the analytical approach utilized to develop the energy efficiency potential study for Big Rivers. The main objectives of the study were to estimate the technical, economic, and achievable potential savings from energy efficiency and demand response (see Chapter 6 for demand response methodology details); and to quantify these estimates of potential in terms of MWh and MW savings, for each level of energy efficiency potential. This document describes the general steps and methods that were used at each stage of the analytical process necessary to produce the various estimates of energy efficiency potential.

Energy efficiency potential studies involve several analytical steps to produce estimates of each type of energy efficiency potential: technical, economic, and achievable. This study utilizes benefit/cost screening tools for the residential and non-residential sectors to assess the cost effectiveness of energy efficiency measures. These cost effectiveness screening tools are Excel-based models that integrate technology-specific impacts and costs, customer characteristics, utility avoided cost forecasts and more. Excel was used as the modeling platform to provide transparency to the estimation process and allow for simple customization based on Big Rivers' unique characteristics and the availability of specific model input data. The major analytical steps and an overview of the potential savings are summarized below, and specific changes in methodology from one sector to another have been noted throughout this section.

2.1 OVERVIEW OF APPROACH

For the residential sector, GDS took a bottom-up approach to the modeling, whereby measure-level estimates of costs, savings, and useful lives were used as the basis for developing the technical, economic, and achievable potential estimates. The measure data was used to build up the technical potential, by applying the data to each relevant market segment. The measure data also allowed for benefit-cost screening to assess economic potential. The economic potential was used as the basis for achievable potential, which took into consideration incentives and estimates of annual adoption rates.

For the commercial and industrial sectors, GDS took a bottom-up modeling approach to first estimate measure-level savings and costs as well as cost-effectiveness and then applied cost-effective measure savings to all applicable shares of energy load. Disaggregated forecast data served as the foundation for the development of the energy efficiency potential estimates. The disaggregated forecast was developed using regional data from the Energy Information Administration's (EIA) Annual Energy Outlook (AEO).

2.2 MARKET CHARACTERIZATION

The initial step in the analysis was to gather a clear understanding of the current market segments in the Big Rivers service area. The GDS team coordinated with Big Rivers to gather utility sales and customer data and existing market research to define appropriate market sectors and market segments. This information served as the basis for completing a forecast disaggregation and market characterization of both the residential and non-residential sectors.

In the commercial and industrial sectors, disaggregated forecast data provides the foundation for the development of energy efficiency potential estimates. GDS disaggregated the commercial sector sales into building type using data from the US Energy Information Administration (EIA) 2024 Annual Energy Outlook data for the East South-Central Census region. For the industrial sector, the baseline electric forecasts were disaggregated by industry type using estimates from EIA Manufacturing Energy Consumption Survey (MECS) for the same region.

GDS further disaggregated sales for each of the segments into end uses. For commercial segments, GDS again primarily used EIA data for the East South-Central Census region. For the industrial sector, the analysis relied on the EIA's Manufacturing Energy Consumption survey to disaggregate industry-specific estimates of electric consumption into end uses.

- ***Residential.*** The residential forecast was broken out by housing type and construction vintage (new construction vs. existing homes).
- ***Commercial.*** Typically based on major EIA business types: assembly, retail, warehouse, food sales, office, lodging, health, food service, education, and miscellaneous.
- ***Industrial.*** As determined by actual load consumption shares and major industry types as defined by EIA's Manufacturing Energy Consumption Survey (MECS) data.

Within the residential, commercial, and industrial market segments, the sector level disaggregated forecasts were further segmented by the major end uses shown in Table 2-1.

TABLE 2-1. ELECTRIC END USE LOADS

Residential	Non-residential
Refrigerator	Behavioral
Clothes Washer	Compressed Air
Dishwasher	Cooking
Dehumidifier	Cooling
Freezer	Exterior Lighting
Heating	Heating
Cooling	Water Heating
Lighting	Interior Lighting
Pool	Miscellaneous
Plug Load	Motors
HVAC Shell	Office Loads
Water Heating	Refrigeration
Cross-Cutting	Ventilation
	Whole Building
	Whole Building HVAC
	Whole Building NC
	Industrial Compressed Air
	Industrial HVAC
	Industrial Interior Lighting
	Industrial Motors
	Industrial Process Heat
	Industrial Process Refrigeration
	Industrial Process Other
	Industrial Whole Building
	Industrial Water & Wastewater
	Agriculture Motors
	Agriculture Refrigeration
	Agriculture Interior Lighting
	Agriculture Ventilation
	Agriculture HVAC

2.3 MEASURE CHARACTERIZATION

This section of the report provides an overview of the measure lists used in the study as well as the assumptions and sources used to characterize these measures.

2.3.1 Measure Lists

The energy efficiency measures included in this study are currently commercially available as well as emerging technologies. The commercially available measures are of the most immediate interest to Big Rivers. These measure lists were then reviewed, discussed, and updated as necessary. A complete listing of the energy efficiency measures included in this study is provided in the Appendices of this report.

In addition, this study includes measures that could be relatively easily substituted for, or applied to, existing technologies on a retrofit or replace-on-burnout basis. Replace-on-burnout applies to equipment replacements that are normally made in the market when a piece of equipment is at the end of its useful life. A retrofit measure is eligible to be replaced at any time in the life of the equipment or building. Replace-on-burnout measures are generally characterized by incremental measure costs and savings (e.g. the costs and savings of a high-efficiency versus standard efficiency air conditioner); whereas retrofit measures are generally characterized by full costs and savings (e.g. the full costs and savings associated with adding ceiling insulation into an existing attic). For new construction, energy efficiency measures can be implemented when each new home or building is constructed, thus the rate of availability is a direct function of the rate of new construction.

In total, GDS analyzed 241 measure types for Big Rivers. Many measures required multiple permutations for different applications, such as different building types, efficiency levels, and replacement options. GDS developed a total of 1,722 measure permutations for this study. Table 2-2 provides a breakdown of the sector-level number of measures and permutations.

TABLE 2-2. MEASURE COUNTS BY SECTOR

Sector	# of Measures	Total Permutations
Residential	86	424
C&I	155	1,298
Total	241	1,722

2.3.2 Assumptions and Sources

A significant amount of data is needed to estimate the kWh and kW savings potential for individual energy efficiency and demand response measures or programs across the entire existing residential and non-residential sectors for Big Rivers. GDS used Kentucky specific data wherever it was available and up to date. Considerable effort was expended to identify, review, and document all available data sources.

This review has allowed the development of reasonable and supportable assumptions regarding measure lives; measure installed incremental or full costs (as appropriate); and electric savings and saturations for each energy efficiency measure included in the final list of measures in this study.

Costs and savings for new construction and replace-on-burnout measures are calculated as the incremental difference between the code minimum equipment and the energy efficiency measure. This approach is utilized because the consumer must select an efficiency level that is at least the code minimum equipment. The incremental cost is calculated as the difference between the cost of high efficiency and standard (code compliant) equipment.

However, for retrofit measures, the measure cost is considered the "full" cost of the measure, as the baseline scenario assumes the consumer would do nothing. In general, the savings for retrofit measures are calculated as the difference between the energy use of the removed equipment and the energy use of the new high efficiency equipment (until the removed equipment would have reached the end of its useful life). For measures like insulation, the savings are calculated based on the consumption before and after the installation of improved insulation levels.

Measure Savings: GDS utilized several sources including the 2025 Illinois TRM to inform calculations supporting estimates of annual measure savings as a percentage of base equipment usage. Other sources used include:

- Mid-Atlantic TRM, Maine TRM, Minnesota TRM, and other existing deemed savings databases
- Secondary sources such as the American Council for an Energy-Efficient Economy (ACEEE), Department of Energy (DOE), Energy Information Administration (EIA), ENERGY STAR©, and other technical potential studies

Measure Costs: Measure costs represent either incremental or full costs. These costs typically include the incremental cost of measure installation, when appropriate based on the measure definition. For purposes of this study, nominal measure costs held constant over time.

GDS obtained measure cost estimates from a variety of sources, starting with the 2021 Ill TRM. Other sources leveraged include:

- Mid-Atlantic TRM, Indiana TRM, Maine TRM, Minnesota TRM, and other existing deemed savings databases
- Secondary sources such as the ACEEE, ENERGY STAR, National Renewable Energy Lab (NREL), California Database for Energy Efficient Resources (DEER) database, Northeast Energy Efficiency Partnership (NEEP) Incremental Cost Study, and other technical potential studies

Measure Life: Measure life represents the number of years that energy using equipment is expected to operate. GDS obtained measure life estimates from the 2021 Ill TRM, and used the following other data sources:

- TRMs in other states
- Manufacturer data
- Savings calculators and life-cycle cost analyses
- The California DEER database
- Other consultant research or technical reports

Building/Equipment Saturation Data: To assess the amount of electric energy efficiency savings still available, estimates of the current saturation of baseline equipment and energy efficiency measures for the residential sector are necessary. For the non-residential sector, the amount of energy use that is associated with a specific end use (such as HVAC) and the percent of that energy use that is associated with energy efficient equipment are needed. Up-to-date measure saturation data were primarily obtained from the following recent studies:

- 2025 Big Rivers End Use Saturation Surveys
- 2020 EIA Residential Energy Consumption Survey (RECS)
- Energy Star Unit Shipment Data
- 2024 EIA Annual Energy Outlook
- EIA Baseline Energy Calculator
- 2023 Pennsylvania Baseline Study

2.4 ENERGY EFFICIENCY POTENTIAL

This section provides an overview of the types of potential and key considerations in assessing each level of energy efficiency potential.

2.4.1 Types of Potential

This section reviews the types of potential analyzed in this report, as well as some key methodological considerations in the development of technical, economic, and achievable potential.

The first two types of potential, technical and economic, provide a theoretical upper bound for energy savings from energy efficiency measures. Still, even the best-designed portfolio of programs is unlikely to capture 100% of the technical or economic potential. Therefore, achievable potential attempts to estimate what savings can be realistically achieved through market interventions, when it can be captured, and how much it would cost to do so. Figure 2-1 illustrates the types of energy efficiency potential considered in this analysis.

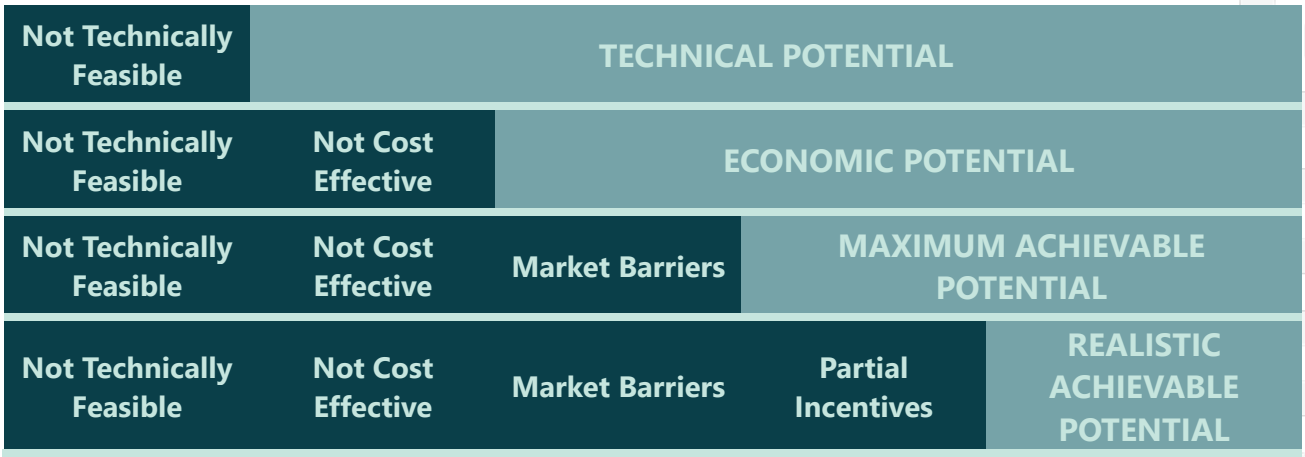


FIGURE 2-1. TYPE OF ENERGY EFFICIENCY POTENTIAL[3]

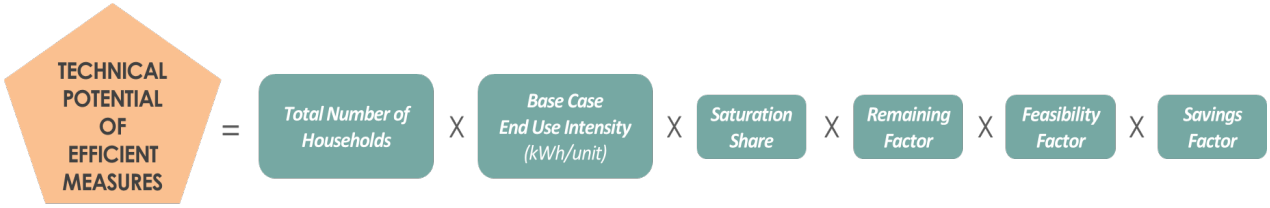
2.4.2 Technical Potential

Technical potential is the theoretical maximum amount of energy use that could be displaced by efficiency, disregarding all non-engineering constraints such as cost-effectiveness and the willingness of end users to adopt the efficiency measures. Technical potential is only constrained by factors such as technical feasibility and applicability of measures. Under technical potential, GDS assumed that 100% of new construction and market opportunity measures are adopted as those opportunities become available (e.g., as new buildings are constructed, they immediately adopt efficiency measures, or as existing measures reach the end of their useful life). For retrofit measures, implementation was assumed to be resource constrained and that it was not possible to install all retrofit measures all at once. Rather, retrofit opportunities were assumed to be replaced incrementally until 100% of stock was converted to the efficient measure over a period of no more than 20 years.

The core equation used in the residential sector energy efficiency technical potential analysis for each individual efficiency measure is shown in Equation 2-1 below. The C&I sector employs a similar analytical approach.

[3] Reproduced from "Guide to Resource Planning with Energy Efficiency." November 2007. US Environmental Protection Agency (EPA). Figure 2-1. Modified to depict the additional levels of achievable and program potential included in this study.

EQUATION 2-1 CORE EQUATION FOR RESIDENTIAL SECTOR TECHNICAL POTENTIAL



Where…

Base Case Equipment End Use Intensity = the electricity used per customer per year by each base case technology in each market segment. In other words, the base case equipment end use intensity is the consumption of the electrical energy using equipment that the efficient technology replaces or affects.

Saturation Share = the fraction of the end use electrical energy that is applicable for the efficient technology in each market segment. For example, for residential water heating, the saturation share would be the fraction of all residential electric customers that have electric water heating in their household.

Remaining Factor = the fraction of equipment that is not considered to already be energy efficient. To extend the example above, the fraction of electric water heaters that is not already energy efficient.

Feasibility Factor = (also functions as the applicability factor) the fraction of the applicable units that is technically feasible for conversion to the most efficient available technology from an engineering perspective (e.g., it may not be possible to install heat pump water heaters in all homes because of space limitations).

Savings Factor = the percentage reduction in electricity consumption resulting from the application of the efficient technology.

Competing Measures & Interactive Effects Adjustments

GDS prevents double-counting of savings, and accounts for competing measures and interactive savings effects, through three primary adjustment factors:

Baseline Saturation Adjustment. Competing measure shares are factored into the baseline saturation estimates. For example, nearly all homes can receive insulation. To account for this, GDS' analysis used multiple measure permutations that account for varying impacts of different heating/cooling combinations and baseline saturations were applied to reflect the proportions of households with each heating/cooling combination.

Applicability Factor Adjustment. Combined measures into measure groups, where total applicability factor across measures is set to 100%. For example, homes cannot receive a programmable thermostat, connected thermostat, and smart thermostat. In general, the models assign the measure with the most savings the greatest applicability factor in the measure group, with competing measures picking up any remaining share.

Interactive Savings Adjustment. As savings are introduced from select measures, the per-unit savings from other measures need to be adjusted (downward) to avoid over-counting. The analysis typically prioritizes market opportunity equipment measures (versus retrofit measures that can be installed at any time). For example, the savings from a smart thermostat and other HVAC related weatherization measures like insulation and air sealing are adjusted down to reflect the efficiency gains of installing an efficient air source heat pump.

2.4.3 Economic Potential

Economic potential refers to the subset of the technical potential that is economically cost-effective (based on screening with the TRC test) as compared to conventional supply-side energy resources.

2.4.4 Achievable Potential

Achievable potential is the amount of energy that can realistically be saved given various market barriers. Achievable potential considers real-world barriers to encouraging end users to adopt efficiency measures; the non-measure costs of delivering programs (for administration, marketing, analysis, and EM&V[4]); and the capability of programs and administrators to boost program activity over time. Barriers include financial, customer awareness and willingness-to-participate ("WTP") in programs, technical constraints, and other barriers the "program intervention" is modeled to overcome. Additional considerations include political and/or regulatory constraints.

2.4.4.1 Market Adoption Rates

GDS assessed achievable potential on a measure-by-measure basis. In addition to accounting for the natural replacement cycle of equipment in the achievable potential scenario, GDS estimated measure specific maximum adoption rates that reflect the presence of possible market barriers and associated difficulties in achieving the 100% market adoption assumed in the technical and economic scenarios.

The initial step was to assess the long-term market adoption potential for energy efficiency technologies. Due to the wide variety of measures across multiple end uses, GDS employed varied measure and end use-specific ultimate adoption rates versus a singular universal market adoption curve. These long-term market adoption estimates were based on aggregated WTP market research across several recent GDS studies. The WTP research included questions to residential homeowners and non-residential facility managers regarding their perceived willingness to purchase and install energy efficient technologies across various end uses and incentive/payback performance levels. One caveat to this approach is that the WTP adoption score is generally a simple function of incentive levels and/or payback performance.

GDS utilized likelihood and WTP data to estimate the long-term market adoption potential for both the maximum and realistic achievable scenarios. Table 2-3 presents the long-term market adoption rates at varied incentive levels used for the residential sector. Most end uses are based on the WTP market research.

TABLE 2-3. RESIDENTIAL LONG-TERM MARKET ADOPTION RATES AT DISCRETE INCENTIVE LEVELS

End Use	0% Incentive	50% Incentive	80% Incentive	100% Incentive
Water Heating	39%	54%	64%	77%
HVAC Equipment	28%	46%	59%	77%
HVAC Shell	32%	51%	60%	75%
Appliances	44%	62%	70%	86%

[4] EM&V encompasses evaluation, measurement and verification activities.

Table 2-4 presents the long-term market adoption rates used in the non-residential sector.

TABLE 2-4. NON-RESIDENTIAL LONG-TERM MARKET ADOPTION RATES AT DISCRETE PAYBACK INTERVALS

End Use	10 Year Payback Period	5 Year Payback Period	3 Year Payback Period	1 Year Payback Period	0 Year Payback Period
Lighting	27%	43%	52%	64%	73%
HVAC	24%	38%	50%	60%	66%
Refrigeration	31%	38%	44%	53%	58%
Water Heat	30%	37%	46%	55%	62%

In the maximum achievable potential scenario, incentives were assumed to represent 100% of the measure cost (0-year payback).

03 RESIDENTIAL ENERGY EFFICIENCY POTENTIAL

3.1 RESULTS

This chapter provides the results for technical, economic, and achievable potential for the residential sector. The chapter breaks down the potential by end use.

Figure 3-1 provides the technical, economic, achievable potential results for the 3-year, 5-year, and 15-year timeframes. The cumulative annual 3-year technical potential is 10% of the residential forecasted sales, and the economic potential is 7% of forecasted sales. The cumulative annual 3-year achievable potential is 4%, as a percentage of forecasted residential sales. Over the duration of the study timeframe the technical potential rises to 36%, and the economic potential rises to 23% of forecasted sales. The achievable potential rises to 14% of forecasted sales. The gap between economic potential and achievable potential represents market barriers to prospective program participants, both financial and non-financial, to achieving the full amount of economic potential.

FIGURE 3-1. RESIDENTIAL CUMULATIVE ANNUAL ENERGY SAVINGS SUMMARY

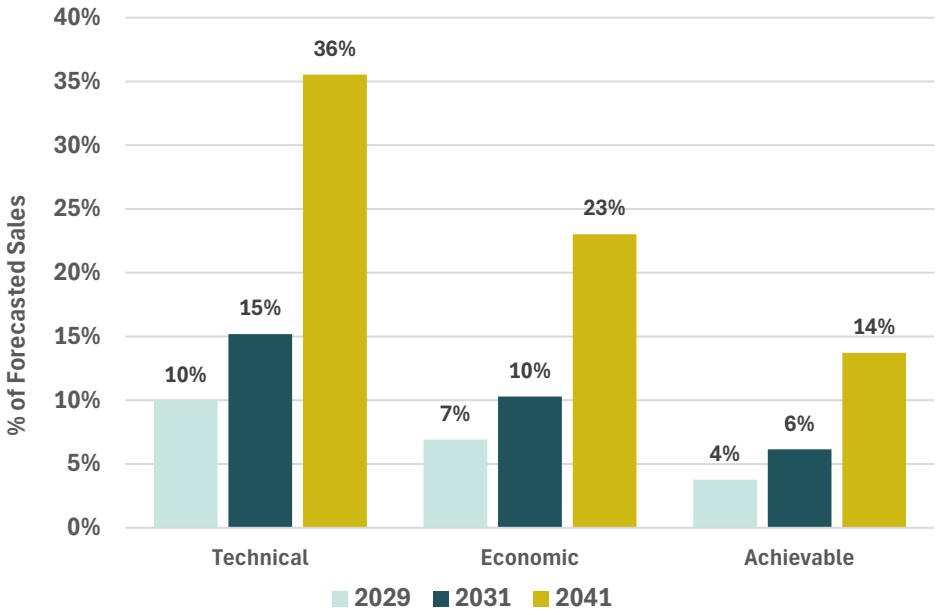


Table 3-1 provides the 15-year residential energy, summer demand, and winter demand potential.

TABLE 3-1. 15-YEAR SUMMARY RESULTS FOR CUMULATIVE RESIDENTIAL ENERGY AND DEMAND SAVINGS

Potential Savings	MWh	Summer MW	Winter MW
Technical	524,783	144.2	101.4
Economic	339,999	75.8	85.0
Achievable	202,616	42.3	47.4

Table 3-2 provides 1-, 2-, 3-, 5-, and 15-yr estimates of cumulative annual technical, economic, and achievable potential for energy.

TABLE 3-2. RESIDENTIAL CUMULATIVE ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

Energy (MWh)	2027	2028	2029	2031	2041
Technical	61,986	101,958	140,967	216,778	524,783
Economic	47,386	73,069	98,107	146,894	339,999
Achievable	13,706	31,325	53,449	87,786	202,616
Energy Savings (as % of Forecast)					
Technical	4%	7%	9%	15%	36%
Economic	3%	5%	7%	10%	23%
Achievable	1%	2%	4%	6%	14%

3.1.1 Technical Potential

Table 3-3 provides 1-, 2-, 3-, 5-, and 15-yr cumulative annual technical potential estimates for energy by end use for Big Rivers.

TABLE 3-3. RESIDENTIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL MWH) TECHNICAL POTENTIAL BY END USE

End Use	2027	2028	2029	2031	2041
Appliances	4,907	9,764	14,569	24,020	55,487
Behavioral	22,826	24,290	25,746	28,634	29,359
HVAC Equipment	7,388	14,711	21,946	36,148	102,872
Lighting	1,636	3,269	4,656	7,304	17,926
Pool/Pump	686	1,370	2,053	3,413	6,720
New Construction	668	1,314	1,919	3,009	6,635
Plug Load	2,542	5,081	7,611	12,651	37,520
Shell	15,258	30,097	44,529	72,209	189,562
Water Heating	6,015	11,939	17,757	29,089	77,806
Cross-Cutting	61	121	182	302	895
Total	**61,986**	**101,958**	**140,967**	**216,778**	**524,783**

Table 3-4 provides 1-, 2-, 3-, 5-, and 15-yr cumulative annual technical potential estimates for summer demand by end use for Big Rivers.

TABLE 3-4. RESIDENTIAL ELECTRIC DEMAND (CUMULATIVE ANNUAL MW) TECHNICAL POTENTIAL BY END USE

End Use	2027	2028	2029	2031	2041
Appliances	0.64	1.28	1.91	3.14	7.38
Behavioral	2.61	2.77	2.94	3.27	3.35
HVAC Equipment	4.14	8.24	12.30	20.26	57.74
Lighting	0.15	0.29	0.44	0.72	1.79
Pool/Pump	0.31	0.61	0.92	1.53	2.20
New Construction	0.12	0.23	0.34	0.53	1.17
Plug Load	0.30	0.60	0.90	1.50	4.45
Shell	4.29	8.47	12.53	20.32	53.35
Water Heating	0.90	1.80	2.68	4.43	12.65

End Use	2027	2028	2029	2031	2041
Cross-Cutting	0.01	0.01	0.02	0.03	0.10
Total	**13.5**	**24.3**	**35.0**	**55.7**	**144.2**

3.1.2 Economic Potential

Table 3-5 provides 1-, 2-, 3-, 5-, and 15-yr cumulative annual economic potential estimates for energy by end use for Big Rivers.

TABLE 3-5. RESIDENTIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL MWH) ECONOMIC POTENTIAL BY END USE

End Use	2027	2028	2029	2031	2041
Appliances	3,233	6,463	9,688	16,121	35,860
Behavioral	22,826	24,290	25,746	28,634	29,359
HVAC Equipment	5,140	10,240	15,285	25,205	72,127
Lighting	1,636	3,269	4,656	7,304	17,926
Pool/Pump	250	499	747	1,239	3,639
New Construction	668	1,314	1,919	3,009	6,635
Plug Load	1,305	2,608	3,907	6,494	19,260
Shell	6,369	12,564	18,588	30,143	79,132
Water Heating	5,899	11,699	17,388	28,442	75,165
Cross-Cutting	61	121	182	302	895
Total	**47,386**	**73,069**	**98,107**	**146,894**	**339,999**

Table 3-6 provides 1-, 2-, 3-, 5-, and 15-yr cumulative annual economic potential estimates for summer demand by end use for Big Rivers.

TABLE 3-6. RESIDENTIAL ELECTRIC DEMAND (CUMULATIVE ANNUAL MW) ECONOMIC POTENTIAL BY END USE

End Use	2027	2028	2029	2031	2041
Appliances	0.43	0.86	1.29	2.14	4.84
Behavioral	2.61	2.77	2.94	3.27	3.35
HVAC Equipment	1.91	3.82	5.70	9.43	27.31
Lighting	0.15	0.29	0.44	0.72	1.79
Pool/Pump	0.00	0.01	0.01	0.02	0.05
New Construction	0.12	0.23	0.34	0.53	1.17
Plug Load	0.15	0.29	0.44	0.73	2.16
Shell	1.80	3.54	5.24	8.50	22.32
Water Heating	0.91	1.81	2.70	4.46	12.69
Cross-Cutting	0.01	0.01	0.02	0.03	0.10
Total	**8.1**	**13.6**	**19.1**	**29.8**	**75.8**

3.1.3 Achievable Potential

Achievable potential is the amount of energy that can realistically be saved given various market barriers. Achievable potential considers real-world barriers to encouraging end users to adopt efficiency measures; the non-measure costs of delivering programs (for administration, marketing, analysis, and EM&V); and the capability of programs and

administrators to boost program activity over time. Therefore, achievable potential is an estimate of how much economic potential can be achieved by program administrators.

Table 3-7 provides 1-, 2-, 3-, 5-, and 15-yr cumulative annual achievable potential estimates for energy by end use for Big Rivers.

TABLE 3-7. RESIDENTIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL MWH) ACHIEVABLE POTENTIAL BY END USE

End Use	2027	2028	2029	2031	2041
Appliances	1,968	3,965	6,012	10,168	23,093
Behavioral	1,722	7,164	16,762	25,964	29,359
HVAC Equipment	2,106	4,257	6,488	11,022	32,854
Lighting	1,174	2,346	3,514	5,659	14,891
Pool/Pump	23	57	111	246	922
New Construction	353	695	1,015	1,591	3,509
Plug Load	819	1,636	2,451	4,074	12,083
Shell	2,991	5,957	8,899	14,707	42,401
Water Heating	2,513	5,170	8,079	14,161	42,928
Cross-Cutting	39	78	117	194	576
Total	**13,706**	**31,325**	**53,449**	**87,786**	**202,616**

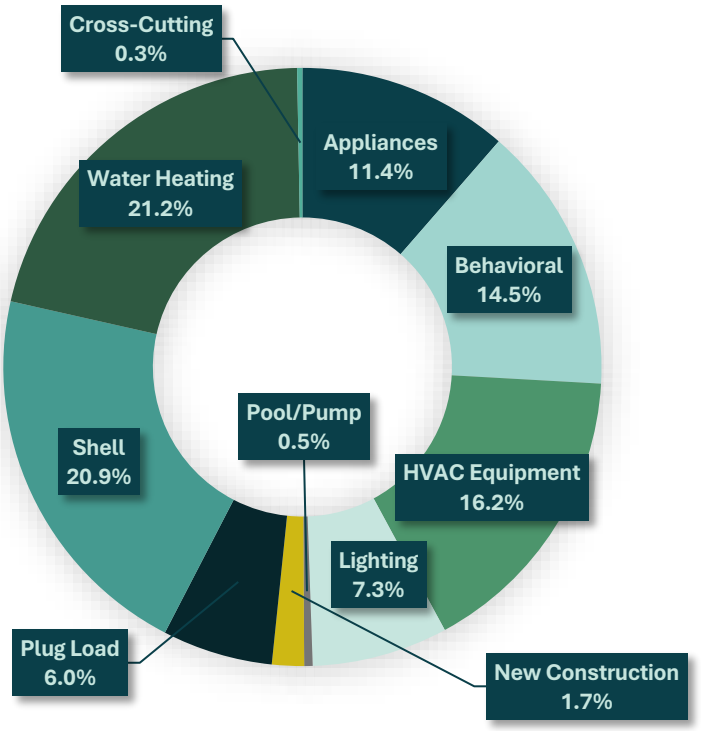
Table 3-8 provides 1-, 2-, 3-, 5-, and 15-yr cumulative annual achievable potential estimates for summer demand by end use for Big Rivers.

TABLE 3-8. RESIDENTIAL ELECTRIC DEMAND (CUMULATIVE ANNUAL MW) ACHIEVABLE POTENTIAL BY END USE

End Use	2027	2028	2029	2031	2041
Appliances	0.27	0.53	0.81	1.37	3.17
Behavioral	0.20	0.82	1.91	2.96	3.35
HVAC Equipment	0.87	1.75	2.65	4.43	13.09
Lighting	0.11	0.21	0.32	0.53	1.52
Pool/Pump	0.00	0.00	0.00	0.01	0.02
New Construction	0.06	0.12	0.18	0.28	0.62
Plug Load	0.09	0.18	0.28	0.46	1.36
Shell	0.86	1.71	2.55	4.21	12.14
Water Heating	0.46	0.92	1.39	2.34	6.92
Cross-Cutting	0.00	0.01	0.01	0.02	0.07
Total	**2.9**	**6.3**	**10.1**	**16.6**	**42.3**

Figure 3-2 provides a graphical representation of the 15-yr cumulative annual achievable potential results by end use.

FIGURE 3-2. RESIDENTIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL GWH) ACHIEVABLE POTENTIAL BY END USE



04 NON-RESIDENTIAL ENERGY EFFICIENCY POTENTIAL

4.1 RESULTS

This chapter provides the results for technical, economic, and achievable potential for the non-residential sector. The chapter breaks down the potential by end use.

Figure 4-1 provides the technical, economic, achievable potential results for the 3-year, 5-year, and 15-year timeframes. The cumulative annual 3-year technical potential is 9% of the non-residential forecasted sales, and the economic potential is 7% of forecasted sales. The cumulative annual 3-year achievable potential is 4% as a percentage of forecasted non-residential sales. Over the duration of the study timeframe the technical potential rises to 32%, and the economic potential rises to 24% of forecasted sales. The achievable potential rises to 14% of forecasted sales. The gap between economic potential and achievable potential represents market barriers to prospective program participants, both financial and non-financial, to achieving the full amount of economic potential.

FIGURE 4-1. NON-RESIDENTIAL CUMULATIVE ANNUAL ENERGY SAVINGS SUMMARY

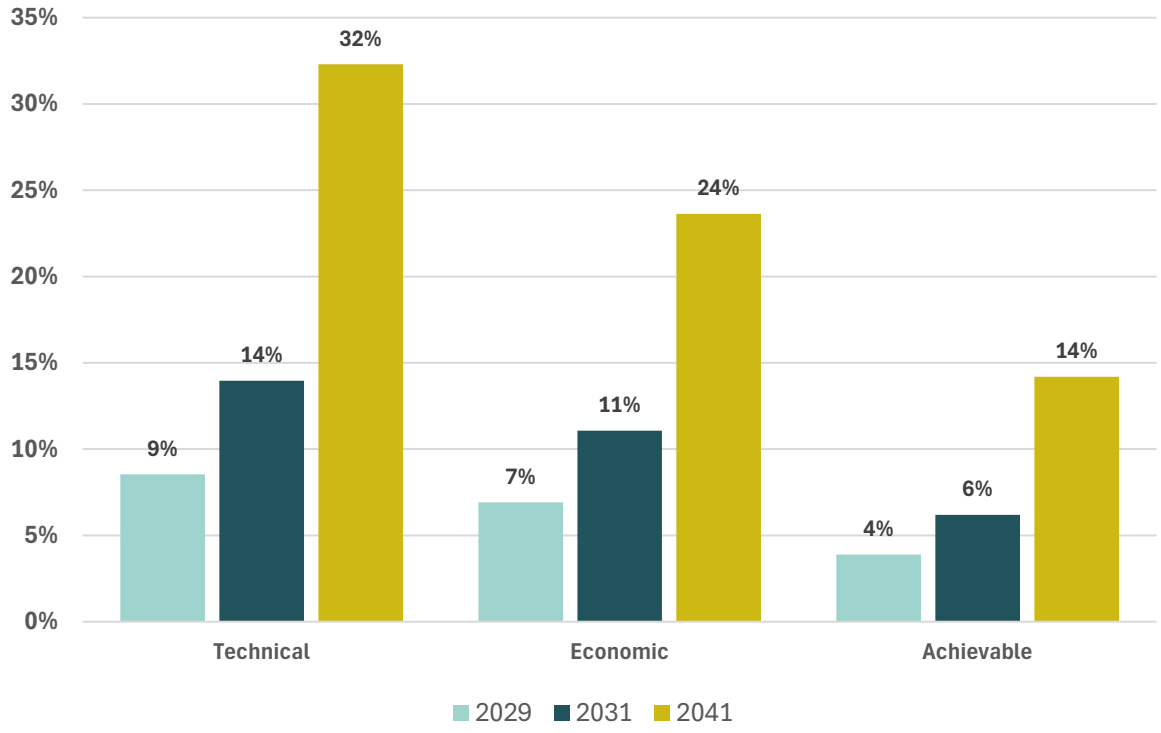


Table 4-1 provides the 15-year non-residential energy, summer demand, and winter demand potential.

TABLE 4-1. 15-YEAR SUMMARY RESULTS FOR CUMULATIVE NON-RESIDENTIAL ENERGY AND DEMAND SAVINGS

Potential	MWh	Summer MW	Winter MW
Technical	267,889	44.6	29.8
Economic	195,957	30.6	22.7
Achievable	117,712	12.3	9.5

Table 4-2 provides 1-, 2-, 3-, 5-, and 15-yr estimates of cumulative annual technical, economic, and achievable potential for energy.

TABLE 4-2. NON-RESIDENTIAL CUMULATIVE ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY (MWH)

Energy (MWh)	2027	2028	2029	2031	2041
Technical	23,047	45,021	66,602	109,693	267,889
Economic	19,426	37,108	54,006	86,927	195,957
Achievable	10,887	20,904	30,350	48,623	117,712
Energy Savings (as % of Forecast)					
Technical	3%	6%	9%	14%	32%
Economic	3%	5%	7%	11%	24%
Achievable	1%	3%	4%	6%	14%

4.1.1 Technical Potential

Table 4-3 provides 1-, 2-, 3-, 5-, and 15-yr cumulative annual technical potential estimates for energy by end use for Big Rivers.

TABLE 4-3. NON-RESIDENTIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL MWH) TECHNICAL POTENTIAL BY END USE

End Use	2027	2028	2029	2031	2041
Behavioral	0	0	0	0	0
Compressed Air	150	309	471	792	1,664
Cooking	312	625	937	1,561	4,033
Cooling	2,223	4,629	7,150	12,283	29,450
Exterior Lighting	776	1,442	1,993	2,775	3,376
Heating	101	203	304	507	1,522
Water Heating	219	425	621	990	2,478
Interior Lighting	3,156	6,573	10,100	16,943	33,231
Miscellaneous	663	1,365	2,167	4,072	12,704
Motors	572	1,156	1,748	2,944	8,404
Office Loads	1,027	2,215	3,542	6,424	14,283
Refrigeration	2,640	5,515	8,556	14,716	27,675
Ventilation	544	1,065	1,545	2,347	3,519
Whole Building	597	1,426	2,323	4,239	16,182
Whole Building HVAC	2,680	6,022	9,766	18,176	63,340
Whole Building NC	5,403	7,939	9,060	10,175	20,360

End Use	2027	2028	2029	2031	2041
Industrial Compressed Air	127	265	410	705	1,660
Industrial HVAC	178	369	564	959	2,662
Industrial Interior Lighting	563	1,149	1,710	2,658	3,985
Industrial Motors	499	1,033	1,582	2,695	7,441
Industrial Process Heat	94	200	312	547	1,343
Industrial Process Refrigeration	113	234	357	606	1,701
Industrial Process Other	156	322	491	831	1,791
Industrial Whole Building	229	490	805	1,575	4,517
Industrial Water & Wastewater	22	47	79	162	547
Agriculture Motors	0.37	0.76	1.15	1.94	5.37
Agriculture Refrigeration	0.10	0.20	0.30	0.50	1.39
Agriculture Interior Lighting	1.23	2.53	3.85	6.31	10.97
Agriculture Ventilation	0.29	0.58	0.87	1.46	2.91
Agriculture HVAC	0.05	0.10	0.14	0.24	0.55
Total	**23,047**	**45,021**	**66,602**	**109,693**	**267,889**

4.1.2 Economic Potential

Table 4-5 provides 1-, 2-, 3-, 5-, and 15-yr cumulative annual economic potential estimates for energy by end use for Big Rivers.

TABLE 4-5 NON-RESIDENTIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL MWH) ECONOMIC POTENTIAL BY END USE

End Use	2027	2028	2029	2031	2041
Behavioral	0	0	0	0	0
Compressed Air	98	206	319	541	1,064
Cooking	296	592	889	1,481	3,841
Cooling	1,415	2,958	4,594	7,933	16,934
Exterior Lighting	776	1,442	1,993	2,775	3,376
Heating	72	144	217	361	1,083
Water Heating	197	382	557	883	2,263
Interior Lighting	3,147	6,557	10,080	16,921	33,219
Miscellaneous	604	1,244	1,982	3,762	11,992
Motors	572	1,156	1,749	2,945	8,406
Office Loads	994	2,152	3,451	6,278	14,041
Refrigeration	2,148	4,477	6,936	11,927	22,484
Ventilation	538	1,051	1,522	2,301	3,366
Whole Building	476	1,171	1,923	3,550	16,263
Whole Building HVAC	761	1,644	2,612	4,692	12,280
Whole Building NC	5,403	7,939	9,060	10,175	20,360
Industrial Compressed Air	127	265	410	705	1,660
Industrial HVAC	178	369	564	959	2,662
Industrial Interior Lighting	563	1,149	1,710	2,658	3,985
Industrial Motors	499	1,033	1,582	2,695	7,441

End Use	2027	2028	2029	2031	2041
Industrial Process Heat	94	200	312	547	1,343
Industrial Process Refrigeration	113	234	357	606	1,701
Industrial Process Other	156	322	491	831	1,791
Industrial Whole Building	173	369	611	1,231	3,833
Industrial Water & Wastewater	22	47	79	162	547
Agriculture Motors	0.37	0.76	1.15	1.94	5.37
Agriculture Refrigeration	0.10	0.20	0.30	0.50	1.39
Agriculture Interior Lighting	1.23	2.53	3.85	6.31	10.97
Agriculture Ventilation	0.29	0.58	0.87	1.46	2.91
Agriculture HVAC	0.05	01.0	0.14	0.24	0.55
Total	**19,426**	**37,108**	**54,006**	**86,927**	**195,957**

4.1.3 Achievable Potential

Achievable potential is the amount of energy that can realistically be saved given various market barriers. Achievable potential considers real-world barriers to encouraging end users to adopt efficiency measures; the non-measure costs of delivering programs (for administration, marketing, analysis, and EM&V); and the capability of programs and administrators to boost program activity over time. Therefore, achievable potential is an estimate of how much economic potential can be achieved by program administrators.

Table 4-7 provides 1-, 2-, 3-, 5-, and 15-yr cumulative annual achievable potential estimates for energy by end use for Big Rivers.

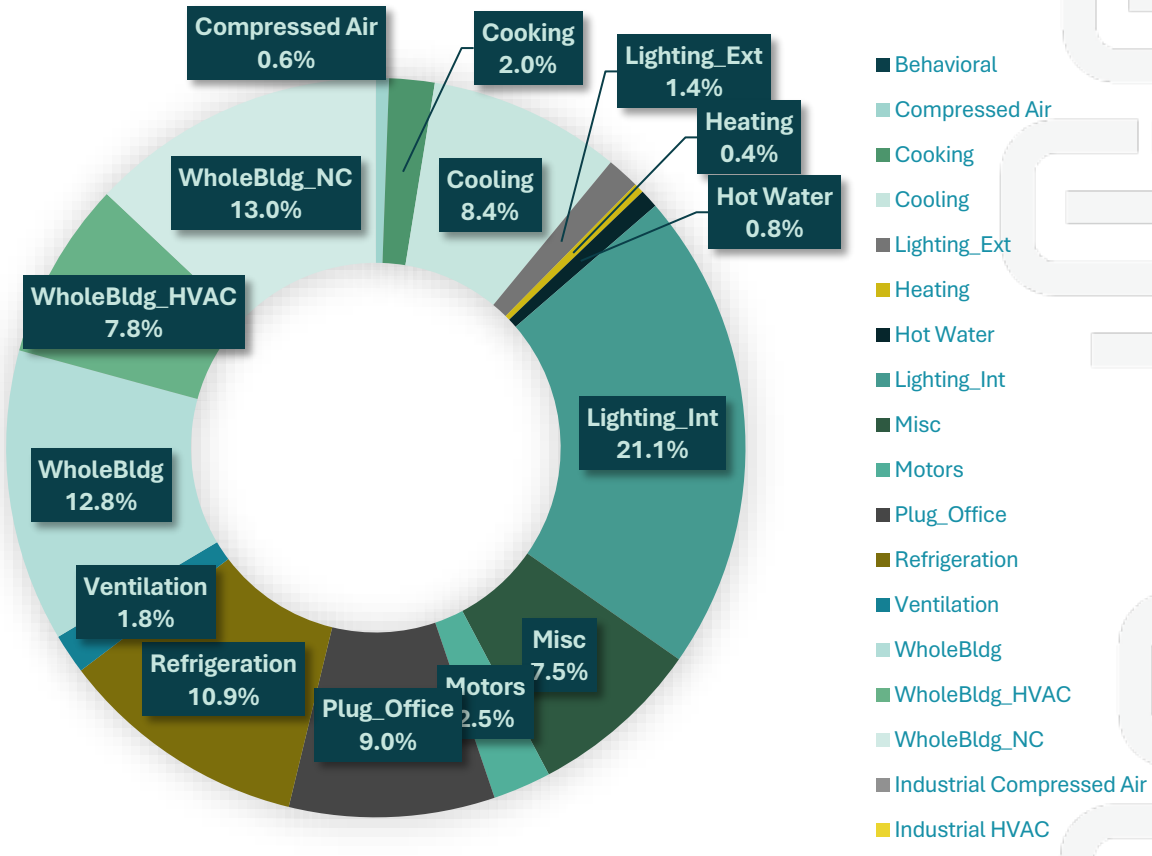
TABLE 4-7 NON-RESIDENTIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL MWH) ACHIEVABLE POTENTIAL BY END USE

End Use	2027	2028	2029	2031	2041
Behavioral	0	0	0	0	0
Compressed Air	65	131	196	317	588
Cooking	104	221	348	629	2,028
Cooling	748	1,563	2,418	4,111	8,609
Exterior Lighting	374	683	930	1,269	1,460
Heating	8.4	19	33	72	450
Water Heating	50	95	137	221	839
Interior Lighting	2,258	4,562	6,833	11,088	21,555
Miscellaneous	290	609	967	1,925	7,726
Motors	54	127	217	445	2,606
Office Loads	614	1,343	2,173	4,007	9,208
Refrigeration	1,193	2,458	3,750	6,211	11,175
Ventilation	332	635	902	1,318	1,793
Whole Building	350	867	1,433	2,682	13,091
Whole Building HVAC	522	1,118	1,761	3,109	7,979
Whole Building NC	2,966	4,473	5,181	5,924	13,277
Industrial Compressed Air	46	103	170	322	1,006
Industrial HVAC	52	117	193	377	1,453

End Use	2027	2028	2029	2031	2041
Industrial Interior Lighting	475	922	1,312	1,908	2,570
Industrial Motors	148	334	552	1,074	4,075
Industrial Process Heat	42	93	151	282	795
Industrial Process Refrigeration	31	71	118	231	922
Industrial Process Other	44	99	164	320	1,119
Industrial Whole Building	107	229	359	682	2,996
Industrial Water & Wastewater	14	30	47	95	378
Agriculture Motors	0.10	0.21	0.35	0.67	2.58
Agriculture Refrigeration	0.03	0.06	0.09	0.17	0.59
Agriculture Interior Lighting	0.82	1.65	2.46	3.93	6.66
Agriculture Ventilation	0.06	0.14	0.23	0.46	1.66
Agriculture HVAC	0.01	0.02	0.03	0.06	0.28
Total	**10,887**	**20,904**	**30,350**	**48,623**	**117,712**

Figure 4-2 provides a graphical representation of the 15-yr cumulative annual achievable potential results by end use.

FIGURE 4-2. NON-RESIDENTIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL GWH) ACHIEVABLE POTENTIAL BY END USE



05 ENERGY EFFICIENCY PROGRAM POTENTIAL

This study estimates potential savings from a portfolio of energy efficiency programs based on specified funding levels, including $0.5 million, $1.5 million, and $2.5 million annual incentive budget scenarios. All program scenarios remain cost-effective under the TRC test. It is important to note that the program potential results represent a subset of achievable potential and are intended to illustrate what could be attained under specific funding levels. These results are not intended to represent specific future program designs or approved budgets.

5.1 ENERGY EFFICIENCY PROGRAM POTENTIAL SUMMARY

Figure 1-1 provides a summary of the 15-year program potential (three funding scenarios) in comparison to the technical, economic, and achievable potential in the Big Rivers service territory.

FIGURE 5-1. ELECTRIC EFFICIENCY POTENTIAL SAVINGS SUMMARY

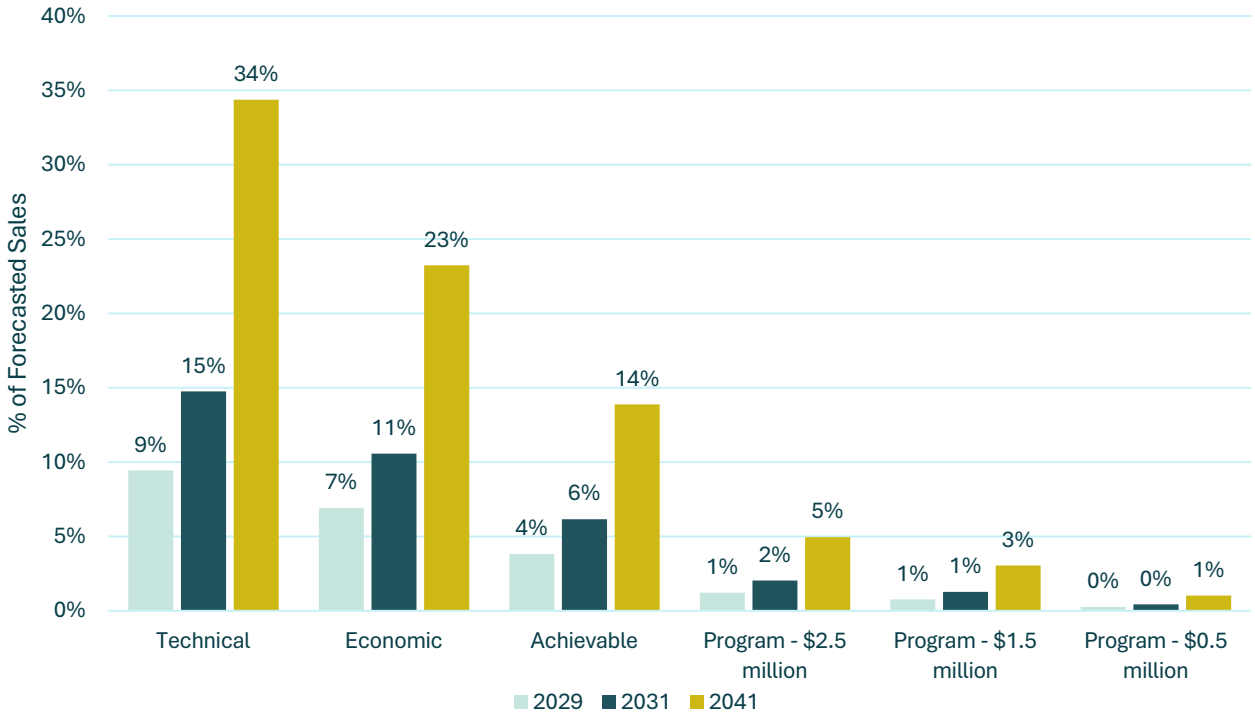


Table 5-1 provides a summary of the 15-year energy, summer demand, and winter demand potential.

TABLE 5-1. 15-YEAR SUMMARY CUMULATIVE RESULTS FOR ENERGY AND DEMAND

Potential Savings	MWh	Summer MW	Winter MW
Technical	792,672	188.7	131.2
Economic	535,956	106.4	107.8
Achievable	320,328	54.6	56.9
Program - $2.5 million	114,239	23.7	21.7
Program - $1.5 million	70,317	14.3	11.8
Program - $0.5 million	23,753	4.5	3.7

Based on the results of the achievable potential analysis, Big Rivers chose to evaluate the energy efficiency programs listed in Table 5-2 as part of its DSM study.

TABLE 5-2. LIST OF PROGRAMS EVALUATED IN THE STUDY

Sector	Program Name
Residential	Energy Star Refrigerator / Refrigerator Recycle Program
Residential	Energy Star Clothes Washer / Dryer Program
Residential	Heat Pump Program
Residential	Ductless Heat Pump Program
Residential	Smart Thermostat Program
Residential	New Construction Program
Commercial/Industrial	C&I Custom Program

These programs represent the end uses and equipment that hold significant opportunity for cost-effective savings in the residential and commercial/industrial sector[5]. 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 three different funding scenarios: a $2.5 million incentive scenario, a $1.5 million incentive scenario, and a $0.5 million incentive scenario. In each case, the residential and non-residential sectors were allocated 50% of the incentive budget.

Table 5-3 shows the net present value (NPV) benefits, NPV costs, and benefit-cost ratios for the three program potential scenarios examined in this study. The overall cost-effectiveness ratios have decreased since the last study but still indicate that the program potential scenarios are cost-effective overall. There are several reasons for decreased cost-effectiveness including reduced opportunity for low-cost lighting savings due to changing market conditions and the effect of standards. The avoided capacity costs used to value demand savings also decreased since the last study.

TABLE 5-3. PROGRAM POTENTIAL COST-EFFECTIVENESS (TRC TEST)

Potential	NPV Benefits	NPV Costs	NPV Savings (Benefits - Costs)	TRC Test Ratio
Program - $2.5 million	$82.3	$42.4	$40.0	1.9
Program - $1.5 million	$49.0	$25.4	$23.6	1.9
Program - $0.5 million	$16.0	$8.5	$7.5	1.9

Figure 5-2 provides the 3-year, 5-year, and 15-year program potential for each funding scenario. The $2.5 million funding scenario program potential is 1.2% of forecast sales over the 3-year timeframe and rises to 5.0% across the 15-year timeframe. The $1.5 million funding scenario program potential is 0.8% of forecasted sales over the 3-year

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

timeframe and rises to 3.0% across the 15-year timeframe. The $0.5 million funding scenario program potential is 0.3% of forecast sales over the 3-year timeframe and rises to 1.0% across the 15-year timeframe.

FIGURE 5-2. ELECTRIC ENERGY CUMULATIVE ANNUAL PROGRAM POTENTIAL

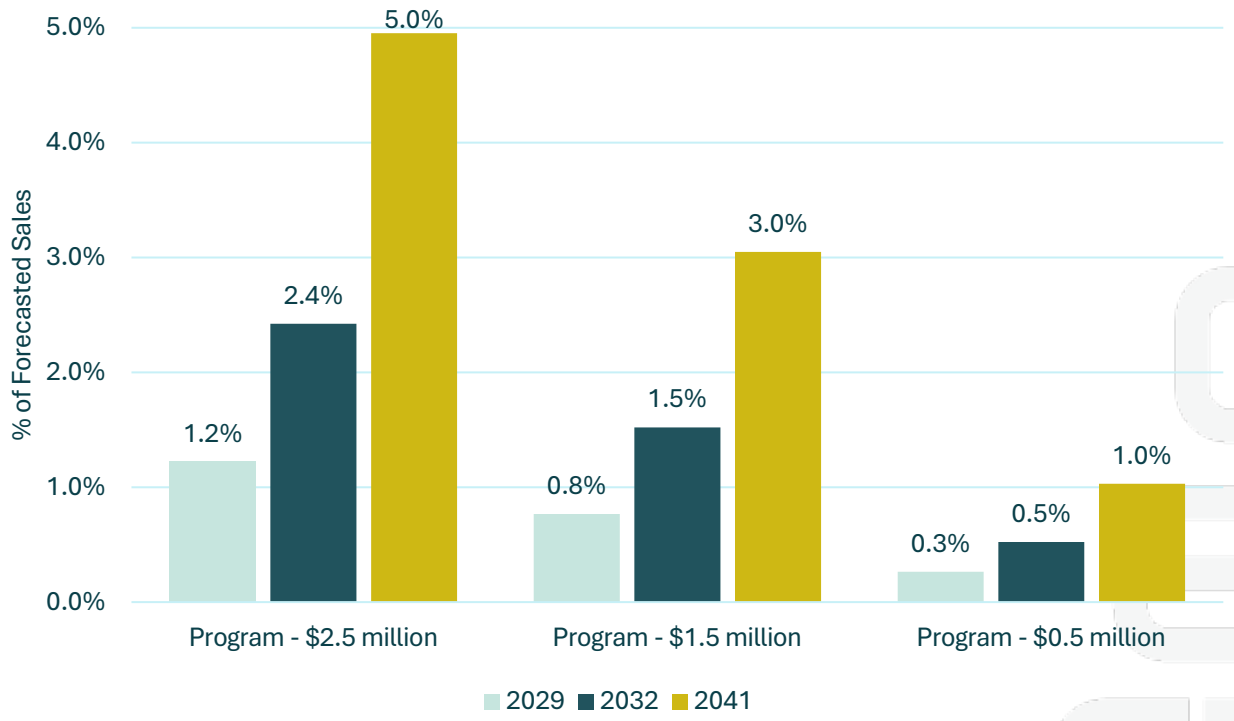


Table 5-2 provides 1-, 2-, 3-, 5-, and 15-year estimates of cumulative annual program potential for energy, summer peak demand, and winter peak demand. By 2029, the program potential is nearly 27,000 MWh, 17,000 MWh, and 6,000 MWh for the $2.5 million, $1.5 million, and $0.5 million program potential scenarios, respectively. Summer peak demand program potential is 4.5 MW, 3.0 MW, and 0.9 MW by 2029 for the respective $2.5 million, $1.5 million, and $0.5 million program potential scenarios.

TABLE 5-2. CUMULATIVE PROGRAM POTENTIAL SAVINGS SUMMARY

	2027	2028	2029	2031	2041
Annual Energy (MWh)					
Program - $2.5 million	8,734	17,723	26,883	45,066	114,239
Program - $1.5 million	5,479	11,115	16,854	28,272	70,317
Program - $0.5 million	1,887	3,827	5,801	9,731	23,753
Summer Peak Demand (MW)					
Program - $2.5 million	0.9	2.7	4.5	8.1	23.7
Program - $1.5 million	0.6	1.8	3.0	5.4	14.3
Program - $0.5 million	0.2	0.6	0.9	1.7	4.5
Winter Peak Demand (MW)					
Program - $2.5 million	1.6	3.3	4.9	8.3	21.7
Program - $1.5 million	0.9	1.8	2.7	4.5	11.8
Program - $0.5 million	0.3	0.6	0.9	1.4	3.7

5.2 ENERGY EFFICIENCY PROGRAM POTENTIAL SCENARIOS

The program potential assessment involved six residential programs and one C&I program. Each of these programs was assigned an annual budget. The resulting savings estimated for each program are shown for each of the three incentive scenarios.

Table 5-3 provides a summary of the program potential for the $0.5 million incentive scenario, Table 5-4 provides a summary for the $1.5 million incentive scenario, and Table 5-5 provides a summary for the $2.5 million incentive scenario.

TABLE 5-3. $0.5 MILLION INCENTIVE SCENARIO – MWH SAVINGS BY PROGRAM

Program Name	2027	2028	2029	2031	2041
Refrigerator / Refrigerator Recycle Program	166	331	497	828	1,159
Clothes Washer / Dryer Program	146	293	439	731	2,048
Heat Pump Program	68	135	200	328	952
Ductless Heat Pump Program	107	213	319	530	1,560
Smart Thermostat Program	148	295	443	738	1,623
New Construction Program	123	246	369	615	1,844
C&I Custom Program	1,130	2,314	3,536	5,962	14,567
Total	**1,887**	**3,827**	**5,801**	**9,731**	**23,753**

TABLE 5-4. $1.5 MILLION INCENTIVE SCENARIO – MWH SAVINGS BY PROGRAM

Program Name	2027	2028	2029	2031	2041
Refrigerator / Refrigerator Recycle Program	166	331	497	828	1,159
Clothes Washer / Dryer Program	591	1,181	1,782	3,007	8,810
Heat Pump Program	274	544	811	1,347	4,077
Ductless Heat Pump Program	190	379	567	942	2,774
Smart Thermostat Program	596	1,191	1,798	3,032	7,064
New Construction Program	273	546	792	1,229	2,732
C&I Custom Program	3,390	6,943	10,607	17,887	43,701
Total	**5,480**	**11,115**	**16,854**	**28,272**	**70,317**

TABLE 5-5. $2.5 MILLION INCENTIVE SCENARIO – MWH SAVINGS BY PROGRAM

Program Name	2027	2028	2029	2031	2041
Refrigerator / Refrigerator Recycle Program	166	331	497	828	1,159
Clothes Washer / Dryer Program	813	1,625	2,438	4,063	11,378
Heat Pump Program	823	1,631	2,405	3,954	10,467
Ductless Heat Pump Program	190	379	614	1,083	3,375
Smart Thermostat Program	820	1,639	2,459	4,098	12,293
New Construction Program	273	546	792	1,229	2,732
C&I Custom Program	5,650	11,571	17,678	29,811	72,835
Total	**8,734**	**17,723**	**26,883**	**45,066**	**114,239**

Big Rivers and the Member Cooperatives will continue to seek and evaluate new technologies and opportunities to benefit the 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 spending to other programs and sectors.

Residential Refrigerator / Refrigerator Recycle Program

The Refrigerator Recycle Program promotes the installation of higher efficiency refrigerators through the removal and recycling of older, more inefficient units. Incentives offered through this program are designed to encourage the retirement of outdated units that contribute to higher energy consumption and peak demand levels.

Residential Clothes Washer / Dryer Program

The Residential Clothes Washer / Dryer Program promotes installation of higher efficiency clothes washers and dryers. Incentives are provided to offset the higher upfront cost of qualifying efficient washers and dryers and to encourage the replacement of standard efficiency appliances.

Residential Heat Pump Program

The Residential Heat Pump Program promotes increased adoption of high-efficiency heat pump systems for space heating and cooling. Incentives are designed to reduce the cost of replacing less efficient heating and cooling systems with qualifying heat pumps.

Residential Ductless Heat Pump Program

The Residential Ductless Heat Pump Program promotes increased use of high-efficiency ductless heat pump systems, which can be beneficial in homes without existing ductwork or in zones requiring supplemental heating or cooling. Incentives encourage adoption of these systems by reducing upfront costs.

Residential Smart Thermostat Program

The Residential Smart Thermostat Program promotes increased use of smart thermostats that enable automated temperature control, scheduling, and remote connectivity features. Program incentives support the adoption of qualifying devices that help customers optimize usage through reducing energy consumption during peak periods.

Residential New Construction Program

This Residential New Construction Program provides incentives to homeowners and builders to use energy efficient building standards. Incentives through this program are intended to encourage the incorporation of energy efficient building envelopes, equipment, and systems at the time of construction resulting in long-term energy savings.

Commercial and Industrial Custom Program

The Custom Program promotes the implementation of customized energy-saving projects at any qualifying customer facilities. Incentives (typically on a $/kWh or kW saved basis) promoted through this program serve to reduce the cost of implementing energy-reducing projects and upgrading to high-efficiency equipment. Due to the nature of a custom EE program, a wide variety of projects are eligible across all electric end uses where savings can be reasonably quantified.

06 DEMAND RESPONSE METHODOLOGY

The Market Potential Study focused on energy efficiency programs but also included an evaluation of possible demand response programs in Big Rivers' territory. This section provides an overview of the results of the demand response analysis. This section provides an overview of the demand response potential methodology. Summary results of the demand response analysis are provided in Section 7.

6.1 DEFINITION OF DEMAND RESPONSE

According to the Federal Energy Regulatory Commission (FERC), demand response is defined as changes in electric usage by demand-side resources from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized. FERC's definition of demand response conforms to the North American Electric Reliability Corporation (NERC) definition developed by a consortium of utilities and end users.

This study uses the FERC definition of demand response so that all potential DR, including rate options, are identified. Big Rivers' integrated resource planning team will analyze and adjust as necessary the identified DR potential for how DR potential will be used to construct alternative resource plans.

6.2 DEMAND RESPONSE PROGRAM OPTIONS

Big Rivers does not currently operate any demand response programs. Table 6-1 provides a brief description of the demand response program options considered and identifies the eligible customer segment for each demand response program that was considered in this study.

TABLE 6-1. DEMAND RESPONSE PROGRAM OPTIONS

Demand Response Program Option	Description	Eligible Markets
Direct Load Control (DLC) Air Conditioning Switch	The compressor of the air conditioner is remotely shut off (cycled) by the system operator for periods that may range from 7 ½ to 15 minutes during every 30-minute period (i.e., 25%-50% duty cycle). Controlled via load control switch. Participant cannot override control.	Residential, Small C&I
DLC Thermostat	The air conditioner or electric heating is remotely shut off (cycled) by the system operator for periods that may range from 7 ½ to 15 minutes during every 30-minute period (i.e., 25%-50% duty cycle). Controlled via smart thermostat. Participant has option to override control.	Residential, Small C&I
DLC Water Heater Switch	The water heater is remotely shut off by the system operator using a load control switch for periods normally ranging from 2 to 4 hours using a load control switch.	Residential, Small C&I
DLC Water Heater Grid-Enabled	The grid-enabled water heater is equipped with a smart controller that allows the utility to remotely shut off the water heater for periods normally ranging from 2 to 4 hours.	Residential, Small C&I
DLC Swimming Pool Pump	The swimming pool pump is remotely shut off by the system operator for periods normally ranging from 2 to 4 hours.	Residential

Demand Response Program Option	Description	Eligible Markets
DLC Electric Vehicle	DLC of electric vehicles relies on communication (i.e., "dispatch") signals originating from a utility or aggregator and sent to a vehicle or charger to control charging in a predetermined manner. Can be events-based to control load during a limited number of events in a given time period (season or annually) or use continuous management to control load when the vehicle is connected to the charger.	Residential & Commercial EV Chargers
Electric Vehicle Time-of-Use (TOU)	A special electricity pricing structure designed for EV owners where the price of electricity varies based on the time of day when it is used.	Residential & Commercial EV Chargers
TOU Rate	A retail rate with different prices for usage during different blocks of time. Daily pricing blocks could include on-peak, mid-peak, and off-peak periods.	Residential, Small C&I, Large C&I
Critical Peak Pricing (CPP) Rate	A retail rate in which an extra-high price for electricity is provided during critical periods (e.g. 100 hours) of the year. Prices can be fixed or fluctuate with the market. Market-based prices are typically provided on a day-ahead basis, or an hour-ahead basis.	Residential, Small C&I, Large C&I
Peak Time Rebate	Customers are given a rebate for less consumption during times selected as critical periods.	Residential
Battery Storage	Uses the battery to reduce a home or facility's demand during peak or DR event hours, without requiring the customer to curtail their power. Instead of turning off equipment, the battery discharges power to offset load—or shifts charging to off-peak periods—so the utility sees a drop in grid demand.	Residential & Commercial Customers with Solar
Generators	Allows the utility to turn customer's generator on and off for short periods of time during specific times of the day. The goal of DR is to enable the utility to reduce pressure on the grid and avoid rolling black outs during times of high usage.	Residential
Conservation Voltage Reduction (CVR)	A grid management strategy where the utility temporarily reduces distribution system voltage to lower customer power consumption during peak periods.	Residential, Small C&I, Large C&I
Interruptible Rate	A special tariff offered to large commercial & industrial (C&I) customers where they receive reduced energy or demand charges in exchange for agreeing to curtail a specified amount of load when the utility or grid operator calls an event.	Large C&I
Capacity Bidding	Flexible bidding program offering qualified businesses payments for agreeing to reduce load when an event is called. Participants make monthly nominations and receive capacity payments based on the amount of capacity reduction nominated each month. The amount of capacity nomination can be adjusted on a monthly basis. The program can be Internet-based, providing ready access to program information and ease-of-use. Penalties occur if load nominations are not met. Not all load nominated is necessarily dispatched.	Small C&I, Large C&I

6.3 DEMAND RESPONSE POTENTIAL ASSESSMENT APPROACH OVERVIEW

The analysis of DR, where possible, closely follows the approach outlined for energy efficiency. The framework for assessing the cost-effectiveness of demand response programs is based on A Framework for Evaluating the Cost-Effectiveness of Demand Response, prepared for the National Forum on the National Action Plan (NAPDR) on Demand Response. Additionally, GDS reviewed the National Standard Practice Manual published by the National Efficiency Screening Project. GDS utilized this guide to define avoided ancillary services and energy and/or capacity prices.

The demand response analysis was conducted using the GDS Demand Response Model. The DR Model determines the estimated savings for each demand response program by performing a review of all benefits and costs associated with each program. GDS developed the model such that the value of future programs could be determined and will help facilitate demand response program planning strategies. The model contains approximately 50 required inputs for each program including: expected life, coincident peak ("CP") kW load reductions, proposed rebate levels, program related expenses such as vendor service fees, marketing and evaluation cost and on-going O&M expenses. This model and future program planning features can be used to standardize the cost-effectiveness screening process between Big Rivers departments interested in the deployment of demand response resources.

The TRC Test was used to determine the cost-effectiveness of each demand response program. Benefits are based on energy (including load shifting), transmission and distribution (T&D) infrastructure costs, and avoided generation capacity. Costs include incremental program equipment costs (such as control switches or smart thermostats), fixed program capital costs (such as the cost of a central controller), program administration, marketing and evaluation costs. Incremental equipment program costs are included for both new and replacement units (such as control switches) to account for units that are replaced at the end of their useful life.

6.4 AVOIDED COSTS

Demand response avoided costs are consistent with those utilized in the energy efficiency potential analysis and were provided by Big Rivers. The primary benefit of demand response is avoided generation capacity, resulting from a reduction in the need for new peaking generation capacity. Demand response can produce energy-related benefits. Demand response programs can also potentially delay the construction of new transmission and distribution lines and facilities, which is reflected in avoided T&D costs. If the demand response option is considered "load shifting," such as direct load control of electric water heating, the consumption of energy is shifted from the control period to the period immediately following the period of control. If the program is not considered to be "load shifting" the measure is turned off during peak control hours, and the energy is saved altogether.

6.5 DEMAND RESPONSE PROGRAM ASSUMPTIONS

This section briefly discusses the general assumptions and sources that will be used to complete the demand response potential analysis. All assumptions with sources are included in Appendix D.

Load Reduction: Demand reductions were based on various secondary data sources including evaluation studies, FERC and other industry reports, and other demand response potential studies that conducted primary research. Some programs were calculated based on a per-unit kW demand reduction and other program options were assumed to reduce a percentage of the total facility peak load. These load reductions can be found in Table 6-2.

TABLE 6-2. DEMAND RESPONSE LOAD REDUCTION IMPACTS

Program	Residential Load Reduction (kW)	Non-Residential Load Reduction (kW)
DLC Central AC Switch	0.79 kW (Summer only)	1.65 kW (Summer only)
DLC Thermostat	0.93 kW in Summer; 1.61 kW in Winter	1.95 kW in Summer; 2.54 kW in Winter
DLC Water Heater Switch	0.39 kW in Summer; 0.59 kW in Winter	1.5 kW in Summer; 1.5 kW in Winter
DLC Water Heater Grid-Enabled	0.43 kW in Summer; 0.63 kW in Winter	1.5 kW in Summer; 1.5 kW in Winter
DLC Swimming Pool Pump	0.52 kW (Summer only)	N/A
DLC Electric Vehicle	0.295 kW in Summer; 0.35 kW in Winter	0.02 kW in Summer; 0.03 kW in Winter
Electric Vehicle TOU	0.39 kW in Summer; 0.33 kW in Winter	0.02 kW in Summer; 0.03 kW in Winter
TOU Rate	8.6% of CP Billing Demand in Summer; 3.6% in Winter	2% of CP Billing Demand in Summer; 1% in Winter
CPP Rate	12.8% of CP Billing Demand in Summer; 7.7% in Winter	7.9% of CP Billing Demand in Summer; 6% in Winter
Peak Time Rebate	14% of CP Billing Demand in Summer; 8% in Winter	N/A
Battery Storage	3 kW	11.25 kW
Generators	50% of home's load	N/A
Conservation Voltage Reduction	1.7% of CP Billing Demand	1.7% of CP Billing Demand
Interruptible Rate	N/A	23% of CP Billing Demand
Capacity Bidding	N/A	25% of CP Billing Demand

Useful Life: The useful life of equipment used in demand response programs, such as load control switches, smart thermostats, or batteries, was determined using TRMs and data from manufacturers. This useful life was used to determine when equipment needs to be re-installed in the study after the device has failed, therefore adding a second equipment cost for some participants in the study. GDS used a useful life of 11 years for smart thermostats[6], 10 years for level 2 EV chargers[7], 10 years for battery storage[8], 19 years for generators[9], and 10 years for load switches.[10]

Equipment and Incentive Costs: Equipment costs were included for each new participant. Annual incentives were included either on a per participant, per kW or per kWh basis (noted in Table 6-3). For a few of the programs, the utility is incentivizing the customer by paying for a portion of the equipment cost.

[6] Illinois Technical Reference Manual 2025
[7] US DOE, Costs Associated with Non-Residential EV Supply Equipment, 2015
[8] Tesla Warranty
[9] FEMA
[10] Freeman, Sullivan & Co Cost Effectiveness of CECONY Demand Response Programs 2013

TABLE 6-3. ASSUMED BASE CASE EQUIPMENT AND INCENTIVE COSTS

	DR Program Option	Incentive Costs	Equipment Costs
Residential	DLC Central AC Switch	$31/participant-year + one-time incentive of $28	$230/new participant
	DLC Thermostat	$32/participant-year + one-time incentive of $60	$130/new participant
	DLC Water Heater Switch	$30/participant-year	$330/new participant
	DLC Water Heater Grid-Enabled	$30/participant-year + one-time incentive of $400	$50/new participant
	DLC Swimming Pool Pump	$12/participant-year	$141/new participant
	DLC Electric Vehicle	$39/participant-year + one-time incentive of $155	$0
	Electric Vehicle TOU	$0	$0
	TOU Rate	$0	$0
	CPP Rate	$0	$0
	Peak Time Rebate	$1/kWh saved	$0
	Battery Storage	$400/participant-year	$0 (assume BYOD program)
	Generators	$250/participant-year + one-time incentive of $100	$0
	Conservation Voltage Reduction	$0	$0
Non-Residential	DLC Central AC Switch	$38/participant-year + one-time incentive of $28	$387/new participant
	DLC Thermostat	$54/participant-year + one-time incentive of $88	$102/new participant
	DLC Water Heater Switch	$30/participant-year	$330/new participant
	DLC Water Heater Grid-Enabled	$30/participant-year + one-time incentive of $400	$50/new participant
	DLC Electric Vehicle	$39/participant-year + one-time incentive of $155	$0
	Electric Vehicle TOU	$0	$0
	TOU Rate	$0	$0
	CPP Rate	$0	$0
	Battery Storage	$1500/participant-year	$0 (assume BYOD program)
	Conservation Voltage Reduction	$0	$0
	Interruptible Rate	$8/kW-month	$0
	Capacity Bidding	$80/kW pledged	$0

Eligible Market Size: For direct load control programs, the size of the eligible market was determined by multiplying the forecast of Big Rivers' customers by the saturation of the end use to be controlled. End use saturations were obtained from the 2025 Big Rivers saturation data as well as CBECs for data that was not included in the 2025 saturation data.

Program Adoption Levels: Long-term program adoption levels (or "steady state" participation) represent the enrollment rate once the fully achievable participation has been reached. GDS has reviewed industry data and program adoption levels from several utilities' DR programs.

Customer participation in new demand response programs is assumed to reach the steady state adoption rate over a five-year period. The path to steady state customer participation follows an "S-shaped" curve, in which participation growth accelerates over the first half of the five-year period, and then slows over the second half of the period (Figure 6-1). GDS used other research or potential studies to determine steady state participation rates. Table 6-4 provides the Base Case long-term adoption rates for achievable potential.

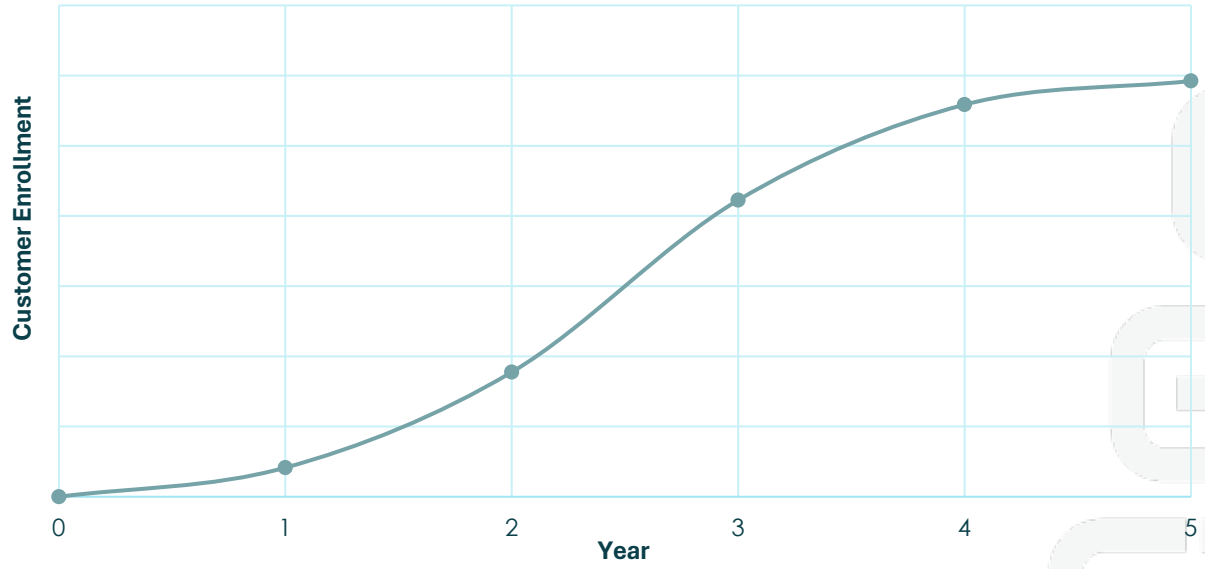


FIGURE 6-1 ILLUSTRATION OF S-SHAPED MARKET ADOPTION CURVE

TABLE 6-4. BASE CASE ADOPTION RATES

	DR Program Option	Steady State Adoption Rate
Residential	DLC Central AC Switch	11.5%
	DLC Thermostat	20%
	DLC Water Heater Switch	20%
	DLC Water Heater Grid-Enabled	10%
	DLC Swimming Pool Pump	20%
	DLC Electric Vehicle	20%
	Electric Vehicle TOU	20%
	TOU Rate	10.2%
	CPP Rate	15%
	Peak Time Rebate	13%
	Battery Storage	50%
	Generators	5%
	Conservation Voltage Reduction	100%
Non-Residential	DLC Central AC Switch	10%
	DLC Thermostat	14%

DR Program Option	Steady State Adoption Rate
DLC Water Heater Switch	20%
DLC Water Heater Grid-Enabled	10%
DLC Electric Vehicle	10%
Electric Vehicle TOU	20%
TOU Rate	16%
CPP Rate	15%
Battery Storage	50%
Conservation Voltage Reduction	100%
Interruptible Rate	19%
Capacity Bidding	21.5%

Double-counting savings from demand response programs that affect the same end uses is a common issue that must be addressed when calculating the demand response savings potential. For example, a customer cannot elect to participate in both DLC programs and rate programs and claim savings from both programs for curtailing the same end use. One cannot save a kW of load in a specific hour more than once. In general, the hierarchy of demand response programs is accounted for by subtracting the number participants in a higher priority program from the eligible market for a lower priority program. Table 6-5 shows the hierarchy for each sector, with 1 being the top priority.

TABLE 6-5. BASE CASE DR HIERARCHY FOR EACH SECTOR

Order	Residential Hierarchy	C&I Hierarchy
1	Direct Load Control	Direct Load Control
2	Peak Time Rebate	Critical Peak Pricing
3	Critical Peak Pricing	Time-of-Use
4	Time-of-Use	Interruptible Rate
5	N/A	Capacity Bidding

6.6 DEMAND RESPONSE PROGRAM POTENTIAL SCENARIOS

Three budget scenarios were analyzed to estimate program potential under funding levels of $0.5 million, $1.5 million, and $2.5 million. Big Rivers identified the highest-priority programs, which were included in these scenarios. The available budget was initially allocated equally across these programs. If a program did not require its full allocation to reach the achievable potential, any remaining funds were redistributed among the other programs that had not yet reached their total achievable potential level. To align program costs with the budget scenarios, program impacts were scaled down by reducing the number of program participants until the target budget was reached.

07 DEMAND RESPONSE POTENTIAL

Consistent with the energy efficiency evaluation, DR programs are primarily evaluated based on the TRC test, but Utility Cost Test (UCT) and Participant Cost Test (PCT) were also calculated. Table 7-1 provides the results of the TRC test for achievable potential.

TABLE 7-1. DEMAND RESPONSE PROGRAMS ACHIEVABLE POTENTIAL COST-EFFECTIVENESS RESULTS

Sector	Program	TRC
Residential	DLC AC Switch	1.34
	DLC Thermostat	1.87
	DLC Water Heater Switch	0.69
	DLC Water Heater Grid-Enabled	0.49
	DLC Swimming Pool Pump	1.00
	DLC Electric Vehicle	0.41
	Electric Vehicle TOU	2.74
	Time-of-Use Rate	2.84
	Critical Peak Pricing Rate	6.36
	Peak Time Rebate	1.63
	Battery Storage	0.25
	Generators	0.51
	CVR	6.82
C&I	DLC AC Switch	2.27
	DLC Thermostat	2.73
	DLC Water Heater Switch	3.42
	DLC Water Heater Grid-Enabled	1.67
	DLC Electric Vehicle	0.00
	Electric Vehicle TOU	0.00
	Time-of-Use Rate	2.14
	Critical Peak Pricing Rate	9.50
	Battery Storage	0.16
	Capacity Bidding	0.95
	Interruptible Rate	1.38
	CVR	10.63

Table 7-2 provides 1-, 2-, 3-, 5-, and 15-yr estimates of cumulative annual technical, economic, and achievable potential for energy.

TABLE 7-2. CUMULATIVE ANNUAL DEMAND RESPONSE MW POTENTIAL SUMMARY

	2027	2028	2029	2031	2041
Technical	650	593	516	460	416
Economic	369	351	322	299	278
Achievable (Summer)	12	36	69	93	93

Similar to the energy efficiency analysis, achievable potential was calculated based on estimates of the amount of demand response that could be realistically achieved over the study period. Program potential was then considered at three different funding scenarios: a $2.5 million scenario, a $1.5 million scenario, and a $0.5 million scenario. Summer demand potential is shown in Figure 7-1 in 2029, 2031, and 2041. Table 7-3 shows the summer and winter demand potential in 2041.

FIGURE 7-1. DEMAND RESPONSE CUMULATIVE POTENTIAL SAVINGS SUMMARY

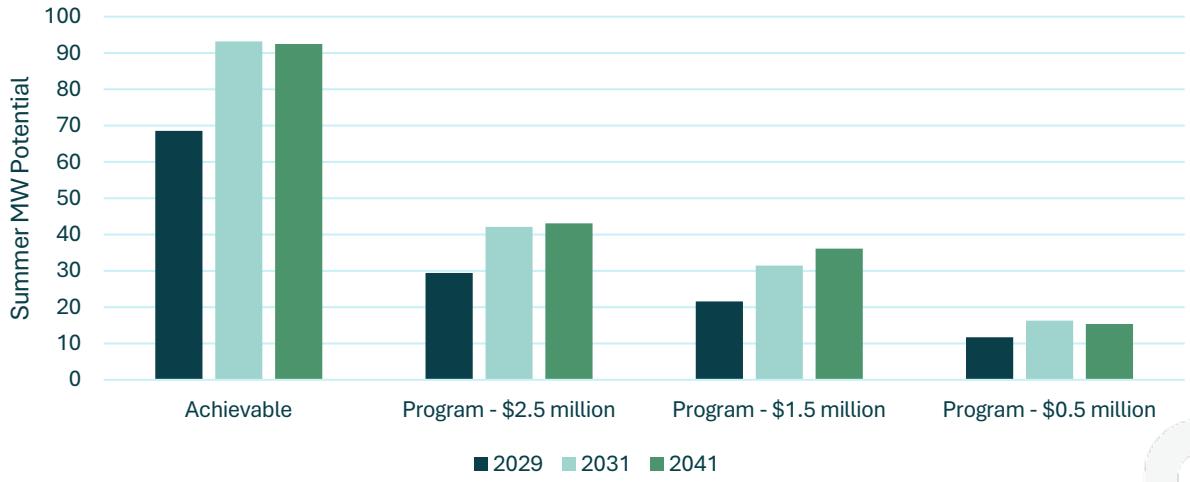


TABLE 7-3. CUMULATIVE SEASONAL SUMMARY RESULTS FOR DEMAND RESPONSE IN FINAL YEAR OF STUDY

Potential	Summer MW	Winter MW
Achievable	92.5	82.6
Program - $2.5 million	43.1	43.5
Program - $1.5 million	36.1	32.8
Program - $0.5 million	15.4	16.0

Table 7-4 provides 15-year summer achievable and program potential by program.

TABLE 7-4. SUMMER DEMAND RESPONSE CUMULATIVE POTENTIAL BY PROGRAM IN FINAL YEAR OF STUDY

Summer MW Potential	Achievable	Program - $2.5 million	Program - $1.5 million	Program - $0.5 million
Residential DLC Thermostat	12	5	2	1
Residential CVR	5	5	5	5
Residential DLC Electric Vehicle	3	1	0.3	N/A
Residential Electric Vehicle TOU	4	4	4	N/A
Residential TOU	1	2	2	N/A
Residential CPP	4	5	5	N/A
Residential DLC AC Switch	8	N/A	N/A	N/A
Residential DLC Water Heater Switch	5	N/A	N/A	N/A
Residential DLC Water Grid Enabled	2	N/A	N/A	N/A
Residential DLC Swimming Pool Pump	2	N/A	N/A	N/A
C&I DLC Thermostat	4	4	3	1

Summer MW Potential	Achievable	Program - $2.5 million	Program - $1.5 million	Program - $0.5 million
C&I DLC Water Heater Switch	3	3	3	1
C&I Capacity Bidding	10	3	1	0.4
C&I CVR	7	7	7	7
C&I TOU	1	1	1	N/A
C&I CPP	4	4	4	N/A
Residential Peak Time Rebate	4	N/A	N/A	N/A
Residential Battery Storage	0.1	N/A	N/A	N/A
Residential Generator	1	N/A	N/A	N/A
C&I DLC AC Switch	2	N/A	N/A	N/A
C&I DLC Water Heater Grid Enabled	2	N/A	N/A	N/A
C&I DLC Electric Vehicle	0.001	N/A	N/A	N/A
C&I Electric Vehicle TOU	0.002	N/A	N/A	N/A
C&I Battery Storage	0.1	N/A	N/A	N/A
C&I Interruptible Rate	10	N/A	N/A	N/A

08 DERMS DEVELOPMENT PLAN

In Fall 2025, BREC partnered with ACES to develop and administer a Request for Proposals (RFP) process to deploy a scalable Distributed Energy Resource Management System (DERMS) solution across BREC and its Member-Owners. The RFP was issued in December and distributed to 16 targeted vendors.

Between January and February 2026, BREC and ACES received seven responses from targeted vendors, along with three additional unsolicited responses submitted through ACES's RFP website. Of the ten total responses received, eight vendors elected to advance in the process and completed software demonstrations for the BREC/ACES evaluation team.

Following completion of the demonstrations, the ACES team conducted a comparative analysis of the vendor responses and, in April, developed a shortlist of three vendors for further consideration. The shortlisted vendors then proceeded through a second phase of evaluation and analysis. BREC and ACES collaborated to assess, rank, and prioritize the finalists before presenting a recommendation to the BREC Board. In May, BREC selected a preferred vendor and initiated contract negotiations.

APPENDIX A: RESIDENTIAL MEASURE DETAIL

Big Rivers — **Measure Assumption Tab**

Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW	Per unit NG Saving	Per Unit Water Savings	RC EUL	EE EUL	Initial Measure Cost
1001	Appliances	ENERGY STAR Refrigerator	SF	N/A	MO	349.2	10%	35.0	0.005	0.005	0.00	0	15.0	15.0	$28.0
1002	Appliances	ENERGY STAR Refrigerator	SF	N/A	NC	349.2	10%	35.0	0.005	0.005	0.00	0	15.0	15.0	$28.0
1003	Appliances	ENERGY STAR Refrigerator	MH	N/A	MO	349.2	10%	35.0	0.005	0.005	0.00	0	15.0	15.0	$28.0
1004	Appliances	ENERGY STAR Refrigerator	MH	N/A	NC	349.2	10%	35.0	0.005	0.005	0.00	0	15.0	15.0	$28.0
1005	Appliances	CEE Tier 2 Refrigerator	SF	N/A	MO	349.2	15%	52.4	0.008	0.008	0.00	0	15.0	15.0	$112.0
1006	Appliances	CEE Tier 2 Refrigerator	SF	N/A	NC	349.2	15%	52.4	0.008	0.008	0.00	0	15.0	15.0	$112.0
1007	Appliances	CEE Tier 2 Refrigerator	MH	N/A	MO	349.2	15%	52.4	0.008	0.008	0.00	0	15.0	15.0	$112.0
1008	Appliances	CEE Tier 2 Refrigerator	MH	N/A	NC	349.2	15%	52.4	0.008	0.008	0.00	0	15.0	15.0	$112.0
1009	Appliances	CEE Tier 3 Refrigerator	SF	N/A	MO	349.2	20%	69.8	0.011	0.011	0.00	0	15.0	15.0	$134.0
1010	Appliances	CEE Tier 3 Refrigerator	SF	N/A	NC	349.2	20%	69.8	0.011	0.011	0.00	0	15.0	15.0	$134.0
1011	Appliances	CEE Tier 3 Refrigerator	MH	N/A	MO	349.2	20%	69.8	0.011	0.011	0.00	0	15.0	15.0	$134.0
1012	Appliances	CEE Tier 3 Refrigerator	MH	N/A	NC	349.2	20%	69.8	0.011	0.011	0.00	0	15.0	15.0	$134.0
1013	Appliances	Refrigerator Recycling	SF	N/A	Recycle	900.9	100%	900.9	0.111	0.111	0.00	0	15.0	7.0	$170.0
1014	Appliances	Refrigerator Recycling	MH	N/A	Recycle	900.9	100%	900.9	0.111	0.111	0.00	0	15.0	7.0	$170.0
1015	Appliances	ENERGY STAR Clothes Washer	SF	N/A	MO	590.0	24%	139.6	0.018	0.018	0.00	1,595	14.0	14.0	$87.0
1016	Appliances	ENERGY STAR Clothes Washer	SF	N/A	NC	590.0	24%	139.6	0.018	0.018	0.00	1,595	14.0	14.0	$87.0
1017	Appliances	ENERGY STAR Clothes Washer	MH	N/A	MO	590.0	24%	139.6	0.018	0.018	0.00	1,595	14.0	14.0	$87.0
1018	Appliances	ENERGY STAR Clothes Washer	MH	N/A	NC	590.0	24%	139.6	0.018	0.018	0.00	1,595	14.0	14.0	$87.0
1019	Appliances	ENERGY STAR Clothes Washer (CEE Tier 2)	SF	N/A	MO	590.0	43%	254.8	0.033	0.033	0.00	2,500	14.0	14.0	$85.0
1020	Appliances	ENERGY STAR Clothes Washer (CEE Tier 2)	SF	N/A	NC	590.0	43%	254.8	0.033	0.033	0.00	2,500	14.0	14.0	$85.0
1021	Appliances	ENERGY STAR Clothes Washer (CEE Tier 2)	MH	N/A	MO	590.0	43%	254.8	0.033	0.033	0.00	2,500	14.0	14.0	$85.0
1022	Appliances	ENERGY STAR Clothes Washer (CEE Tier 2)	MH	N/A	NC	590.0	43%	254.8	0.033	0.033	0.00	2,500	14.0	14.0	$85.0
1023	Appliances	ENERGY STAR Clothes Washer (CEE Tier 3)	SF	N/A	MO	590.0	47%	275.6	0.036	0.036	0.00	2,709	14.0	14.0	$99.0
1024	Appliances	ENERGY STAR Clothes Washer (CEE Tier 3)	SF	N/A	NC	590.0	47%	275.6	0.036	0.036	0.00	2,709	14.0	14.0	$99.0
1025	Appliances	ENERGY STAR Clothes Washer (CEE Tier 3)	MH	N/A	MO	590.0	47%	275.6	0.036	0.036	0.00	2,709	14.0	14.0	$99.0
1026	Appliances	ENERGY STAR Clothes Washer (CEE Tier 3)	MH	N/A	NC	590.0	47%	275.6	0.036	0.036	0.00	2,709	14.0	14.0	$99.0
1027	Appliances	ENERGY STAR Dishwasher	SF	N/A	MO	307.0	13%	40.0	0.003	0.003	0.00	302	11.0	11.0	$75.7
1028	Appliances	ENERGY STAR Dishwasher	SF	N/A	NC	307.0	13%	40.0	0.003	0.003	0.00	302	11.0	11.0	$75.7
1029	Appliances	ENERGY STAR Dishwasher	MH	N/A	MO	307.0	13%	40.0	0.003	0.003	0.00	302	11.0	11.0	$75.7
1030	Appliances	ENERGY STAR Dishwasher	MH	N/A	NC	307.0	13%	40.0	0.003	0.003	0.00	302	11.0	11.0	$75.7
1031	Appliances	ENERGY STAR Dehumidifier	SF	N/A	MO	1,095.0	12%	134.0	0.030	0.030	0.00	0	12.0	12.0	$35.0
1032	Appliances	ENERGY STAR Dehumidifier	SF	N/A	NC	1,095.0	12%	134.0	0.030	0.030	0.00	0	12.0	12.0	$35.0
1033	Appliances	ENERGY STAR Dehumidifier	MH	N/A	MO	1,095.0	12%	134.0	0.030	0.030	0.00	0	12.0	12.0	$35.0
1034	Appliances	ENERGY STAR Dehumidifier	MH	N/A	NC	1,095.0	12%	134.0	0.030	0.030	0.00	0	12.0	12.0	$35.0
1035	Appliances	ENERGY STAR Most Efficient Dehumidifier	SF	N/A	MO	1,095.0	17%	188.0	0.043	0.043	0.00	0	12.0	12.0	$100.0
1036	Appliances	ENERGY STAR Most Efficient Dehumidifier	SF	N/A	NC	1,095.0	17%	188.0	0.043	0.043	0.00	0	12.0	12.0	$100.0
1037	Appliances	ENERGY STAR Most Efficient Dehumidifier	MH	N/A	MO	1,095.0	17%	188.0	0.043	0.043	0.00	0	12.0	12.0	$100.0
1038	Appliances	ENERGY STAR Most Efficient Dehumidifier	MH	N/A	NC	1,095.0	17%	188.0	0.043	0.043	0.00	0	12.0	12.0	$100.0
1039	Appliances	ENERGY STAR Freezer	SF	N/A	MO	277.3	10%	27.8	0.004	0.003	0.00	0	21.0	21.0	$5.0
1040	Appliances	ENERGY STAR Freezer	SF	N/A	NC	277.3	10%	27.8	0.004	0.003	0.00	0	21.0	21.0	$5.0
1041	Appliances	ENERGY STAR Freezer	MH	N/A	MO	277.3	10%	27.8	0.004	0.003	0.00	0	21.0	21.0	$5.0
1042	Appliances	ENERGY STAR Freezer	MH	N/A	NC	277.3	10%	27.8	0.004	0.003	0.00	0	21.0	21.0	$5.0
1043	Appliances	Freezer Recycling	SF	N/A	Recycle	905.0	100%	905.0	0.106	0.090	0.00	0	21.0	7.0	$170.0
1044	Appliances	Freezer Recycling	MH	N/A	Recycle	905.0	100%	905.0	0.106	0.090	0.00	0	21.0	7.0	$170.0
1045	Appliances	ENERGY STAR Clothes Dryer	SF	N/A	MO	768.9	21%	160.0	0.022	0.022	0.00	0	16.0	16.0	$152.0
1046	Appliances	ENERGY STAR Clothes Dryer	SF	N/A	NC	768.9	21%	160.0	0.022	0.022	0.00	0	16.0	16.0	$152.0
1047	Appliances	ENERGY STAR Clothes Dryer	MH	N/A	MO	768.9	21%	160.0	0.022	0.022	0.00	0	16.0	16.0	$152.0
1048	Appliances	ENERGY STAR Clothes Dryer	MH	N/A	NC	768.9	21%	160.0	0.022	0.022	0.00	0	16.0	16.0	$152.0
2001	Behavioral	Home Energy Management System	SF	N/A	MO	13,791.0	5%	689.6	0.079	0.079	0.00	0	5.0	5.0	$100.0
2002	Behavioral	Home Energy Management System	SF	N/A	NC	13,791.0	5%	689.6	0.079	0.079	0.00	0	5.0	5.0	$100.0
2003	Behavioral	Home Energy Management System	MH	N/A	MO	13,791.0	5%	689.6	0.079	0.079	0.00	0	5.0	5.0	$100.0
2004	Behavioral	Home Energy Management System	MH	N/A	NC	13,791.0	5%	689.6	0.079	0.079	0.00	0	5.0	5.0	$100.0

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Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW	Per unit NG Saving	Per Unit Water Savings	RC EUL	EE EUL	Initial Measure Cost
2005	Behavioral	Online Energy Audit	SF	N/A	MO	13,791.0	2%	275.8	0.031	0.031	0.00	0	1.0	1.0	$7.0
2006	Behavioral	Online Energy Audit	SF	N/A	NC	13,791.0	2%	275.8	0.031	0.031	0.00	0	1.0	1.0	$7.0
2007	Behavioral	Online Energy Audit	MH	N/A	MO	13,791.0	2%	275.8	0.031	0.031	0.00	0	1.0	1.0	$7.0
2008	Behavioral	Online Energy Audit	MH	N/A	NC	13,791.0	2%	275.8	0.031	0.031	0.00	0	1.0	1.0	$7.0
3001	HVAC Equipment	ASHP Tune Up	SF	N/A	Retrofit	5,074.0	5%	253.7	0.127	0.046	0.00	0	3.0	3.0	$225.0
3002	HVAC Equipment	ASHP Tune Up	SF	N/A	NC	5,074.0	5%	253.7	0.127	0.046	0.00	0	3.0	3.0	$225.0
3003	HVAC Equipment	ASHP Tune Up	MH	N/A	Retrofit	4,228.3	5%	211.4	0.106	0.038	0.00	0	3.0	3.0	$225.0
3004	HVAC Equipment	ASHP Tune Up	MH	N/A	NC	4,228.3	5%	211.4	0.106	0.038	0.00	0	3.0	3.0	$225.0
3005	HVAC Equipment	Air Source Heat Pump 15.2 SEER2 - Heat pump baseline	SF	N/A	MO	5,074.0	10%	506.9	0.125	0.091	0.00	0	16.0	16.0	$636.0
3006	HVAC Equipment	Air Source Heat Pump 15.2 SEER2 - Heat pump baseline	SF	N/A	NC	5,074.0	10%	506.9	0.125	0.091	0.00	0	16.0	16.0	$636.0
3007	HVAC Equipment	Air Source Heat Pump 15.2 SEER2 - Heat pump baseline	MH	N/A	MO	4,228.3	10%	422.4	0.104	0.076	0.00	0	16.0	16.0	$530.0
3008	HVAC Equipment	Air Source Heat Pump 15.2 SEER2 - Heat pump baseline	MH	N/A	NC	4,228.3	10%	422.4	0.104	0.076	0.00	0	16.0	16.0	$530.0
3009	HVAC Equipment	Air Source Heat Pump 16.2 SEER2 - Heat pump baseline	SF	N/A	MO	5,074.0	18%	890.3	0.247	0.160	0.00	0	16.0	16.0	$1,273.0
3010	HVAC Equipment	Air Source Heat Pump 16.2 SEER2 - Heat pump baseline	SF	N/A	NC	5,074.0	18%	890.3	0.247	0.160	0.00	0	16.0	16.0	$1,273.0
3011	HVAC Equipment	Air Source Heat Pump 16.2 SEER2 - Heat pump baseline	MH	N/A	MO	4,228.3	18%	741.9	0.206	0.133	0.00	0	16.0	16.0	$1,061.0
3012	HVAC Equipment	Air Source Heat Pump 16.2 SEER2 - Heat pump baseline	MH	N/A	NC	4,228.3	18%	741.9	0.206	0.133	0.00	0	16.0	16.0	$1,061.0
3013	HVAC Equipment	Air Source Heat Pump 17.1 SEER2 - Heat pump baseline	SF	N/A	MO	5,074.0	26%	1,328.9	0.345	0.239	0.00	0	16.0	16.0	$1,909.0
3014	HVAC Equipment	Air Source Heat Pump 17.1 SEER2 - Heat pump baseline	SF	N/A	NC	5,074.0	26%	1,328.9	0.345	0.239	0.00	0	16.0	16.0	$1,909.0
3015	HVAC Equipment	Air Source Heat Pump 17.1 SEER2 - Heat pump baseline	MH	N/A	MO	4,228.3	26%	1,107.4	0.287	0.199	0.00	0	16.0	16.0	$1,591.0
3016	HVAC Equipment	Air Source Heat Pump 17.1 SEER2 - Heat pump baseline	MH	N/A	NC	4,228.3	26%	1,107.4	0.287	0.199	0.00	0	16.0	16.0	$1,591.0
3017	HVAC Equipment	Air Source Heat Pump 18.1 SEER2 - Heat pump baseline	SF	N/A	MO	5,074.0	31%	1,583.2	0.442	2.381	0.00	0	16.0	16.0	$2,546.0
3018	HVAC Equipment	Air Source Heat Pump 18.1 SEER2 - Heat pump baseline	SF	N/A	NC	5,074.0	31%	1,583.2	0.442	2.381	0.00	0	16.0	16.0	$2,546.0
3019	HVAC Equipment	Air Source Heat Pump 18.1 SEER2 - Heat pump baseline	MH	N/A	MO	4,228.3	31%	1,319.3	0.368	1.984	0.00	0	16.0	16.0	$2,122.0
3020	HVAC Equipment	Air Source Heat Pump 18.1 SEER2 - Heat pump baseline	MH	N/A	NC	4,228.3	31%	1,319.3	0.368	1.984	0.00	0	16.0	16.0	$2,122.0
3021	HVAC Equipment	Air Source Heat Pump 19 SEER2 - Heat pump baseline	SF	N/A	MO	5,074.0	35%	1,798.4	0.521	2.705	0.00	0	16.0	16.0	$3,182.0
3022	HVAC Equipment	Air Source Heat Pump 19 SEER2 - Heat pump baseline	SF	N/A	NC	5,074.0	35%	1,798.4	0.521	2.705	0.00	0	16.0	16.0	$3,182.0
3023	HVAC Equipment	Air Source Heat Pump 19 SEER2 - Heat pump baseline	MH	N/A	MO	4,228.3	35%	1,498.7	0.434	2.254	0.00	0	16.0	16.0	$2,652.0
3024	HVAC Equipment	Air Source Heat Pump 19 SEER2 - Heat pump baseline	MH	N/A	NC	4,228.3	35%	1,498.7	0.434	2.254	0.00	0	16.0	16.0	$2,652.0
3025	HVAC Equipment	Air Source Heat Pump 20 SEER2 - Heat pump baseline	*SF*	N/A	MO	5,074.0	39%	1,991.4	0.600	2.995	0.00	0	16.0	16.0	$3,819.0
3026	HVAC Equipment	Air Source Heat Pump 20 SEER2 - Heat pump baseline	*SF*	N/A	NC	5,074.0	39%	1,991.4	0.600	2.995	0.00	0	16.0	16.0	$3,819.0
3027	HVAC Equipment	Air Source Heat Pump 20 SEER2 - Heat pump baseline	MH	N/A	MO	4,228.3	39%	1,659.5	0.500	2.496	0.00	0	16.0	16.0	$3,182.0
3028	HVAC Equipment	Air Source Heat Pump 20 SEER2 - Heat pump baseline	MH	N/A	NC	4,228.3	39%	1,659.5	0.500	2.496	0.00	0	16.0	16.0	$3,182.0
3029	HVAC Equipment	Ground Source Heat Pump 20 SEER - Heat pump baseline	SF	N/A	MO	5,074.0	39%	1,991.4	0.359	0.358	0.00	0	25.0	25.0	$3,509.0
3030	HVAC Equipment	Ground Source Heat Pump 20 SEER - Heat pump baseline	SF	N/A	NC	5,074.0	39%	1,991.4	0.359	0.358	0.00	0	25.0	25.0	$3,509.0
3031	HVAC Equipment	Ground Source Heat Pump 20 SEER - Heat pump baseline	MH	N/A	MO	4,228.3	39%	1,659.5	0.299	0.298	0.00	0	25.0	25.0	$1,830.5
3032	HVAC Equipment	Ground Source Heat Pump 20 SEER - Heat pump baseline	MH	N/A	NC	4,228.3	39%	1,659.5	0.299	0.298	0.00	0	25.0	25.0	$1,830.5
3033	HVAC Equipment	Ground Source Heat Pump 21.5 SEER - Heat pump baseline	SF	N/A	MO	5,074.0	40%	2,053.7	0.370	0.369	0.00	0	25.0	25.0	$3,509.0
3034	HVAC Equipment	Ground Source Heat Pump 21.5 SEER - Heat pump baseline	SF	N/A	NC	5,074.0	40%	2,053.7	0.370	0.369	0.00	0	25.0	25.0	$3,509.0
3035	HVAC Equipment	Ground Source Heat Pump 21.5 SEER - Heat pump baseline	MH	N/A	MO	4,228.3	40%	1,711.4	0.308	0.307	0.00	0	25.0	25.0	$1,830.5
3036	HVAC Equipment	Ground Source Heat Pump 21.5 SEER - Heat pump baseline	MH	N/A	NC	4,228.3	40%	1,711.4	0.308	0.307	0.00	0	25.0	25.0	$1,830.5
3037	HVAC Equipment	Ground Source Heat Pump 23.5 SEER - Heat pump baseline	SF	N/A	MO	5,074.0	42%	2,124.4	0.383	0.382	0.00	0	25.0	25.0	$3,509.0
3038	HVAC Equipment	Ground Source Heat Pump 23.5 SEER - Heat pump baseline	SF	N/A	NC	5,074.0	42%	2,124.4	0.383	0.382	0.00	0	25.0	25.0	$3,509.0
3039	HVAC Equipment	Ground Source Heat Pump 23.5 SEER - Heat pump baseline	MH	N/A	MO	4,228.3	42%	1,770.3	0.319	0.318	0.00	0	25.0	25.0	$1,830.5
3040	HVAC Equipment	Ground Source Heat Pump 23.5 SEER - Heat pump baseline	MH	N/A	NC	4,228.3	42%	1,770.3	0.319	0.318	0.00	0	25.0	25.0	$1,830.5
3041	HVAC Equipment	Ground Source Heat Pump 29 SEER - Heat pump baseline	SF	N/A	MO	5,074.0	45%	2,268.4	0.409	0.407	0.00	0	25.0	25.0	$3,509.0
3042	HVAC Equipment	Ground Source Heat Pump 29 SEER - Heat pump baseline	SF	N/A	NC	5,074.0	45%	2,268.4	0.409	0.407	0.00	0	25.0	25.0	$3,509.0
3043	HVAC Equipment	Ground Source Heat Pump 29 SEER - Heat pump baseline	*MH*	N/A	MO	4,228.3	45%	1,890.4	0.340	0.340	0.00	0	25.0	25.0	$1,830.5
3044	HVAC Equipment	Ground Source Heat Pump 29 SEER - Heat pump baseline	*MH*	N/A	NC	4,228.3	45%	1,890.4	0.340	0.340	0.00	0	25.0	25.0	$1,830.5
3045	HVAC Equipment	Ductless Heat Pump 8.5 HSPF2 - Heat pump baseline	SF	N/A	MO	5,074.0	11%	536.2	0.131	0.096	0.00	0	16.0	16.0	$186.0
3046	HVAC Equipment	Ductless Heat Pump 8.5 HSPF2 - Heat pump baseline	SF	N/A	NC	5,074.0	11%	536.2	0.131	0.096	0.00	0	16.0	16.0	$186.0
3047	HVAC Equipment	Ductless Heat Pump 8.5 HSPF2 - Heat pump baseline	MH	N/A	MO	4,228.3	11%	446.9	0.109	0.080	0.00	0	16.0	16.0	$155.0
3048	HVAC Equipment	Ductless Heat Pump 8.5 HSPF2 - Heat pump baseline	MH	N/A	NC	4,228.3	11%	446.9	0.109	0.080	0.00	0	16.0	16.0	$155.0

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Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW	Per unit NG Saving	Per Unit Water Savings	RC EUL	EE EUL	Initial Measure Cost
3049	HVAC Equipment	Ductless Heat Pump 9.4 HSPF2 - Heat pump baseline	SF	N/A	MO	5,074.0	19%	941.7	0.260	0.169	0.00	0	16.0	16.0	$672.0
3050	HVAC Equipment	Ductless Heat Pump 9.4 HSPF2 - Heat pump baseline	SF	N/A	NC	5,074.0	19%	941.7	0.260	0.169	0.00	0	16.0	16.0	$672.0
3051	HVAC Equipment	Ductless Heat Pump 9.4 HSPF2 - Heat pump baseline	MH	N/A	MO	4,228.3	19%	784.8	0.217	0.141	0.00	0	16.0	16.0	$560.0
3052	HVAC Equipment	Ductless Heat Pump 9.4 HSPF2 - Heat pump baseline	MH	N/A	NC	4,228.3	19%	784.8	0.217	0.141	0.00	0	16.0	16.0	$560.0
3053	HVAC Equipment	Ductless Heat Pump 10.8 HSPF2 - Heat pump baseline	SF	N/A	MO	5,074.0	28%	1,405.8	0.363	0.252	0.00	0	16.0	16.0	$1,002.0
3054	HVAC Equipment	Ductless Heat Pump 10.8 HSPF2 - Heat pump baseline	SF	N/A	NC	5,074.0	28%	1,405.8	0.363	0.252	0.00	0	16.0	16.0	$1,002.0
3055	HVAC Equipment	Ductless Heat Pump 10.8 HSPF2 - Heat pump baseline	MH	N/A	MO	4,228.3	28%	1,171.5	0.302	0.210	0.00	0	16.0	16.0	$835.0
3056	HVAC Equipment	Ductless Heat Pump 10.8 HSPF2 - Heat pump baseline	MH	N/A	NC	4,228.3	28%	1,171.5	0.302	0.210	0.00	0	16.0	16.0	$835.0
3057	HVAC Equipment	Ductless Heat Pump 11.7 HSPF2 - Heat pump baseline	SF	N/A	MO	5,074.0	33%	1,674.7	0.455	0.301	0.00	0	16.0	16.0	$1,980.0
3058	HVAC Equipment	Ductless Heat Pump 11.7 HSPF2 - Heat pump baseline	SF	N/A	NC	5,074.0	33%	1,674.7	0.455	0.301	0.00	0	16.0	16.0	$1,980.0
3059	HVAC Equipment	Ductless Heat Pump 11.7 HSPF2 - Heat pump baseline	MH	N/A	MO	4,228.3	33%	1,395.6	0.379	0.251	0.00	0	16.0	16.0	$1,650.0
3060	HVAC Equipment	Ductless Heat Pump 11.7 HSPF2 - Heat pump baseline	MH	N/A	NC	4,228.3	33%	1,395.6	0.379	0.251	0.00	0	16.0	16.0	$1,650.0
3061	HVAC Equipment	Ductless Heat Pump 8.5 HSPF2 - Heat pump baseline (1-ton offset)	SF	N/A	MO	5,074.0	4%	178.7	0.044	0.032	0.00	0	16.0	16.0	$62.0
3062	HVAC Equipment	Ductless Heat Pump 8.5 HSPF2 - Heat pump baseline (1-ton offset)	SF	N/A	NC	5,074.0	4%	178.7	0.044	0.032	0.00	0	16.0	16.0	$62.0
3063	HVAC Equipment	Ductless Heat Pump 8.5 HSPF2 - Heat pump baseline (1-ton offset)	MH	N/A	MO	4,228.3	4%	178.7	0.044	0.032	0.00	0	16.0	16.0	$62.0
3064	HVAC Equipment	Ductless Heat Pump 8.5 HSPF2 - Heat pump baseline (1-ton offset)	MH	N/A	NC	4,228.3	4%	178.7	0.044	0.032	0.00	0	16.0	16.0	$62.0
3065	HVAC Equipment	Ductless Heat Pump 9.4 HSPF2 - Heat pump baseline (1-ton offset)	SF	N/A	MO	5,074.0	6%	313.9	0.087	0.056	0.00	0	16.0	16.0	$224.0
3066	HVAC Equipment	Ductless Heat Pump 9.4 HSPF2 - Heat pump baseline (1-ton offset)	SF	N/A	NC	5,074.0	6%	313.9	0.087	0.056	0.00	0	16.0	16.0	$224.0
3067	HVAC Equipment	Ductless Heat Pump 9.4 HSPF2 - Heat pump baseline (1-ton offset)	MH	N/A	MO	4,228.3	7%	313.9	0.087	0.056	0.00	0	16.0	16.0	$224.0
3068	HVAC Equipment	Ductless Heat Pump 9.4 HSPF2 - Heat pump baseline (1-ton offset)	MH	N/A	NC	4,228.3	7%	313.9	0.087	0.056	0.00	0	16.0	16.0	$224.0
3069	HVAC Equipment	Ductless Heat Pump 10.8 HSPF2 - Heat pump baseline (1-ton offset)	SF	N/A	MO	5,074.0	9%	468.6	0.121	0.084	0.00	0	16.0	16.0	$334.0
3070	HVAC Equipment	Ductless Heat Pump 10.8 HSPF2 - Heat pump baseline (1-ton offset)	SF	N/A	NC	5,074.0	9%	468.6	0.121	0.084	0.00	0	16.0	16.0	$334.0
3071	HVAC Equipment	Ductless Heat Pump 10.8 HSPF2 - Heat pump baseline (1-ton offset)	MH	N/A	MO	4,228.3	11%	468.6	0.121	0.084	0.00	0	16.0	16.0	$334.0
3072	HVAC Equipment	Ductless Heat Pump 10.8 HSPF2 - Heat pump baseline (1-ton offset)	MH	N/A	NC	4,228.3	11%	468.6	0.121	0.084	0.00	0	16.0	16.0	$334.0
3073	HVAC Equipment	Ductless Heat Pump 11.7 HSPF2 - Heat pump baseline (1-ton offset)	SF	N/A	MO	5,074.0	11%	558.2	0.152	0.100	0.00	0	16.0	16.0	$660.0
3074	HVAC Equipment	Ductless Heat Pump 11.7 HSPF2 - Heat pump baseline (1-ton offset)	SF	N/A	NC	5,074.0	11%	558.2	0.152	0.100	0.00	0	16.0	16.0	$660.0
3075	HVAC Equipment	Ductless Heat Pump 11.7 HSPF2 - Heat pump baseline (1-ton offset)	MH	N/A	MO	4,228.3	13%	558.2	0.152	0.100	0.00	0	16.0	16.0	$660.0
3076	HVAC Equipment	Ductless Heat Pump 11.7 HSPF2 - Heat pump baseline (1-ton offset)	MH	N/A	NC	4,228.3	13%	558.2	0.152	0.100	0.00	0	16.0	16.0	$660.0
3077	HVAC Equipment	Air Source Heat Pump 15.2 SEER2 - Electric furnace baseline	SF	N/A	MO	10,838.5	59%	6,341.1	0.125	1.139	0.00	0	16.0	16.0	$636.0
3078	HVAC Equipment	Air Source Heat Pump 15.2 SEER2 - Electric furnace baseline	SF	N/A	NC	10,838.5	59%	6,341.1	0.125	1.139	0.00	0	16.0	16.0	$636.0
3079	HVAC Equipment	Air Source Heat Pump 15.2 SEER2 - Electric furnace baseline	MH	N/A	MO	9,032.1	59%	5,284.2	0.104	0.949	0.00	0	16.0	16.0	$530.0
3080	HVAC Equipment	Air Source Heat Pump 15.2 SEER2 - Electric furnace baseline	MH	N/A	NC	9,032.1	59%	5,284.2	0.104	0.949	0.00	0	16.0	16.0	$530.0
3081	HVAC Equipment	Air Source Heat Pump 16.2 SEER2 - Electric furnace baseline	SF	N/A	MO	10,838.5	62%	6,724.5	0.247	1.208	0.00	0	16.0	16.0	$1,273.0
3082	HVAC Equipment	Air Source Heat Pump 16.2 SEER2 - Electric furnace baseline	SF	N/A	NC	10,838.5	62%	6,724.5	0.247	1.208	0.00	0	16.0	16.0	$1,273.0
3083	HVAC Equipment	Air Source Heat Pump 16.2 SEER2 - Electric furnace baseline	MH	N/A	MO	9,032.1	62%	5,603.7	0.206	1.006	0.00	0	16.0	16.0	$1,061.0
3084	HVAC Equipment	Air Source Heat Pump 16.2 SEER2 - Electric furnace baseline	MH	N/A	NC	9,032.1	62%	5,603.7	0.206	1.006	0.00	0	16.0	16.0	$1,061.0
3085	HVAC Equipment	Air Source Heat Pump 17.1 SEER2 - Electric furnace baseline	SF	N/A	MO	10,838.5	66%	7,163.1	0.345	1.286	0.00	0	16.0	16.0	$1,909.0
3086	HVAC Equipment	Air Source Heat Pump 17.1 SEER2 - Electric furnace baseline	SF	N/A	NC	10,838.5	66%	7,163.1	0.345	1.286	0.00	0	16.0	16.0	$1,909.0
3087	HVAC Equipment	Air Source Heat Pump 17.1 SEER2 - Electric furnace baseline	MH	N/A	MO	9,032.1	66%	5,969.3	0.287	1.072	0.00	0	16.0	16.0	$1,591.0
3088	HVAC Equipment	Air Source Heat Pump 17.1 SEER2 - Electric furnace baseline	MH	N/A	NC	9,032.1	66%	5,969.3	0.287	1.072	0.00	0	16.0	16.0	$1,591.0
3089	HVAC Equipment	Air Source Heat Pump 18.1 SEER2 - Electric furnace baseline	SF	N/A	MO	10,838.5	68%	7,417.4	0.442	4.655	0.00	0	16.0	16.0	$2,546.0
3090	HVAC Equipment	Air Source Heat Pump 18.1 SEER2 - Electric furnace baseline	SF	N/A	NC	10,838.5	68%	7,417.4	0.442	4.655	0.00	0	16.0	16.0	$2,546.0
3091	HVAC Equipment	Air Source Heat Pump 18.1 SEER2 - Electric furnace baseline	MH	N/A	MO	9,032.1	68%	6,181.2	0.368	3.879	0.00	0	16.0	16.0	$2,122.0
3092	HVAC Equipment	Air Source Heat Pump 18.1 SEER2 - Electric furnace baseline	MH	N/A	NC	9,032.1	68%	6,181.2	0.368	3.879	0.00	0	16.0	16.0	$2,122.0
3093	HVAC Equipment	Air Source Heat Pump 19 SEER2 - Electric furnace baseline	SF	N/A	MO	10,838.5	70%	7,632.6	0.521	4.790	0.00	0	16.0	16.0	$3,182.0
3094	HVAC Equipment	Air Source Heat Pump 19 SEER2 - Electric furnace baseline	SF	N/A	NC	10,838.5	70%	7,632.6	0.521	4.790	0.00	0	16.0	16.0	$3,182.0
3095	HVAC Equipment	Air Source Heat Pump 19 SEER2 - Electric furnace baseline	MH	N/A	MO	9,032.1	70%	6,360.5	0.434	3.992	0.00	0	16.0	16.0	$2,652.0
3096	HVAC Equipment	Air Source Heat Pump 19 SEER2 - Electric furnace baseline	MH	N/A	NC	9,032.1	70%	6,360.5	0.434	3.992	0.00	0	16.0	16.0	$2,652.0
3097	HVAC Equipment	Air Source Heat Pump 20 SEER2 - Electric furnace baseline	SF	N/A	MO	10,838.5	72%	7,825.6	0.600	4.911	0.00	0	16.0	16.0	$3,819.0
3098	HVAC Equipment	Air Source Heat Pump 20 SEER2 - Electric furnace baseline	SF	N/A	NC	10,838.5	72%	7,825.6	0.600	4.911	0.00	0	16.0	16.0	$3,819.0
3099	HVAC Equipment	Air Source Heat Pump 20 SEER2 - Electric furnace baseline	MH	N/A	MO	9,032.1	72%	6,521.4	0.500	4.093	0.00	0	16.0	16.0	$3,182.0
3100	HVAC Equipment	Air Source Heat Pump 20 SEER2 - Electric furnace baseline	MH	N/A	NC	9,032.1	72%	6,521.4	0.500	4.093	0.00	0	16.0	16.0	$3,182.0

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Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW	Per unit NG Saving	Per Unit Water Savings	RC EUL	EE EUL	Initial Measure Cost
3101	HVAC Equipment	Ductless Heat Pump 8.5 HSPF2 - Electric resistance baseline	SF	N/A	MO	10,838.5	62%	6,713.6	0.131	1.206	0.00	0	16.0	16.0	$186.0
3102	HVAC Equipment	Ductless Heat Pump 8.5 HSPF2 - Electric resistance baseline	SF	N/A	NC	10,838.5	62%	6,713.6	0.131	1.206	0.00	0	16.0	16.0	$186.0
3103	HVAC Equipment	Ductless Heat Pump 8.5 HSPF2 - Electric resistance baseline	MH	N/A	MO	9,032.1	62%	5,594.7	0.109	1.005	0.00	0	16.0	16.0	$155.0
3104	HVAC Equipment	Ductless Heat Pump 8.5 HSPF2 - Electric resistance baseline	MH	N/A	NC	9,032.1	62%	5,594.7	0.109	1.005	0.00	0	16.0	16.0	$155.0
3105	HVAC Equipment	Ductless Heat Pump 9.4 HSPF2 - Electric resistance baseline	SF	N/A	MO	10,838.5	66%	7,119.1	0.260	1.279	0.00	0	16.0	16.0	$672.0
3106	HVAC Equipment	Ductless Heat Pump 9.4 HSPF2 - Electric resistance baseline	SF	N/A	NC	10,838.5	66%	7,119.1	0.260	1.279	0.00	0	16.0	16.0	$672.0
3107	HVAC Equipment	Ductless Heat Pump 9.4 HSPF2 - Electric resistance baseline	MH	N/A	MO	9,032.1	66%	5,932.6	0.217	1.065	0.00	0	16.0	16.0	$560.0
3108	HVAC Equipment	Ductless Heat Pump 9.4 HSPF2 - Electric resistance baseline	MH	N/A	NC	9,032.1	66%	5,932.6	0.217	1.065	0.00	0	16.0	16.0	$560.0
3109	HVAC Equipment	Ductless Heat Pump 10.8 HSPF2 - Electric resistance baseline	SF	N/A	MO	10,838.5	70%	7,583.2	0.363	1.362	0.00	0	16.0	16.0	$1,002.0
3110	HVAC Equipment	Ductless Heat Pump 10.8 HSPF2 - Electric resistance baseline	SF	N/A	NC	10,838.5	70%	7,583.2	0.363	1.362	0.00	0	16.0	16.0	$1,002.0
3111	HVAC Equipment	Ductless Heat Pump 10.8 HSPF2 - Electric resistance baseline	MH	N/A	MO	9,032.1	70%	6,319.4	0.302	1.135	0.00	0	16.0	16.0	$835.0
3112	HVAC Equipment	Ductless Heat Pump 10.8 HSPF2 - Electric resistance baseline	MH	N/A	NC	9,032.1	70%	6,319.4	0.302	1.135	0.00	0	16.0	16.0	$835.0
3113	HVAC Equipment	Ductless Heat Pump 11.7 HSPF2 - Electric resistance baseline	SF	N/A	MO	10,838.5	72%	7,852.1	0.455	1.410	0.00	0	16.0	16.0	$1,980.0
3114	HVAC Equipment	Ductless Heat Pump 11.7 HSPF2 - Electric resistance baseline	SF	N/A	NC	10,838.5	72%	7,852.1	0.455	1.410	0.00	0	16.0	16.0	$1,980.0
3115	HVAC Equipment	Ductless Heat Pump 11.7 HSPF2 - Electric resistance baseline	MH	N/A	MO	9,032.1	72%	6,543.4	0.379	1.175	0.00	0	16.0	16.0	$1,650.0
3116	HVAC Equipment	Ductless Heat Pump 11.7 HSPF2 - Electric resistance baseline	MH	N/A	NC	9,032.1	72%	6,543.4	0.379	1.175	0.00	0	16.0	16.0	$1,650.0
3117	HVAC Equipment	Ductless Heat Pump 8.5 HSPF2 - Electric resistance baseline (1-ton offset)	SF	N/A	MO	10,838.5	21%	2,237.9	0.044	0.402	0.00	0	16.0	16.0	$62.0
3118	HVAC Equipment	Ductless Heat Pump 8.5 HSPF2 - Electric resistance baseline (1-ton offset)	SF	N/A	NC	10,838.5	21%	2,237.9	0.044	0.402	0.00	0	16.0	16.0	$62.0
3119	HVAC Equipment	Ductless Heat Pump 8.5 HSPF2 - Electric resistance baseline (1-ton offset)	MH	N/A	MO	9,032.1	25%	2,237.9	0.044	0.402	0.00	0	16.0	16.0	$62.0
3120	HVAC Equipment	Ductless Heat Pump 8.5 HSPF2 - Electric resistance baseline (1-ton offset)	MH	N/A	NC	9,032.1	25%	2,237.9	0.044	0.402	0.00	0	16.0	16.0	$62.0
3121	HVAC Equipment	Ductless Heat Pump 9.4 HSPF2 - Electric resistance baseline (1-ton offset)	SF	N/A	MO	10,838.5	22%	2,373.0	0.087	0.426	0.00	0	16.0	16.0	$224.0
3122	HVAC Equipment	Ductless Heat Pump 9.4 HSPF2 - Electric resistance baseline (1-ton offset)	SF	N/A	NC	10,838.5	22%	2,373.0	0.087	0.426	0.00	0	16.0	16.0	$224.0
3123	HVAC Equipment	Ductless Heat Pump 9.4 HSPF2 - Electric resistance baseline (1-ton offset)	MH	N/A	MO	9,032.1	26%	2,373.0	0.087	0.426	0.00	0	16.0	16.0	$224.0
3124	HVAC Equipment	Ductless Heat Pump 9.4 HSPF2 - Electric resistance baseline (1-ton offset)	MH	N/A	NC	9,032.1	26%	2,373.0	0.087	0.426	0.00	0	16.0	16.0	$224.0
3125	HVAC Equipment	Ductless Heat Pump 10.8 HSPF2 - Electric resistance baseline (1-ton offset	SF	N/A	MO	10,838.5	23%	2,527.7	0.121	0.454	0.00	0	16.0	16.0	$334.0
3126	HVAC Equipment	Ductless Heat Pump 10.8 HSPF2 - Electric resistance baseline (1-ton offset	SF	N/A	NC	10,838.5	23%	2,527.7	0.121	0.454	0.00	0	16.0	16.0	$334.0
3127	HVAC Equipment	Ductless Heat Pump 10.8 HSPF2 - Electric resistance baseline (1-ton offset	MH	N/A	MO	9,032.1	28%	2,527.7	0.121	0.454	0.00	0	16.0	16.0	$334.0
3128	HVAC Equipment	Ductless Heat Pump 10.8 HSPF2 - Electric resistance baseline (1-ton offset	MH	N/A	NC	9,032.1	28%	2,527.7	0.121	0.454	0.00	0	16.0	16.0	$334.0
3129	HVAC Equipment	Ductless Heat Pump 11.7 HSPF2 - Electric resistance baseline (1-ton offset	SF	N/A	MO	10,838.5	24%	2,617.4	0.152	0.470	0.00	0	16.0	16.0	$660.0
3130	HVAC Equipment	Ductless Heat Pump 11.7 HSPF2 - Electric resistance baseline (1-ton offset	SF	N/A	NC	10,838.5	24%	2,617.4	0.152	0.470	0.00	0	16.0	16.0	$660.0
3131	HVAC Equipment	Ductless Heat Pump 11.7 HSPF2 - Electric resistance baseline (1-ton offset	MH	N/A	MO	9,032.1	29%	2,617.4	0.152	0.470	0.00	0	16.0	16.0	$660.0
3132	HVAC Equipment	Ductless Heat Pump 11.7 HSPF2 - Electric resistance baseline (1-ton offset	MH	N/A	NC	9,032.1	29%	2,617.4	0.152	0.470	0.00	0	16.0	16.0	$660.0
3133	HVAC Equipment	AC Tune Up	SF	N/A	Retrofit	1,324.3	5%	66.2	0.086	0.000	0.00	0	3.0	3.0	$225.0
3134	HVAC Equipment	AC Tune Up	SF	N/A	NC	1,324.3	5%	66.2	0.086	0.000	0.00	0	3.0	3.0	$225.0
3135	HVAC Equipment	AC Tune Up	MH	N/A	Retrofit	1,103.6	5%	55.2	0.072	0.000	0.00	0	3.0	3.0	$225.0
3136	HVAC Equipment	AC Tune Up	MH	N/A	NC	1,103.6	5%	55.2	0.072	0.000	0.00	0	3.0	3.0	$225.0
3137	HVAC Equipment	Central Air Conditioner 15.2 SEER2	SF	N/A	MO	1,324.3	6%	73.9	0.125	0.000	0.00	0	18.0	18.0	$636.0
3138	HVAC Equipment	Central Air Conditioner 15.2 SEER2	SF	N/A	NC	1,324.3	6%	73.9	0.125	0.000	0.00	0	18.0	18.0	$636.0
3139	HVAC Equipment	Central Air Conditioner 15.2 SEER2	MH	N/A	MO	1,103.6	6%	61.6	0.104	0.000	0.00	0	18.0	18.0	$530.0
3140	HVAC Equipment	Central Air Conditioner 15.2 SEER2	MH	N/A	NC	1,103.6	6%	61.6	0.104	0.000	0.00	0	18.0	18.0	$530.0
3141	HVAC Equipment	Central Air Conditioner 16.2 SEER2	SF	N/A	MO	1,324.3	11%	146.4	0.247	0.000	0.00	0	18.0	18.0	$1,273.0
3142	HVAC Equipment	Central Air Conditioner 16.2 SEER2	SF	N/A	NC	1,324.3	11%	146.4	0.247	0.000	0.00	0	18.0	18.0	$1,273.0
3143	HVAC Equipment	Central Air Conditioner 16.2 SEER2	MH	N/A	MO	1,103.6	11%	122.0	0.206	0.000	0.00	0	18.0	18.0	$1,061.0
3144	HVAC Equipment	Central Air Conditioner 16.2 SEER2	MH	N/A	NC	1,103.6	11%	122.0	0.206	0.000	0.00	0	18.0	18.0	$1,061.0
3145	HVAC Equipment	Central Air Conditioner 17.1 SEER2	SF	N/A	MO	1,324.3	15%	204.4	0.345	0.000	0.00	0	18.0	18.0	$1,909.0
3146	HVAC Equipment	Central Air Conditioner 17.1 SEER2	SF	N/A	NC	1,324.3	15%	204.4	0.345	0.000	0.00	0	18.0	18.0	$1,909.0
3147	HVAC Equipment	Central Air Conditioner 17.1 SEER2	MH	N/A	MO	1,103.6	15%	170.3	0.287	0.000	0.00	0	18.0	18.0	$1,591.0
3148	HVAC Equipment	Central Air Conditioner 17.1 SEER2	MH	N/A	NC	1,103.6	15%	170.3	0.287	0.000	0.00	0	18.0	18.0	$1,591.0
3149	HVAC Equipment	Central Air Conditioner 18.1 SEER2	SF	N/A	MO	1,324.3	20%	262.1	0.442	0.000	0.00	0	18.0	18.0	$2,546.0
3150	HVAC Equipment	Central Air Conditioner 18.1 SEER2	SF	N/A	NC	1,324.3	20%	262.1	0.442	0.000	0.00	0	18.0	18.0	$2,546.0
3151	HVAC Equipment	Central Air Conditioner 18.1 SEER2	MH	N/A	MO	1,103.6	20%	218.4	0.368	0.000	0.00	0	18.0	18.0	$2,122.0
3152	HVAC Equipment	Central Air Conditioner 18.1 SEER2	MH	N/A	NC	1,103.6	20%	218.4	0.368	0.000	0.00	0	18.0	18.0	$2,122.0

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Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW	Per unit NG Saving	Per Unit Water Savings	RC EUL	EE EUL	Initial Measure Cost
3153	HVAC Equipment	Central Air Conditioner 19 SEER2	SF	N/A	MO	1,324.3	23%	308.8	0.521	0.000	0.00	0	18.0	18.0	$3,182.0
3154	HVAC Equipment	Central Air Conditioner 19 SEER2	SF	N/A	NC	1,324.3	23%	308.8	0.521	0.000	0.00	0	18.0	18.0	$3,182.0
3155	HVAC Equipment	Central Air Conditioner 19 SEER2	MH	N/A	MO	1,103.6	23%	257.3	0.434	0.000	0.00	0	18.0	18.0	$2,652.0
3156	HVAC Equipment	Central Air Conditioner 19 SEER2	MH	N/A	NC	1,103.6	23%	257.3	0.434	0.000	0.00	0	18.0	18.0	$2,652.0
3157	HVAC Equipment	Central Air Conditioner 20 SEER2	SF	N/A	MO	1,324.3	27%	355.8	0.600	0.000	0.00	0	18.0	18.0	$3,819.0
3158	HVAC Equipment	Central Air Conditioner 20 SEER2	SF	N/A	NC	1,324.3	27%	355.8	0.600	0.000	0.00	0	18.0	18.0	$3,819.0
3159	HVAC Equipment	Central Air Conditioner 20 SEER2	MH	N/A	MO	1,103.6	27%	296.5	0.500	0.000	0.00	0	18.0	18.0	$3,182.0
3160	HVAC Equipment	Central Air Conditioner 20 SEER2	MH	N/A	NC	1,103.6	27%	296.5	0.500	0.000	0.00	0	18.0	18.0	$3,182.0
3161	HVAC Equipment	Central Air Conditioner 21 SEER2	SF	N/A	MO	1,324.3	30%	398.3	0.671	0.000	0.00	0	18.0	18.0	$4,455.0
3162	HVAC Equipment	Central Air Conditioner 21 SEER2	SF	N/A	NC	1,324.3	30%	398.3	0.671	0.000	0.00	0	18.0	18.0	$4,455.0
3163	HVAC Equipment	Central Air Conditioner 21 SEER2	MH	N/A	MO	1,103.6	30%	331.9	0.560	0.000	0.00	0	18.0	18.0	$4,455.0
3164	HVAC Equipment	Central Air Conditioner 21 SEER2	MH	N/A	NC	1,103.6	30%	331.9	0.560	0.000	0.00	0	18.0	18.0	$4,455.0
3165	HVAC Equipment	Ductless AC	SF	N/A	MO	1,324.3	15%	198.3	0.334	0.000	0.00	0	16.0	16.0	$1,002.0
3166	HVAC Equipment	Ductless AC	SF	N/A	NC	1,324.3	15%	198.3	0.334	0.000	0.00	0	16.0	16.0	$1,002.0
3167	HVAC Equipment	Ductless AC	MH	N/A	MO	1,103.6	15%	165.2	0.279	0.000	0.00	0	16.0	16.0	$835.0
3168	HVAC Equipment	Ductless AC	MH	N/A	NC	1,103.6	15%	165.2	0.279	0.000	0.00	0	16.0	16.0	$835.0
3169	HVAC Equipment	Ductless AC (1-ton offset)	SF	N/A	MO	1,324.3	5%	66.1	0.111	0.000	0.00	0	16.0	16.0	$334.0
3170	HVAC Equipment	Ductless AC (1-ton offset)	SF	N/A	NC	1,324.3	5%	66.1	0.111	0.000	0.00	0	16.0	16.0	$334.0
3171	HVAC Equipment	Ductless AC (1-ton offset)	MH	N/A	MO	1,103.6	6%	66.1	0.111	0.000	0.00	0	16.0	16.0	$334.0
3172	HVAC Equipment	Ductless AC (1-ton offset)	MH	N/A	NC	1,103.6	6%	66.1	0.111	0.000	0.00	0	16.0	16.0	$334.0
3173	HVAC Equipment	Smart Thermostat - Heat pump baseline	SF	N/A	Retrofit	5,074.0	8%	430.0	0.240	0.077	0.00	0	11.0	11.0	$129.0
3174	HVAC Equipment	Smart Thermostat - Heat pump baseline	SF	N/A	NC	5,074.0	8%	430.0	0.240	0.077	0.00	0	11.0	11.0	$129.0
3175	HVAC Equipment	Smart Thermostat - Heat pump baseline	MH	N/A	Retrofit	4,228.3	8%	358.3	0.200	0.064	0.00	0	11.0	11.0	$129.0
3176	HVAC Equipment	Smart Thermostat - Heat pump baseline	MH	N/A	NC	4,228.3	8%	358.3	0.200	0.064	0.00	0	11.0	11.0	$129.0
3177	HVAC Equipment	Smart Thermostat - Electric Furnace baseline	SF	N/A	Retrofit	10,838.5	8%	920.0	0.240	0.165	0.00	0	11.0	11.0	$129.0
3178	HVAC Equipment	Smart Thermostat - Electric Furnace baseline	SF	N/A	NC	10,838.5	8%	920.0	0.240	0.165	0.00	0	11.0	11.0	$129.0
3179	HVAC Equipment	Smart Thermostat - Electric Furnace baseline	MH	N/A	Retrofit	9,032.1	8%	766.6	0.200	0.138	0.00	0	11.0	11.0	$129.0
3180	HVAC Equipment	Smart Thermostat - Electric Furnace baseline	MH	N/A	NC	9,032.1	8%	766.6	0.200	0.138	0.00	0	11.0	11.0	$129.0
3181	HVAC Equipment	Smart Thermostat - Gas/CAC baseline	SF	N/A	Retrofit	2,094.7	5%	111.2	0.240	0.001	6.62	0	11.0	11.0	$129.0
3182	HVAC Equipment	Smart Thermostat - Gas/CAC baseline	SF	N/A	NC	2,094.7	5%	111.2	0.240	0.001	6.62	0	11.0	11.0	$129.0
3183	HVAC Equipment	Smart Thermostat - Gas/CAC baseline	MH	N/A	Retrofit	1,873.9	5%	92.7	0.200	0.001	6.62	0	11.0	11.0	$129.0
3184	HVAC Equipment	Smart Thermostat - Gas/CAC baseline	MH	N/A	NC	1,873.9	5%	92.7	0.200	0.001	6.62	0	11.0	11.0	$129.0
3185	HVAC Equipment	ENERGY STAR Room Air Conditioner	SF	N/A	MO	499.4	9%	44.1	0.034	0.000	0.00	0	12.0	12.0	$40.0
3186	HVAC Equipment	ENERGY STAR Room Air Conditioner	SF	N/A	NC	499.4	9%	44.1	0.034	0.000	0.00	0	12.0	12.0	$40.0
3187	HVAC Equipment	ENERGY STAR Room Air Conditioner	MH	N/A	MO	499.4	9%	44.1	0.034	0.000	0.00	0	12.0	12.0	$40.0
3188	HVAC Equipment	ENERGY STAR Room Air Conditioner	MH	N/A	NC	499.4	9%	44.1	0.034	0.000	0.00	0	12.0	12.0	$40.0
3189	HVAC Equipment	Room Air Conditioner Recycling	SF	N/A	Recycle	335.7	100%	335.7	0.260	0.000	0.00	0	4.0	4.0	$64.9
3190	HVAC Equipment	Room Air Conditioner Recycling	MH	N/A	Recycle	335.7	100%	335.7	0.260	0.000	0.00	0	4.0	4.0	$64.9
4001	Lighting	9W LED	SF	N/A	MO	7.6	37%	2.8	0.000	0.001	0.00	0	20.0	20.0	$1.5
4002	Lighting	9W LED	SF	N/A	NC	7.6	37%	2.8	0.000	0.001	0.00	0	20.0	20.0	$1.5
4003	Lighting	9W LED	MH	N/A	MO	7.6	37%	2.8	0.000	0.001	0.00	0	20.0	20.0	$1.5
4004	Lighting	9W LED	MH	N/A	NC	7.6	37%	2.8	0.000	0.001	0.00	0	20.0	20.0	$1.5
4005	Lighting	13W LED	SF	N/A	MO	10.9	31%	3.4	0.000	0.001	0.00	0	20.0	20.0	$1.5
4006	Lighting	13W LED	SF	N/A	NC	10.9	31%	3.4	0.000	0.001	0.00	0	20.0	20.0	$1.5
4007	Lighting	13W LED	MH	N/A	MO	10.9	31%	3.4	0.000	0.001	0.00	0	20.0	20.0	$1.5
4008	Lighting	13W LED	MH	N/A	NC	10.9	31%	3.4	0.000	0.001	0.00	0	20.0	20.0	$1.5
4009	Lighting	LED 5W Globe	SF	N/A	MO	11.8	44%	5.2	0.006	0.001	0.00	0	20.0	20.0	$1.7
4010	Lighting	LED 5W Globe	SF	N/A	NC	11.8	44%	5.2	0.006	0.001	0.00	0	20.0	20.0	$1.7
4011	Lighting	LED 5W Globe	MH	N/A	MO	11.8	44%	5.2	0.006	0.001	0.00	0	20.0	20.0	$1.7
4012	Lighting	LED 5W Globe	MH	N/A	NC	11.8	44%	5.2	0.006	0.001	0.00	0	20.0	20.0	$1.7
4013	Lighting	LED R30 Dimmable	SF	N/A	MO	11.8	57%	6.7	0.008	0.002	0.00	0	20.0	20.0	$1.7
4014	Lighting	LED R30 Dimmable	SF	N/A	NC	11.8	57%	6.7	0.008	0.002	0.00	0	20.0	20.0	$1.7

Big Rivers — **Measure Assumption Tab**

Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW	Per unit NG Saving	Per Unit Water Savings	RC EUL	EE EUL	Initial Measure Cost
4015	Lighting	LED R30 Dimmable	MH	N/A	MO	11.8	57%	6.7	0.008	0.002	0.00	0	20.0	20.0	$1.7
4016	Lighting	LED R30 Dimmable	MH	N/A	NC	11.8	57%	6.7	0.008	0.002	0.00	0	20.0	20.0	$1.7
4017	Lighting	LED Nightlights	SF	N/A	MO	26.0	85%	22.0	0.000	0.005	0.00	0	12.0	12.0	$3.4
4018	Lighting	LED Nightlights	SF	N/A	NC	26.0	85%	22.0	0.000	0.005	0.00	0	12.0	12.0	$3.4
4019	Lighting	LED Nightlights	MH	N/A	MO	26.0	85%	22.0	0.000	0.005	0.00	0	12.0	12.0	$3.4
4020	Lighting	LED Nightlights	MH	N/A	NC	26.0	85%	22.0	0.000	0.005	0.00	0	12.0	12.0	$3.4
4021	Lighting	Exterior LED Lamp	SF	N/A	MO	60.5	57%	34.6	0.000	0.006	0.00	0	2.0	4.0	$1.7
4022	Lighting	Exterior LED Lamp	SF	N/A	NC	60.5	57%	34.6	0.000	0.006	0.00	0	2.0	4.0	$1.7
4023	Lighting	Exterior LED Lamp	MH	N/A	MO	60.5	57%	34.6	0.000	0.006	0.00	0	2.0	4.0	$1.7
4024	Lighting	Exterior LED Lamp	MH	N/A	NC	60.5	57%	34.6	0.000	0.006	0.00	0	2.0	4.0	$1.7
4025	Lighting	Linear LED	SF	N/A	MO	40.6	45%	18.1	0.002	0.004	0.00	0	4.0	10.0	$10.0
4026	Lighting	Linear LED	SF	N/A	NC	40.6	45%	18.1	0.002	0.004	0.00	0	4.0	10.0	$10.0
4027	Lighting	Linear LED	MH	N/A	MO	40.6	45%	18.1	0.002	0.004	0.00	0	4.0	10.0	$10.0
4028	Lighting	Linear LED	MH	N/A	NC	40.6	45%	18.1	0.002	0.004	0.00	0	4.0	10.0	$10.0
4029	Lighting	LED Fixture	SF	N/A	MO	86.9	75%	64.9	0.009	0.016	0.00	0	10.0	20.0	$26.0
4030	Lighting	LED Fixture	SF	N/A	NC	86.9	75%	64.9	0.009	0.016	0.00	0	10.0	20.0	$26.0
4031	Lighting	LED Fixture	MH	N/A	MO	86.9	75%	64.9	0.009	0.016	0.00	0	10.0	20.0	$26.0
4032	Lighting	LED Fixture	MH	N/A	NC	86.9	75%	64.9	0.009	0.016	0.00	0	10.0	20.0	$26.0
4033	Lighting	Occupancy Sensor	SF	N/A	Retrofit	302.2	30%	89.4	0.008	0.022	0.00	0	10.0	10.0	$30.0
4034	Lighting	Occupancy Sensor	SF	N/A	NC	302.2	30%	89.4	0.008	0.022	0.00	0	10.0	10.0	$30.0
4035	Lighting	Occupancy Sensor	MH	N/A	Retrofit	302.2	30%	89.4	0.008	0.022	0.00	0	10.0	10.0	$30.0
4036	Lighting	Occupancy Sensor	MH	N/A	NC	302.2	30%	89.4	0.008	0.022	0.00	0	10.0	10.0	$30.0
4037	Lighting	Exterior Lighting Controls	SF	N/A	Retrofit	108.0	80%	86.4	0.000	0.015	0.00	0	10.0	10.0	$3.0
4038	Lighting	Exterior Lighting Controls	SF	N/A	NC	108.0	80%	86.4	0.000	0.015	0.00	0	10.0	10.0	$3.0
4039	Lighting	Exterior Lighting Controls	MH	N/A	Retrofit	108.0	80%	86.4	0.000	0.015	0.00	0	10.0	10.0	$3.0
4040	Lighting	Exterior Lighting Controls	MH	N/A	NC	108.0	80%	86.4	0.000	0.015	0.00	0	10.0	10.0	$3.0
5001	Pool/Pump	Heat Pump Pool Heater	SF	N/A	MO	14,584.9	71%	10,417.8	0.000	1.520	0.00	0	15.0	15.0	$1,916.0
5002	Pool/Pump	Heat Pump Pool Heater	SF	N/A	NC	14,584.9	71%	10,417.8	0.000	1.520	0.00	0	15.0	15.0	$1,916.0
5003	Pool/Pump	Heat Pump Pool Heater	MH	N/A	MO	14,584.9	71%	10,417.8	0.000	1.520	0.00	0	15.0	15.0	$1,916.0
5004	Pool/Pump	Heat Pump Pool Heater	MH	N/A	NC	14,584.9	71%	10,417.8	0.000	1.520	0.00	0	15.0	15.0	$1,916.0
5005	Pool/Pump	Variable Speed Pool Pump	SF	N/A	MO	1,167.0	26%	307.7	0.215	0.042	0.00	0	7.0	7.0	$314.0
5006	Pool/Pump	Variable Speed Pool Pump	SF	N/A	NC	1,167.0	26%	307.7	0.215	0.042	0.00	0	7.0	7.0	$314.0
5007	Pool/Pump	Variable Speed Pool Pump	MH	N/A	MO	1,167.0	26%	307.7	0.215	0.042	0.00	0	7.0	7.0	$314.0
5008	Pool/Pump	Variable Speed Pool Pump	MH	N/A	NC	1,167.0	26%	307.7	0.215	0.042	0.00	0	7.0	7.0	$314.0
5009	Pool/Pump	Well Pump	SF	N/A	MO	411.2	33%	135.7	0.015	0.023	0.00	0	20.0	20.0	$110.0
5010	Pool/Pump	Well Pump	SF	N/A	NC	411.2	33%	135.7	0.015	0.023	0.00	0	20.0	20.0	$110.0
5011	Pool/Pump	Well Pump	MH	N/A	MO	411.2	33%	135.7	0.015	0.023	0.00	0	20.0	20.0	$110.0
5012	Pool/Pump	Well Pump	MH	N/A	NC	411.2	33%	135.7	0.015	0.000	0.00	0	20.0	20.0	$110.0
6001	New Construction	New Construction - 15% more efficient (w/AC only)	SF	N/A	NC	12,067.5	15%	1,810.1	0.367	0.072	6.17	0	20.0	20.0	$990.0
6002	New Construction	New Construction - 15% more efficient (w/Elec. HP)	SF	N/A	NC	14,766.1	15%	2,214.9	0.321	0.659	0.00	0	20.0	20.0	$761.0
6003	New Construction	New Construction - 30% more efficient (w/AC only)	SF	N/A	NC	12,067.5	30%	3,620.3	0.733	0.144	12.34	0	20.0	20.0	$1,980.0
6004	New Construction	New Construction - 30% more efficient (w/Elec. HP)	SF	N/A	NC	14,766.1	30%	4,429.8	0.643	1.318	0.00	0	20.0	20.0	$1,522.0
6005	New Construction	New Construction - 15% more efficient (w/AC only)	MH	N/A	NC	9,870.7	15%	1,480.6	0.331	0.062	6.04	0	20.0	20.0	$990.0
6006	New Construction	New Construction - 15% more efficient (w/Elec. HP)	MH	N/A	NC	12,747.2	15%	1,912.1	0.307	0.601	0.00	0	20.0	20.0	$761.0
6007	New Construction	New Construction - 30% more efficient (w/AC only)	MH	N/A	NC	9,870.7	30%	2,961.2	0.663	0.124	12.08	0	20.0	20.0	$1,980.0
6008	New Construction	New Construction - 30% more efficient (w/Elec. HP)	MH	N/A	NC	12,747.2	30%	3,824.2	0.614	1.202	0.00	0	20.0	20.0	$1,522.0
7001	Plug Load	Smart Power Strips - Tier 1	SF	N/A	Retrofit	466.0	12%	56.5	0.006	0.006	0.00	0	7.0	7.0	$10.0
7002	Plug Load	Smart Power Strips - Tier 1	SF	N/A	NC	466.0	12%	56.5	0.006	0.006	0.00	0	7.0	7.0	$10.0
7003	Plug Load	Smart Power Strips - Tier 1	MH	N/A	Retrofit	466.0	12%	56.5	0.006	0.006	0.00	0	7.0	7.0	$10.0
7004	Plug Load	Smart Power Strips - Tier 1	MH	N/A	NC	466.0	12%	56.5	0.006	0.006	0.00	0	7.0	7.0	$10.0
7005	Plug Load	Smart Power Strips - Tier 2	SF	N/A	Retrofit	466.0	29%	136.1	0.015	0.015	0.00	0	7.0	7.0	$20.0
7006	Plug Load	Smart Power Strips - Tier 2	SF	N/A	NC	466.0	29%	136.1	0.015	0.015	0.00	0	7.0	7.0	$20.0

Big Rivers — **Measure Assumption Tab**

Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW	Per unit NG Saving	Per Unit Water Savings	RC EUL	EE EUL	Initial Measure Cost
7007	Plug Load	Smart Power Strips - Tier 2	MH	N/A	Retrofit	466.0	29%	136.1	0.015	0.015	0.00	0	7.0	7.0	$20.0
7008	Plug Load	Smart Power Strips - Tier 2	MH	N/A	NC	466.0	29%	136.1	0.015	0.015	0.00	0	7.0	7.0	$20.0
7009	Plug Load	ENERGY STAR TV	SF	N/A	Retrofit	456.5	20%	91.3	0.011	0.013	0.00	0	5.0	5.0	$60.0
7010	Plug Load	ENERGY STAR TV	SF	N/A	NC	456.5	20%	91.3	0.011	0.013	0.00	0	5.0	5.0	$60.0
7011	Plug Load	ENERGY STAR TV	MH	N/A	Retrofit	456.5	20%	91.3	0.011	0.013	0.00	0	5.0	5.0	$60.0
7012	Plug Load	ENERGY STAR TV	MH	N/A	NC	456.5	20%	91.3	0.011	0.013	0.00	0	5.0	5.0	$60.0
8001	Shell	Duct Sealing - Inadequate Sealing - Heat pump	SF	N/A	Retrofit	5,074.0	14%	728.8	0.243	0.131	0.00	0	20.0	20.0	$738.0
8002	Shell	Duct Sealing - Inadequate Sealing - Heat pump	MH	N/A	Retrofit	4,228.3	17%	728.8	0.243	0.131	0.00	0	20.0	20.0	$491.4
8003	Shell	Duct Sealing - Inadequate Sealing - Electric furnace	SF	N/A	Retrofit	10,838.5	10%	1,130.1	0.243	0.203	0.00	0	20.0	20.0	$738.0
8004	Shell	Duct Sealing - Inadequate Sealing - Electric furnace	MH	N/A	Retrofit	9,032.1	13%	1,130.1	0.243	0.203	0.00	0	20.0	20.0	$491.4
8005	Shell	Duct Sealing - Inadequate Sealing - Gas Heating	SF	N/A	Retrofit	2,094.7	9%	186.4	0.243	0.002	7.37	0	20.0	20.0	$738.0
8006	Shell	Duct Sealing - Inadequate Sealing - Gas Heating	MH	N/A	Retrofit	1,873.9	10%	186.4	0.243	0.002	8.23	0	20.0	20.0	$491.4
8007	Shell	Wall Insulation - Heat pump	SF	N/A	Retrofit	5,074.0	25%	1,256.6	0.123	0.226	0.00	0	30.0	30.0	$1,574.3
8008	Shell	Wall Insulation - Heat pump	MH	N/A	Retrofit	4,228.3	16%	687.5	0.067	0.123	0.00	0	30.0	30.0	$861.3
8009	Shell	Wall Insulation - Electric furnace	SF	N/A	Retrofit	10,838.5	18%	1,989.5	0.123	0.357	0.00	0	30.0	30.0	$1,574.3
8010	Shell	Wall Insulation - Electric furnace	MH	N/A	Retrofit	9,032.1	12%	1,088.4	0.067	0.195	0.00	0	30.0	30.0	$861.3
8011	Shell	Wall Insulation - Gas Heating	SF	N/A	Retrofit	2,094.7	17%	348.2	0.123	0.004	13.76	0	30.0	30.0	$1,574.3
8012	Shell	Wall Insulation - Gas Heating	MH	N/A	Retrofit	1,873.9	12%	227.6	0.067	0.002	10.06	0	30.0	30.0	$861.3
8013	Shell	Air Sealing Inadequate Sealing - Heat pump	SF	N/A	Retrofit	5,074.0	19%	986.5	0.429	0.177	0.00	0	20.0	20.0	$1,479.7
8014	Shell	Air Sealing Inadequate Sealing - Heat pump	MH	N/A	Retrofit	4,228.3	23%	986.5	0.429	0.177	0.00	0	20.0	20.0	$986.2
8015	Shell	Air Sealing Inadequate Sealing - Electric furnace	SF	N/A	Retrofit	10,838.5	14%	1,473.0	0.429	0.265	0.00	0	20.0	20.0	$1,479.7
8016	Shell	Air Sealing Inadequate Sealing - Electric furnace	MH	N/A	Retrofit	9,032.1	16%	1,473.0	0.429	0.265	0.00	0	20.0	20.0	$986.2
8017	Shell	Air Sealing - Inadequate Sealing - Gas Heating	SF	N/A	Retrofit	2,094.7	19%	400.7	0.429	0.004	15.84	0	20.0	20.0	$1,479.7
8018	Shell	Air Sealing - Inadequate Sealing - Gas Heating	MH	N/A	Retrofit	1,873.9	21%	400.7	0.429	0.004	17.70	0	20.0	20.0	$986.2
8019	Shell	Attic Insulation - Inadequate Insulation - Heat pump	SF	N/A	Retrofit	5,074.0	10%	486.1	0.117	0.087	0.00	0	30.0	30.0	$1,270.5
8020	Shell	Attic Insulation - Inadequate Insulation - Electric furnace	SF	N/A	Retrofit	10,838.5	7%	769.6	0.117	0.138	0.00	0	30.0	30.0	$1,270.5
8021	Shell	Attic Insulation - Inadequate Insulation - Gas Heating	SF	N/A	Retrofit	2,094.7	15%	312.5	0.117	0.003	12.35	0	30.0	30.0	$1,270.5
8022	Shell	Radiant Barrier - Heat pump	SF	N/A	Retrofit	5,074.0	11%	554.4	0.000	0.000	0.00	0	25.0	25.0	$496.7
8023	Shell	Radiant Barrier - Electric furnace	SF	N/A	Retrofit	10,838.5	5%	554.4	0.000	0.000	0.00	0	25.0	25.0	$496.7
8024	Shell	Radiant Barrier - Gas furnace	SF	N/A	Retrofit	2,094.7	26%	554.4	0.000	0.000	0.00	0	25.0	25.0	$496.7
8025	Shell	Cool Roof - Heat pump	SF	N/A	Retrofit	2,094.7	1%	28.3	0.005	0.005	0.00	0	20.0	20.0	$508.7
8026	Shell	Cool Roof - Electric furnace	SF	N/A	Retrofit	2,094.7	1%	28.3	0.005	0.005	0.00	0	20.0	20.0	$508.7
8027	Shell	Cool Roof - Gas furnace	SF	N/A	Retrofit	2,094.7	1%	28.3	0.013	0.000	1.12	0	20.0	20.0	$508.7
8028	Shell	ENERGY STAR Windows - Heat pump	SF	N/A	Retrofit	5,074.0	40%	2,052.0	0.370	0.369	0.00	0	20.0	20.0	$2,986.4
8029	Shell	ENERGY STAR Windows - Heat pump	MH	N/A	Retrofit	4,228.3	32%	1,370.3	0.247	0.246	0.00	0	20.0	20.0	$1,893.6
8030	Shell	ENERGY STAR Windows - Electric furnace	SF	N/A	Retrofit	10,838.5	47%	5,125.4	0.923	0.921	0.00	0	20.0	20.0	$2,986.4
8031	Shell	ENERGY STAR Windows - Electric furnace	MH	N/A	Retrofit	9,032.1	38%	3,422.6	0.616	0.615	0.00	0	20.0	20.0	$1,893.6
8032	Shell	ENERGY STAR Windows - Gas Heating	SF	N/A	Retrofit	2,094.7	15%	322.2	0.149	0.003	12.74	0	20.0	20.0	$2,986.4
8033	Shell	ENERGY STAR Windows - Gas Heating	MH	N/A	Retrofit	1,873.9	13%	244.5	0.113	0.003	10.80	0	20.0	20.0	$1,893.6
8034	Shell	Basement Sidewall Insulation - Heat pump	SF	N/A	Retrofit	5,074.0	17%	881.9	0.159	0.158	0.00	0	30.0	30.0	$5,171.4
8035	Shell	Basement Sidewall Insulation - Electric furnace	SF	N/A	Retrofit	10,838.5	14%	1,534.5	0.276	0.276	0.00	0	30.0	30.0	$5,171.4
8036	Shell	Basement Sidewall Insulation - Gas Heating	SF	N/A	Retrofit	2,094.7	3%	69.9	0.027	0.003	3.73	0	30.0	30.0	$5,171.4
8037	Shell	Floor Insulation Above Crawlspace - Heat pump	SF	N/A	Retrofit	5,074.0	22%	1,091.4	0.197	0.196	0.00	0	30.0	30.0	$981.8
8038	Shell	Floor Insulation Above Crawlspace - Heat pump	MH	N/A	Retrofit	4,228.3	26%	1,091.4	0.197	0.196	0.00	0	30.0	30.0	$981.8
8039	Shell	Floor Insulation Above Crawlspace - Electric furnace	SF	N/A	Retrofit	10,838.5	17%	1,791.7	0.323	0.322	0.00	0	30.0	30.0	$981.8
8040	Shell	Floor Insulation Above Crawlspace - Electric furnace	MH	N/A	Retrofit	9,032.1	20%	1,791.7	0.323	0.322	0.00	0	30.0	30.0	$981.8
8041	Shell	Floor Insulation Above Crawlspace - Gas Heating	SF	N/A	Retrofit	2,094.7	10%	206.3	0.095	0.002	8.15	0	30.0	30.0	$981.8
8042	Shell	Floor Insulation Above Crawlspace - Gas Heating	MH	N/A	Retrofit	1,873.9	11%	206.3	0.095	0.002	9.11	0	30.0	30.0	$981.8
8043	Shell	ENERGY STAR Door - Heat pump	SF	N/A	Retrofit	5,074.0	5%	275.6	0.050	0.049	0.00	0	20.0	20.0	$1,275.0
8044	Shell	ENERGY STAR Door - Heat pump	MH	N/A	Retrofit	4,228.3	7%	275.6	0.050	0.049	0.00	0	20.0	20.0	$1,275.0
8045	Shell	ENERGY STAR Door - Electric furnace	SF	N/A	Retrofit	10,838.5	2%	196.4	0.035	0.035	0.00	0	20.0	20.0	$1,275.0
8046	Shell	ENERGY STAR Door - Electric furnace	MH	N/A	Retrofit	9,032.1	2%	196.4	0.035	0.035	0.00	0	20.0	20.0	$1,275.0

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Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW	Per unit NG Saving	Per Unit Water Savings	RC EUL	EE EUL	Initial Measure Cost
8047	Shell	ENERGY STAR Door - Gas Heating	SF	N/A	Retrofit	2,094.7	1%	20.1	0.009	0.000	0.79	0	20.0	20.0	$1,275.0
8048	Shell	ENERGY STAR Door - Gas Heating	MH	N/A	Retrofit	1,873.9	1%	20.1	0.009	0.000	0.89	0	20.0	20.0	$1,275.0
9001	Water Heating	Pipe Wrap	SF	N/A	Retrofit	3,242.3	8%	246.7	0.010	0.010	0.00	0	15.0	15.0	$18.0
9002	Water Heating	Pipe Wrap	SF	N/A	NC	3,242.3	8%	246.7	0.010	0.010	0.00	0	15.0	15.0	$18.0
9003	Water Heating	Pipe Wrap	MH	N/A	Retrofit	3,242.3	8%	246.7	0.010	0.010	0.00	0	15.0	15.0	$18.0
9004	Water Heating	Pipe Wrap	MH	N/A	NC	3,242.3	8%	246.7	0.010	0.010	0.00	0	15.0	15.0	$18.0
9005	Water Heating	Bathroom Aerator 1.0 gpm	SF	N/A	Retrofit	3,242.3	1%	34.7	0.048	0.007	0.00	404	10.0	10.0	$3.0
9006	Water Heating	Bathroom Aerator 1.0 gpm	SF	N/A	NC	3,242.3	1%	34.7	0.048	0.007	0.00	404	10.0	10.0	$3.0
9007	Water Heating	Bathroom Aerator 1.0 gpm	MH	N/A	Retrofit	3,242.3	1%	34.7	0.048	0.007	0.00	404	10.0	10.0	$3.0
9008	Water Heating	Bathroom Aerator 1.0 gpm	MH	N/A	NC	3,242.3	1%	34.7	0.048	0.007	0.00	404	10.0	10.0	$3.0
9009	Water Heating	Kitchen Flip Aerator 1.5 gpm	SF	N/A	Retrofit	3,242.3	8%	269.0	0.053	0.053	0.00	2,025	10.0	10.0	$3.0
9010	Water Heating	Kitchen Flip Aerator 1.5 gpm	SF	N/A	NC	3,242.3	8%	269.0	0.053	0.053	0.00	2,025	10.0	10.0	$3.0
9011	Water Heating	Kitchen Flip Aerator 1.5 gpm	MH	N/A	Retrofit	3,242.3	8%	269.0	0.053	0.053	0.00	2,025	10.0	10.0	$3.0
9012	Water Heating	Kitchen Flip Aerator 1.5 gpm	MH	N/A	NC	3,242.3	8%	269.0	0.053	0.053	0.00	2,025	10.0	10.0	$3.0
9013	Water Heating	Low Flow Showerhead 1.5 gpm	SF	N/A	Retrofit	3,242.3	7%	217.0	0.022	0.022	0.00	1,737	10.0	10.0	$7.0
9014	Water Heating	Low Flow Showerhead 1.5 gpm	SF	N/A	NC	3,242.3	7%	217.0	0.022	0.022	0.00	1,737	10.0	10.0	$7.0
9015	Water Heating	Low Flow Showerhead 1.5 gpm	MH	N/A	Retrofit	3,242.3	7%	217.0	0.022	0.022	0.00	1,737	10.0	10.0	$7.0
9016	Water Heating	Low Flow Showerhead 1.5 gpm	MH	N/A	NC	3,242.3	7%	217.0	0.022	0.022	0.00	1,737	10.0	10.0	$7.0
9017	Water Heating	Thermostatic Restrictor Shower Valve	SF	N/A	Retrofit	3,242.3	2%	76.5	0.005	0.005	0.00	643	10.0	10.0	$30.0
9018	Water Heating	Thermostatic Restrictor Shower Valve	SF	N/A	NC	3,242.3	2%	76.5	0.005	0.005	0.00	643	10.0	10.0	$30.0
9019	Water Heating	Thermostatic Restrictor Shower Valve	MH	N/A	Retrofit	3,242.3	2%	76.5	0.005	0.005	0.00	643	10.0	10.0	$30.0
9020	Water Heating	Thermostatic Restrictor Shower Valve	MH	N/A	NC	3,242.3	2%	76.5	0.005	0.005	0.00	643	10.0	10.0	$30.0
9021	Water Heating	Heat Pump Water Heater (UEF 2.0)-electric resistance heat	SF	N/A	MO	2,942.2	61%	1,783.5	0.084	0.620	0.00	0	13.0	15.0	$1,030.0
9022	Water Heating	Heat Pump Water Heater (UEF 2.0)-electric resistance heat	SF	N/A	NC	2,942.2	61%	1,783.5	0.084	0.620	0.00	0	13.0	15.0	$1,030.0
9023	Water Heating	Heat Pump Water Heater (UEF 2.0)-electric resistance heat	MH	N/A	MO	2,942.2	56%	1,635.5	0.077	0.568	0.00	0	13.0	15.0	$1,030.0
9024	Water Heating	Heat Pump Water Heater (UEF 2.0)-electric resistance heat	MH	N/A	NC	3,242.3	50%	1,635.5	0.077	0.568	0.00	0	13.0	15.0	$1,030.0
9025	Water Heating	Heat Pump Water Heater (UEF 2.0)-heat pump heat	SF	N/A	MO	2,659.7	67%	1,790.9	0.085	0.622	0.00	0	13.0	15.0	$1,030.0
9026	Water Heating	Heat Pump Water Heater (UEF 2.0)-heat pump heat	SF	N/A	NC	2,659.7	67%	1,790.9	0.085	0.622	0.00	0	13.0	15.0	$1,030.0
9027	Water Heating	Heat Pump Water Heater (UEF 2.0)-heat pump heat	MH	N/A	MO	3,242.3	51%	1,642.3	0.078	0.571	0.00	0	13.0	15.0	$1,030.0
9028	Water Heating	Heat Pump Water Heater (UEF 2.0)-heat pump heat	MH	N/A	NC	3,242.3	51%	1,642.3	0.078	0.571	0.00	0	13.0	15.0	$1,030.0
9029	Water Heating	Heat Pump Water Heater (UEF 2.0)-gas heat	SF	N/A	MO	2,659.7	68%	1,799.7	0.085	0.625	40.35	0	13.0	15.0	$1,030.0
9030	Water Heating	Heat Pump Water Heater (UEF 2.0)-gas heat	SF	N/A	NC	2,659.7	68%	1,799.7	0.085	0.625	40.35	0	13.0	15.0	$1,030.0
9031	Water Heating	Heat Pump Water Heater (UEF 2.0)-gas heat	MH	N/A	MO	3,242.3	51%	1,650.3	0.078	0.573	24.51	0	13.0	15.0	$1,030.0
9032	Water Heating	Heat Pump Water Heater (UEF 2.0)-gas heat	MH	N/A	MO	3,242.3	51%	1,650.3	0.078	0.573	24.51	0	13.0	15.0	$1,030.0
9033	Water Heating	Heat Pump Water Heater (UEF 2.6)-electric resistance heat	SF	N/A	MO	2,659.7	80%	2,120.2	0.100	0.737	0.00	0	13.0	15.0	$1,199.0
9034	Water Heating	Heat Pump Water Heater (UEF 2.6)-electric resistance heat	SF	N/A	NC	2,659.7	80%	2,120.2	0.100	0.737	0.00	0	13.0	15.0	$1,199.0
9035	Water Heating	Heat Pump Water Heater (UEF 2.6)-electric resistance heat	MH	N/A	MO	3,242.3	60%	1,944.2	0.092	0.675	0.00	0	13.0	15.0	$1,199.0
9036	Water Heating	Heat Pump Water Heater (UEF 2.6)-electric resistance heat	MH	N/A	NC	3,242.3	60%	1,944.2	0.092	0.675	0.00	0	13.0	15.0	$1,199.0
9037	Water Heating	Heat Pump Water Heater (UEF 2.6)-heat pump heat	SF	N/A	MO	2,659.7	80%	2,129.2	0.101	0.740	0.00	0	13.0	15.0	$1,199.0
9038	Water Heating	Heat Pump Water Heater (UEF 2.6)-heat pump heat	SF	N/A	NC	2,659.7	80%	2,129.2	0.101	0.740	0.00	0	13.0	15.0	$1,199.0
9039	Water Heating	Heat Pump Water Heater (UEF 2.6)-heat pump heat	MH	N/A	MO	3,242.3	60%	1,952.5	0.092	0.678	0.00	0	13.0	15.0	$1,199.0
9040	Water Heating	Heat Pump Water Heater (UEF 2.6)-heat pump heat	MH	N/A	NC	3,242.3	60%	1,952.5	0.092	0.678	0.00	0	13.0	15.0	$1,199.0
9041	Water Heating	Heat Pump Water Heater (UEF 2.6)-gas heat	SF	N/A	MO	2,659.7	80%	2,140.1	0.101	0.744	47.99	0	13.0	15.0	$1,199.0
9042	Water Heating	Heat Pump Water Heater (UEF 2.6)-gas heat	SF	N/A	NC	2,659.7	80%	2,140.1	0.101	0.744	47.99	0	13.0	15.0	$1,199.0
9043	Water Heating	Heat Pump Water Heater (UEF 2.6)-gas heat	MH	N/A	MO	3,242.3	61%	1,962.5	0.093	0.682	29.15	0	13.0	15.0	$1,199.0
9044	Water Heating	Heat Pump Water Heater (UEF 2.6)-gas heat	MH	N/A	MO	3,242.3	61%	1,962.5	0.093	0.682	29.15	0	13.0	15.0	$1,199.0
9045	Water Heating	Water Heater Wrap	SF	N/A	Retrofit	3,242.3	8%	245.7	0.028	0.333	0.00	0	5.0	5.0	$64.5
9046	Water Heating	Water Heater Wrap	SF	N/A	NC	3,242.3	8%	245.7	0.028	0.333	0.00	0	5.0	5.0	$64.5
9047	Water Heating	Water Heater Wrap	MH	N/A	Retrofit	3,242.3	8%	245.7	0.028	0.333	0.00	0	5.0	5.0	$64.5
9048	Water Heating	Water Heater Wrap	MH	N/A	NC	3,242.3	8%	245.7	0.028	0.333	0.00	0	5.0	5.0	$64.5
9049	Water Heating	Drain water Heat Recovery	SF	N/A	Retrofit	3,242.3	19%	600.5	0.006	0.006	0.00	0	30.0	30.0	$744.0
9050	Water Heating	Drain water Heat Recovery	SF	N/A	NC	3,242.3	19%	600.5	0.006	0.006	0.00	0	30.0	30.0	$744.0

Big Rivers — **Measure Assumption Tab**

Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW	Per unit NG Saving	Per Unit Water Savings	RC EUL	EE EUL	Initial Measure Cost
9051	Water Heating	Drain water Heat Recovery	MH	N/A	Retrofit	3,242.3	19%	600.5	0.006	0.006	0.00	0	30.0	30.0	$744.0
9052	Water Heating	Drain water Heat Recovery	MH	N/A	NC	3,242.3	19%	600.5	0.006	0.006	0.00	0	30.0	30.0	$744.0
9053	Water Heating	Shower Timer	SF	N/A	Retrofit	3,242.3	3%	81.4	0.038	0.064	0.00	740	2.0	2.0	$26.0
9054	Water Heating	Shower Timer	SF	N/A	NC	3,242.3	3%	81.4	0.038	0.064	0.00	740	2.0	2.0	$26.0
9055	Water Heating	Shower Timer	MH	N/A	Retrofit	3,242.3	3%	81.4	0.038	0.057	0.00	740	2.0	2.0	$26.0
9056	Water Heating	Shower Timer	MH	N/A	NC	3,242.3	3%	81.4	0.038	0.057	0.00	740	2.0	2.0	$26.0
9057	Cross-Cutting	Multi-Family Homes Efficiency Kit	MF	N/A	Retrofit	9,460.0	2%	233.0	0.027	0.027	0.00	0	7.0	7.0	$75.63
9058	Cross-Cutting	Multi-Family Homes Efficiency Kit	MF	N/A	NC	9,460.0	2%	233.0	0.027	0.027	0.00	0	7.0	7.0	$75.63

Big Rivers — **Measure Benefit-Cost Ratios**

Measure #	End-Use	Measure Name	Measure Designation	Home Type	Income Type	Replacement Type	TRC BC Ratio	Societal	UCT	Participant	RIM
1001	Appliances	ENERGY STAR Refrigerator	Electric	SF	N/A	MO	0.94	0.94	1.57	3.11	0.30
1002	Appliances	ENERGY STAR Refrigerator	Electric	SF	N/A	NC	0.94	0.94	1.57	3.11	0.30
1003	Appliances	ENERGY STAR Refrigerator	Electric	MH	N/A	MO	0.94	0.94	1.57	3.11	0.30
1004	Appliances	ENERGY STAR Refrigerator	Electric	MH	N/A	NC	0.94	0.94	1.57	3.11	0.30
1005	Appliances	CEE Tier 2 Refrigerator	Electric	SF	N/A	MO	0.37	0.37	0.61	1.54	0.24
1006	Appliances	CEE Tier 2 Refrigerator	Electric	SF	N/A	NC	0.37	0.37	0.61	1.54	0.24
1007	Appliances	CEE Tier 2 Refrigerator	Electric	MH	N/A	MO	0.37	0.37	0.61	1.54	0.24
1008	Appliances	CEE Tier 2 Refrigerator	Electric	MH	N/A	NC	0.37	0.37	0.61	1.54	0.24
1009	Appliances	CEE Tier 3 Refrigerator	Electric	SF	N/A	MO	0.42	0.42	0.70	1.65	0.25
1010	Appliances	CEE Tier 3 Refrigerator	Electric	SF	N/A	NC	0.42	0.42	0.70	1.65	0.25
1011	Appliances	CEE Tier 3 Refrigerator	Electric	MH	N/A	MO	0.42	0.42	0.70	1.65	0.25
1012	Appliances	CEE Tier 3 Refrigerator	Electric	MH	N/A	NC	0.42	0.42	0.70	1.65	0.25
1013	Appliances	Refrigerator Recycling	Electric	SF	N/A	Recycle	1.97	1.97	3.29	5.99	0.33
1014	Appliances	Refrigerator Recycling	Electric	MH	N/A	Recycle	1.97	1.97	3.29	5.99	0.33
1015	Appliances	ENERGY STAR Clothes Washer	Electric	SF	N/A	MO	2.62	2.62	1.80	5.18	0.30
1016	Appliances	ENERGY STAR Clothes Washer	Electric	SF	N/A	NC	2.62	2.62	1.80	5.18	0.30
1017	Appliances	ENERGY STAR Clothes Washer	Electric	MH	N/A	MO	2.62	2.62	1.80	5.18	0.30
1018	Appliances	ENERGY STAR Clothes Washer	Electric	MH	N/A	NC	2.62	2.62	1.80	5.18	0.30
1019	Appliances	ENERGY STAR Clothes Washer (CEE Tier 2)	Electric	SF	N/A	MO	4.49	4.49	3.36	8.75	0.32
1020	Appliances	ENERGY STAR Clothes Washer (CEE Tier 2)	Electric	SF	N/A	NC	4.49	4.49	3.36	8.75	0.32
1021	Appliances	ENERGY STAR Clothes Washer (CEE Tier 2)	Electric	MH	N/A	MO	4.49	4.49	3.36	8.75	0.32
1022	Appliances	ENERGY STAR Clothes Washer (CEE Tier 2)	Electric	MH	N/A	NC	4.49	4.49	3.36	8.75	0.32
1023	Appliances	ENERGY STAR Clothes Washer (CEE Tier 3)	Electric	SF	N/A	MO	4.18	4.18	3.12	8.17	0.32
1024	Appliances	ENERGY STAR Clothes Washer (CEE Tier 3)	Electric	SF	N/A	NC	4.18	4.18	3.12	8.17	0.32
1025	Appliances	ENERGY STAR Clothes Washer (CEE Tier 3)	Electric	MH	N/A	MO	4.18	4.18	3.12	8.17	0.32
1026	Appliances	ENERGY STAR Clothes Washer (CEE Tier 3)	Electric	MH	N/A	NC	4.18	4.18	3.12	8.17	0.32
1027	Appliances	ENERGY STAR Dishwasher	Electric	SF	N/A	MO	0.50	0.50	0.36	1.69	0.15
1028	Appliances	ENERGY STAR Dishwasher	Electric	SF	N/A	NC	0.50	0.50	0.36	1.69	0.15
1029	Appliances	ENERGY STAR Dishwasher	Electric	MH	N/A	MO	0.50	0.50	0.36	1.69	0.15
1030	Appliances	ENERGY STAR Dishwasher	Electric	MH	N/A	NC	0.50	0.50	0.36	1.69	0.15
1031	Appliances	ENERGY STAR Dehumidifier	Electric	SF	N/A	MO	3.26	3.26	5.44	6.94	0.47
1032	Appliances	ENERGY STAR Dehumidifier	Electric	SF	N/A	NC	3.26	3.26	5.44	6.94	0.47
1033	Appliances	ENERGY STAR Dehumidifier	Electric	MH	N/A	MO	3.26	3.26	5.44	6.94	0.47
1034	Appliances	ENERGY STAR Dehumidifier	Electric	MH	N/A	NC	3.26	3.26	5.44	6.94	0.47
1035	Appliances	ENERGY STAR Most Efficient Dehumidifier	Electric	SF	N/A	MO	1.63	1.63	2.71	3.71	0.44
1036	Appliances	ENERGY STAR Most Efficient Dehumidifier	Electric	SF	N/A	NC	1.63	1.63	2.71	3.71	0.44
1037	Appliances	ENERGY STAR Most Efficient Dehumidifier	Electric	MH	N/A	MO	1.63	1.63	2.71	3.71	0.44
1038	Appliances	ENERGY STAR Most Efficient Dehumidifier	Electric	MH	N/A	NC	1.63	1.63	2.71	3.71	0.44
1039	Appliances	ENERGY STAR Freezer	Electric	SF	N/A	MO	5.08	5.08	8.47	14.74	0.34
1040	Appliances	ENERGY STAR Freezer	Electric	SF	N/A	NC	5.08	5.08	8.47	14.74	0.34
1041	Appliances	ENERGY STAR Freezer	Electric	MH	N/A	MO	5.08	5.08	8.47	14.74	0.34
1042	Appliances	ENERGY STAR Freezer	Electric	MH	N/A	NC	5.08	5.08	8.47	14.74	0.34
1043	Appliances	Freezer Recycling	Electric	SF	N/A	Recycle	1.85	1.85	3.08	6.02	0.31
1044	Appliances	Freezer Recycling	Electric	MH	N/A	Recycle	1.85	1.85	3.08	6.02	0.31
1045	Appliances	ENERGY STAR Clothes Dryer	Electric	SF	N/A	MO	0.80	0.80	1.34	2.83	0.28
1046	Appliances	ENERGY STAR Clothes Dryer	Electric	SF	N/A	NC	0.80	0.80	1.34	2.83	0.28
1047	Appliances	ENERGY STAR Clothes Dryer	Electric	MH	N/A	MO	0.80	0.80	1.34	2.83	0.28
1048	Appliances	ENERGY STAR Clothes Dryer	Electric	MH	N/A	NC	0.80	0.80	1.34	2.83	0.28
2001	Behavioral	Home Energy Management System	Electric	SF	N/A	MO	1.84	1.84	3.06	5.72	0.32
2002	Behavioral	Home Energy Management System	Electric	SF	N/A	NC	1.84	1.84	3.06	5.72	0.32
2003	Behavioral	Home Energy Management System	Electric	MH	N/A	MO	1.84	1.84	3.06	5.72	0.32
2004	Behavioral	Home Energy Management System	Electric	MH	N/A	NC	1.84	1.84	3.06	5.72	0.32
2005	Behavioral	Online Energy Audit	Electric	SF	N/A	MO	2.39	2.39	3.98	6.71	0.36
2006	Behavioral	Online Energy Audit	Electric	SF	N/A	NC	2.39	2.39	3.98	6.71	0.36
2007	Behavioral	Online Energy Audit	Electric	MH	N/A	MO	2.39	2.39	3.98	6.71	0.36
2008	Behavioral	Online Energy Audit	Electric	MH	N/A	NC	2.39	2.39	3.98	6.71	0.36
3001	HVAC Equipment	ASHP Tune Up	Electric	SF	N/A	Retrofit	0.38	0.38	0.64	1.11	0.35
3002	HVAC Equipment	ASHP Tune Up	Electric	SF	N/A	NC	0.38	0.38	0.64	1.11	0.35
3003	HVAC Equipment	ASHP Tune Up	Electric	MH	N/A	Retrofit	0.32	0.32	0.53	1.03	0.31
3004	HVAC Equipment	ASHP Tune Up	Electric	MH	N/A	NC	0.32	0.32	0.53	1.03	0.31
3005	HVAC Equipment	Air Source Heat Pump 15.2 SEER2 - Heat pump baseline	Electric	SF	N/A	MO	0.82	0.82	1.37	2.29	0.36
3006	HVAC Equipment	Air Source Heat Pump 15.2 SEER2 - Heat pump baseline	Electric	SF	N/A	NC	0.82	0.82	1.37	2.29	0.36
3007	HVAC Equipment	Air Source Heat Pump 15.2 SEER2 - Heat pump baseline	Electric	MH	N/A	MO	0.82	0.82	1.37	2.29	0.36
3008	HVAC Equipment	Air Source Heat Pump 15.2 SEER2 - Heat pump baseline	Electric	MH	N/A	NC	0.82	0.82	1.37	2.29	0.36
3009	HVAC Equipment	Air Source Heat Pump 16.2 SEER2 - Heat pump baseline	Electric	SF	N/A	MO	0.76	0.76	1.26	2.08	0.36
3010	HVAC Equipment	Air Source Heat Pump 16.2 SEER2 - Heat pump baseline	Electric	SF	N/A	NC	0.76	0.76	1.26	2.08	0.36
3011	HVAC Equipment	Air Source Heat Pump 16.2 SEER2 - Heat pump baseline	Electric	MH	N/A	MO	0.76	0.76	1.26	2.08	0.36
3012	HVAC Equipment	Air Source Heat Pump 16.2 SEER2 - Heat pump baseline	Electric	MH	N/A	NC	0.76	0.76	1.26	2.08	0.36
3013	HVAC Equipment	Air Source Heat Pump 17.1 SEER2 - Heat pump baseline	Electric	SF	N/A	MO	0.73	0.73	1.22	2.07	0.35

Big Rivers — **Measure Benefit-Cost Ratios**

Measure #	End-Use	Measure Name	Measure Designation	Home Type	Income Type	Replacement Type	TRC BC Ratio	Societal	UCT	Participant	RIM
3014	HVAC Equipment	Air Source Heat Pump 17.1 SEER2 - Heat pump baseline	Electric	SF	N/A	NC	0.73	0.73	1.22	2.07	0.35
3015	HVAC Equipment	Air Source Heat Pump 17.1 SEER2 - Heat pump baseline	Electric	MH	N/A	MO	0.73	0.73	1.22	2.07	0.35
3016	HVAC Equipment	Air Source Heat Pump 17.1 SEER2 - Heat pump baseline	Electric	MH	N/A	NC	0.73	0.73	1.22	2.07	0.35
3017	HVAC Equipment	Air Source Heat Pump 18.1 SEER2 - Heat pump baseline	Electric	SF	N/A	MO	2.08	2.08	3.46	1.92	1.08
3018	HVAC Equipment	Air Source Heat Pump 18.1 SEER2 - Heat pump baseline	Electric	SF	N/A	NC	2.08	2.08	3.46	1.92	1.08
3019	HVAC Equipment	Air Source Heat Pump 18.1 SEER2 - Heat pump baseline	Electric	MH	N/A	MO	2.08	2.08	3.46	1.92	1.08
3020	HVAC Equipment	Air Source Heat Pump 18.1 SEER2 - Heat pump baseline	Electric	MH	N/A	NC	2.08	2.08	3.46	1.92	1.08
3021	HVAC Equipment	Air Source Heat Pump 19 SEER2 - Heat pump baseline	Electric	SF	N/A	MO	1.90	1.90	3.16	1.80	1.06
3022	HVAC Equipment	Air Source Heat Pump 19 SEER2 - Heat pump baseline	Electric	SF	N/A	NC	1.90	1.90	3.16	1.80	1.06
3023	HVAC Equipment	Air Source Heat Pump 19 SEER2 - Heat pump baseline	Electric	MH	N/A	MO	1.90	1.90	3.16	1.80	1.06
3024	HVAC Equipment	Air Source Heat Pump 19 SEER2 - Heat pump baseline	Electric	MH	N/A	NC	1.90	1.90	3.16	1.80	1.06
3025	HVAC Equipment	Air Source Heat Pump 20 SEER2 - Heat pump baseline	Electric	SF	N/A	MO	1.76	1.76	2.94	1.70	1.03
3026	HVAC Equipment	Air Source Heat Pump 20 SEER2 - Heat pump baseline	Electric	SF	N/A	NC	1.76	1.76	2.94	1.70	1.03
3027	HVAC Equipment	Air Source Heat Pump 20 SEER2 - Heat pump baseline	Electric	MH	N/A	MO	1.76	1.76	2.94	1.71	1.03
3028	HVAC Equipment	Air Source Heat Pump 20 SEER2 - Heat pump baseline	Electric	MH	N/A	NC	1.76	1.76	2.94	1.71	1.03
3029	HVAC Equipment	Ground Source Heat Pump 20 SEER - Heat pump baseline	Electric	SF	N/A	MO	0.72	0.72	1.19	2.04	0.35
3030	HVAC Equipment	Ground Source Heat Pump 20 SEER - Heat pump baseline	Electric	SF	N/A	NC	0.72	0.72	1.19	2.04	0.35
3031	HVAC Equipment	Ground Source Heat Pump 20 SEER - Heat pump baseline	Electric	MH	N/A	MO	1.14	1.14	1.91	2.91	0.39
3032	HVAC Equipment	Ground Source Heat Pump 20 SEER - Heat pump baseline	Electric	MH	N/A	NC	1.14	1.14	1.91	2.91	0.39
3033	HVAC Equipment	Ground Source Heat Pump 21.5 SEER - Heat pump baseline	Electric	SF	N/A	MO	0.74	0.74	1.23	2.09	0.35
3034	HVAC Equipment	Ground Source Heat Pump 21.5 SEER - Heat pump baseline	Electric	SF	N/A	NC	0.74	0.74	1.23	2.09	0.35
3035	HVAC Equipment	Ground Source Heat Pump 21.5 SEER - Heat pump baseline	Electric	MH	N/A	MO	1.18	1.18	1.97	2.98	0.40
3036	HVAC Equipment	Ground Source Heat Pump 21.5 SEER - Heat pump baseline	Electric	MH	N/A	NC	1.18	1.18	1.97	2.98	0.40
3037	HVAC Equipment	Ground Source Heat Pump 23.5 SEER - Heat pump baseline	Electric	SF	N/A	MO	0.76	0.76	1.27	2.14	0.36
3038	HVAC Equipment	Ground Source Heat Pump 23.5 SEER - Heat pump baseline	Electric	SF	N/A	NC	0.76	0.76	1.27	2.14	0.36
3039	HVAC Equipment	Ground Source Heat Pump 23.5 SEER - Heat pump baseline	Electric	MH	N/A	MO	1.22	1.22	2.04	3.06	0.40
3040	HVAC Equipment	Ground Source Heat Pump 23.5 SEER - Heat pump baseline	Electric	MH	N/A	NC	1.22	1.22	2.04	3.06	0.40
3041	HVAC Equipment	Ground Source Heat Pump 29 SEER - Heat pump baseline	Electric	SF	N/A	MO	0.82	0.82	1.36	2.24	0.36
3042	HVAC Equipment	Ground Source Heat Pump 29 SEER - Heat pump baseline	Electric	SF	N/A	NC	0.82	0.82	1.36	2.24	0.36
3043	HVAC Equipment	Ground Source Heat Pump 29 SEER - Heat pump baseline	Electric	MH	N/A	MO	1.30	1.30	2.17	3.23	0.40
3044	HVAC Equipment	Ground Source Heat Pump 29 SEER - Heat pump baseline	Electric	MH	N/A	NC	1.30	1.30	2.17	3.23	0.40
3045	HVAC Equipment	Ductless Heat Pump 8.5 HSPF2 - Heat pump baseline	Electric	SF	N/A	MO	2.96	2.96	4.94	6.71	0.44
3046	HVAC Equipment	Ductless Heat Pump 8.5 HSPF2 - Heat pump baseline	Electric	SF	N/A	NC	2.96	2.96	4.94	6.71	0.44
3047	HVAC Equipment	Ductless Heat Pump 8.5 HSPF2 - Heat pump baseline	Electric	MH	N/A	MO	2.96	2.96	4.94	6.71	0.44
3048	HVAC Equipment	Ductless Heat Pump 8.5 HSPF2 - Heat pump baseline	Electric	MH	N/A	NC	2.96	2.96	4.94	6.71	0.44
3049	HVAC Equipment	Ductless Heat Pump 9.4 HSPF2 - Heat pump baseline	Electric	SF	N/A	MO	1.51	1.51	2.52	3.57	0.42
3050	HVAC Equipment	Ductless Heat Pump 9.4 HSPF2 - Heat pump baseline	Electric	SF	N/A	NC	1.51	1.51	2.52	3.57	0.42
3051	HVAC Equipment	Ductless Heat Pump 9.4 HSPF2 - Heat pump baseline	Electric	MH	N/A	MO	1.51	1.51	2.52	3.57	0.42
3052	HVAC Equipment	Ductless Heat Pump 9.4 HSPF2 - Heat pump baseline	Electric	MH	N/A	NC	1.51	1.51	2.52	3.57	0.42
3053	HVAC Equipment	Ductless Heat Pump 10.8 HSPF2 - Heat pump baseline	Electric	SF	N/A	MO	1.47	1.47	2.46	3.57	0.41
3054	HVAC Equipment	Ductless Heat Pump 10.8 HSPF2 - Heat pump baseline	Electric	SF	N/A	NC	1.47	1.47	2.46	3.57	0.41
3055	HVAC Equipment	Ductless Heat Pump 10.8 HSPF2 - Heat pump baseline	Electric	MH	N/A	MO	1.47	1.47	2.46	3.57	0.41
3056	HVAC Equipment	Ductless Heat Pump 10.8 HSPF2 - Heat pump baseline	Electric	MH	N/A	NC	1.47	1.47	2.46	3.57	0.41
3057	HVAC Equipment	Ductless Heat Pump 11.7 HSPF2 - Heat pump baseline	Electric	SF	N/A	MO	0.91	0.91	1.51	2.39	0.38
3058	HVAC Equipment	Ductless Heat Pump 11.7 HSPF2 - Heat pump baseline	Electric	SF	N/A	NC	0.91	0.91	1.51	2.39	0.38
3059	HVAC Equipment	Ductless Heat Pump 11.7 HSPF2 - Heat pump baseline	Electric	MH	N/A	MO	0.91	0.91	1.51	2.39	0.38
3060	HVAC Equipment	Ductless Heat Pump 11.7 HSPF2 - Heat pump baseline	Electric	MH	N/A	NC	0.91	0.91	1.51	2.39	0.38
3061	HVAC Equipment	Ductless Heat Pump 8.5 HSPF2 - Heat pump baseline (1-ton offset)	Electric	SF	N/A	MO	2.96	2.96	4.94	6.71	0.44
3062	HVAC Equipment	Ductless Heat Pump 8.5 HSPF2 - Heat pump baseline (1-ton offset)	Electric	SF	N/A	NC	2.96	2.96	4.94	6.71	0.44
3063	HVAC Equipment	Ductless Heat Pump 8.5 HSPF2 - Heat pump baseline (1-ton offset)	Electric	MH	N/A	MO	2.96	2.96	4.94	6.71	0.44
3064	HVAC Equipment	Ductless Heat Pump 8.5 HSPF2 - Heat pump baseline (1-ton offset)	Electric	MH	N/A	NC	2.96	2.96	4.94	6.71	0.44
3065	HVAC Equipment	Ductless Heat Pump 9.4 HSPF2 - Heat pump baseline (1-ton offset)	Electric	SF	N/A	MO	1.51	1.51	2.52	3.57	0.42
3066	HVAC Equipment	Ductless Heat Pump 9.4 HSPF2 - Heat pump baseline (1-ton offset)	Electric	SF	N/A	NC	1.51	1.51	2.52	3.57	0.42
3067	HVAC Equipment	Ductless Heat Pump 9.4 HSPF2 - Heat pump baseline (1-ton offset)	Electric	MH	N/A	MO	1.51	1.51	2.52	3.57	0.42
3068	HVAC Equipment	Ductless Heat Pump 9.4 HSPF2 - Heat pump baseline (1-ton offset)	Electric	MH	N/A	NC	1.51	1.51	2.52	3.57	0.42
3069	HVAC Equipment	Ductless Heat Pump 10.8 HSPF2 - Heat pump baseline (1-ton offset)	Electric	SF	N/A	MO	1.47	1.47	2.46	3.57	0.41
3070	HVAC Equipment	Ductless Heat Pump 10.8 HSPF2 - Heat pump baseline (1-ton offset)	Electric	SF	N/A	NC	1.47	1.47	2.46	3.57	0.41
3071	HVAC Equipment	Ductless Heat Pump 10.8 HSPF2 - Heat pump baseline (1-ton offset)	Electric	MH	N/A	MO	1.47	1.47	2.46	3.57	0.41
3072	HVAC Equipment	Ductless Heat Pump 10.8 HSPF2 - Heat pump baseline (1-ton offset)	Electric	MH	N/A	NC	1.47	1.47	2.46	3.57	0.41
3073	HVAC Equipment	Ductless Heat Pump 11.7 HSPF2 - Heat pump baseline (1-ton offset)	Electric	SF	N/A	MO	0.91	0.91	1.51	2.39	0.38
3074	HVAC Equipment	Ductless Heat Pump 11.7 HSPF2 - Heat pump baseline (1-ton offset)	Electric	SF	N/A	NC	0.91	0.91	1.51	2.39	0.38
3075	HVAC Equipment	Ductless Heat Pump 11.7 HSPF2 - Heat pump baseline (1-ton offset)	Electric	MH	N/A	MO	0.91	0.91	1.51	2.39	0.38
3076	HVAC Equipment	Ductless Heat Pump 11.7 HSPF2 - Heat pump baseline (1-ton offset)	Electric	MH	N/A	NC	0.91	0.91	1.51	2.39	0.38
3077	HVAC Equipment	Air Source Heat Pump 15.2 SEER2 - Electric furnace baseline	Electric	SF	N/A	MO	6.42	6.42	10.71	21.73	0.30
3078	HVAC Equipment	Air Source Heat Pump 15.2 SEER2 - Electric furnace baseline	Electric	SF	N/A	NC	6.42	6.42	10.71	21.73	0.30
3079	HVAC Equipment	Air Source Heat Pump 15.2 SEER2 - Electric furnace baseline	Electric	MH	N/A	MO	6.42	6.42	10.71	21.73	0.30
3080	HVAC Equipment	Air Source Heat Pump 15.2 SEER2 - Electric furnace baseline	Electric	MH	N/A	NC	6.42	6.42	10.71	21.73	0.30
3081	HVAC Equipment	Air Source Heat Pump 16.2 SEER2 - Electric furnace baseline	Electric	SF	N/A	MO	3.56	3.56	5.93	11.79	0.30
3082	HVAC Equipment	Air Source Heat Pump 16.2 SEER2 - Electric furnace baseline	Electric	SF	N/A	NC	3.56	3.56	5.93	11.79	0.30

Big Rivers — **Measure Benefit-Cost Ratios**

Measure #	End-Use	Measure Name	Measure Designation	Home Type	Income Type	Replacement Type	TRC BC Ratio	Societal	UCT	Participant	RIM
3083	HVAC Equipment	Air Source Heat Pump 16.2 SEER2 - Electric furnace baseline	Electric	MH	N/A	MO	3.56	3.56	5.93	11.79	0.30
3084	HVAC Equipment	Air Source Heat Pump 16.2 SEER2 - Electric furnace baseline	Electric	MH	N/A	NC	3.56	3.56	5.93	11.79	0.30
3085	HVAC Equipment	Air Source Heat Pump 17.1 SEER2 - Electric furnace baseline	Electric	SF	N/A	MO	2.60	2.60	4.33	8.55	0.30
3086	HVAC Equipment	Air Source Heat Pump 17.1 SEER2 - Electric furnace baseline	Electric	SF	N/A	NC	2.60	2.60	4.33	8.55	0.30
3087	HVAC Equipment	Air Source Heat Pump 17.1 SEER2 - Electric furnace baseline	Electric	MH	N/A	MO	2.60	2.60	4.33	8.55	0.30
3088	HVAC Equipment	Air Source Heat Pump 17.1 SEER2 - Electric furnace baseline	Electric	MH	N/A	NC	2.60	2.60	4.33	8.55	0.30
3089	HVAC Equipment	Air Source Heat Pump 18.1 SEER2 - Electric furnace baseline	Electric	SF	N/A	MO	4.30	4.30	7.16	6.77	0.63
3090	HVAC Equipment	Air Source Heat Pump 18.1 SEER2 - Electric furnace baseline	Electric	SF	N/A	NC	4.30	4.30	7.16	6.77	0.63
3091	HVAC Equipment	Air Source Heat Pump 18.1 SEER2 - Electric furnace baseline	Electric	MH	N/A	MO	4.30	4.30	7.16	6.77	0.63
3092	HVAC Equipment	Air Source Heat Pump 18.1 SEER2 - Electric furnace baseline	Electric	MH	N/A	NC	4.30	4.30	7.16	6.77	0.63
3093	HVAC Equipment	Air Source Heat Pump 19 SEER2 - Electric furnace baseline	Electric	SF	N/A	MO	3.57	3.57	5.96	5.68	0.63
3094	HVAC Equipment	Air Source Heat Pump 19 SEER2 - Electric furnace baseline	Electric	SF	N/A	NC	3.57	3.57	5.96	5.68	0.63
3095	HVAC Equipment	Air Source Heat Pump 19 SEER2 - Electric furnace baseline	Electric	MH	N/A	MO	3.57	3.57	5.96	5.68	0.63
3096	HVAC Equipment	Air Source Heat Pump 19 SEER2 - Electric furnace baseline	Electric	MH	N/A	NC	3.57	3.57	5.96	5.68	0.63
3097	HVAC Equipment	Air Source Heat Pump 20 SEER2 - Electric furnace baseline	Electric	SF	N/A	MO	3.08	3.08	5.14	4.94	0.62
3098	HVAC Equipment	Air Source Heat Pump 20 SEER2 - Electric furnace baseline	Electric	SF	N/A	NC	3.08	3.08	5.14	4.94	0.62
3099	HVAC Equipment	Air Source Heat Pump 20 SEER2 - Electric furnace baseline	Electric	MH	N/A	MO	3.08	3.08	5.14	4.94	0.62
3100	HVAC Equipment	Air Source Heat Pump 20 SEER2 - Electric furnace baseline	Electric	MH	N/A	NC	3.08	3.08	5.14	4.94	0.62
3101	HVAC Equipment	Ductless Heat Pump 8.5 HSPF2 - Electric resistance baseline	Electric	SF	N/A	MO	23.25	23.25	38.75	77.08	0.30
3102	HVAC Equipment	Ductless Heat Pump 8.5 HSPF2 - Electric resistance baseline	Electric	SF	N/A	NC	23.25	23.25	38.75	77.08	0.30
3103	HVAC Equipment	Ductless Heat Pump 8.5 HSPF2 - Electric resistance baseline	Electric	MH	N/A	MO	23.25	23.25	38.75	77.08	0.30
3104	HVAC Equipment	Ductless Heat Pump 8.5 HSPF2 - Electric resistance baseline	Electric	MH	N/A	NC	23.25	23.25	38.75	77.08	0.30
3105	HVAC Equipment	Ductless Heat Pump 9.4 HSPF2 - Electric resistance baseline	Electric	SF	N/A	MO	7.13	7.13	11.88	23.05	0.31
3106	HVAC Equipment	Ductless Heat Pump 9.4 HSPF2 - Electric resistance baseline	Electric	SF	N/A	NC	7.13	7.13	11.88	23.05	0.31
3107	HVAC Equipment	Ductless Heat Pump 9.4 HSPF2 - Electric resistance baseline	Electric	MH	N/A	MO	7.13	7.13	11.88	23.05	0.31
3108	HVAC Equipment	Ductless Heat Pump 9.4 HSPF2 - Electric resistance baseline	Electric	MH	N/A	NC	7.13	7.13	11.88	23.05	0.31
3109	HVAC Equipment	Ductless Heat Pump 10.8 HSPF2 - Electric resistance baseline	Electric	SF	N/A	MO	5.24	5.24	8.73	16.64	0.31
3110	HVAC Equipment	Ductless Heat Pump 10.8 HSPF2 - Electric resistance baseline	Electric	SF	N/A	NC	5.24	5.24	8.73	16.64	0.31
3111	HVAC Equipment	Ductless Heat Pump 10.8 HSPF2 - Electric resistance baseline	Electric	MH	N/A	MO	5.24	5.24	8.73	16.64	0.31
3112	HVAC Equipment	Ductless Heat Pump 10.8 HSPF2 - Electric resistance baseline	Electric	MH	N/A	NC	5.24	5.24	8.73	16.64	0.31
3113	HVAC Equipment	Ductless Heat Pump 11.7 HSPF2 - Electric resistance baseline	Electric	SF	N/A	MO	2.81	2.81	4.69	9.00	0.31
3114	HVAC Equipment	Ductless Heat Pump 11.7 HSPF2 - Electric resistance baseline	Electric	SF	N/A	NC	2.81	2.81	4.69	9.00	0.31
3115	HVAC Equipment	Ductless Heat Pump 11.7 HSPF2 - Electric resistance baseline	Electric	MH	N/A	MO	2.81	2.81	4.69	9.00	0.31
3116	HVAC Equipment	Ductless Heat Pump 11.7 HSPF2 - Electric resistance baseline	Electric	MH	N/A	NC	2.81	2.81	4.69	9.00	0.31
3117	HVAC Equipment	Ductless Heat Pump 8.5 HSPF2 - Electric resistance baseline (1-ton offset	Electric	SF	N/A	MO	23.25	23.25	38.75	77.08	0.30
3118	HVAC Equipment	Ductless Heat Pump 8.5 HSPF2 - Electric resistance baseline (1-ton offset	Electric	SF	N/A	NC	23.25	23.25	38.75	77.08	0.30
3119	HVAC Equipment	Ductless Heat Pump 8.5 HSPF2 - Electric resistance baseline (1-ton offset	Electric	MH	N/A	MO	23.25	23.25	38.75	77.08	0.30
3120	HVAC Equipment	Ductless Heat Pump 8.5 HSPF2 - Electric resistance baseline (1-ton offset	Electric	MH	N/A	NC	23.25	23.25	38.75	77.08	0.30
3121	HVAC Equipment	Ductless Heat Pump 9.4 HSPF2 - Electric resistance baseline (1-ton offset	Electric	SF	N/A	MO	7.13	7.13	11.88	23.05	0.31
3122	HVAC Equipment	Ductless Heat Pump 9.4 HSPF2 - Electric resistance baseline (1-ton offset	Electric	SF	N/A	NC	7.13	7.13	11.88	23.05	0.31
3123	HVAC Equipment	Ductless Heat Pump 9.4 HSPF2 - Electric resistance baseline (1-ton offset	Electric	MH	N/A	MO	7.13	7.13	11.88	23.05	0.31
3124	HVAC Equipment	Ductless Heat Pump 9.4 HSPF2 - Electric resistance baseline (1-ton offset	Electric	MH	N/A	NC	7.13	7.13	11.88	23.05	0.31
3125	HVAC Equipment	Ductless Heat Pump 10.8 HSPF2 - Electric resistance baseline (1-ton offse	Electric	SF	N/A	MO	5.24	5.24	8.73	16.64	0.31
3126	HVAC Equipment	Ductless Heat Pump 10.8 HSPF2 - Electric resistance baseline (1-ton offse	Electric	SF	N/A	NC	5.24	5.24	8.73	16.64	0.31
3127	HVAC Equipment	Ductless Heat Pump 10.8 HSPF2 - Electric resistance baseline (1-ton offse	Electric	MH	N/A	MO	5.24	5.24	8.73	16.64	0.31
3128	HVAC Equipment	Ductless Heat Pump 10.8 HSPF2 - Electric resistance baseline (1-ton offse	Electric	MH	N/A	NC	5.24	5.24	8.73	16.64	0.31
3129	HVAC Equipment	Ductless Heat Pump 11.7 HSPF2 - Electric resistance baseline (1-ton offse	Electric	SF	N/A	MO	2.81	2.81	4.69	9.00	0.31
3130	HVAC Equipment	Ductless Heat Pump 11.7 HSPF2 - Electric resistance baseline (1-ton offse	Electric	SF	N/A	NC	2.81	2.81	4.69	9.00	0.31
3131	HVAC Equipment	Ductless Heat Pump 11.7 HSPF2 - Electric resistance baseline (1-ton offse	Electric	MH	N/A	MO	2.81	2.81	4.69	9.00	0.31
3132	HVAC Equipment	Ductless Heat Pump 11.7 HSPF2 - Electric resistance baseline (1-ton offse	Electric	MH	N/A	NC	2.81	2.81	4.69	9.00	0.31
3133	HVAC Equipment	AC Tune Up	Electric	SF	N/A	Retrofit	0.17	0.17	0.28	0.73	0.23
3134	HVAC Equipment	AC Tune Up	Electric	SF	N/A	NC	0.17	0.17	0.28	0.73	0.23
3135	HVAC Equipment	AC Tune Up	Electric	MH	N/A	Retrofit	0.14	0.14	0.24	0.71	0.20
3136	HVAC Equipment	AC Tune Up	Electric	MH	N/A	NC	0.14	0.14	0.24	0.71	0.20
3137	HVAC Equipment	Central Air Conditioner 15.2 SEER2	Electric	SF	N/A	MO	0.40	0.40	0.67	0.87	0.46
3138	HVAC Equipment	Central Air Conditioner 15.2 SEER2	Electric	SF	N/A	NC	0.40	0.40	0.67	0.87	0.46
3139	HVAC Equipment	Central Air Conditioner 15.2 SEER2	Electric	MH	N/A	MO	0.40	0.40	0.67	0.87	0.46
3140	HVAC Equipment	Central Air Conditioner 15.2 SEER2	Electric	MH	N/A	NC	0.40	0.40	0.67	0.87	0.46
3141	HVAC Equipment	Central Air Conditioner 16.2 SEER2	Electric	SF	N/A	MO	0.40	0.40	0.67	0.87	0.46
3142	HVAC Equipment	Central Air Conditioner 16.2 SEER2	Electric	SF	N/A	NC	0.40	0.40	0.67	0.87	0.46
3143	HVAC Equipment	Central Air Conditioner 16.2 SEER2	Electric	MH	N/A	MO	0.40	0.40	0.67	0.87	0.46
3144	HVAC Equipment	Central Air Conditioner 16.2 SEER2	Electric	MH	N/A	NC	0.40	0.40	0.67	0.87	0.46
3145	HVAC Equipment	Central Air Conditioner 17.1 SEER2	Electric	SF	N/A	MO	0.37	0.37	0.62	0.85	0.44
3146	HVAC Equipment	Central Air Conditioner 17.1 SEER2	Electric	SF	N/A	NC	0.37	0.37	0.62	0.85	0.44
3147	HVAC Equipment	Central Air Conditioner 17.1 SEER2	Electric	MH	N/A	MO	0.37	0.37	0.62	0.85	0.44
3148	HVAC Equipment	Central Air Conditioner 17.1 SEER2	Electric	MH	N/A	NC	0.37	0.37	0.62	0.85	0.44
3149	HVAC Equipment	Central Air Conditioner 18.1 SEER2	Electric	SF	N/A	MO	0.36	0.36	0.60	0.84	0.43
3150	HVAC Equipment	Central Air Conditioner 18.1 SEER2	Electric	SF	N/A	NC	0.36	0.36	0.60	0.84	0.43
3151	HVAC Equipment	Central Air Conditioner 18.1 SEER2	Electric	MH	N/A	MO	0.36	0.36	0.60	0.84	0.43

Big Rivers — **Measure Benefit-Cost Ratios**

Measure #	End-Use	Measure Name	Measure Designation	Home Type	Income Type	Replacement Type	TRC BC Ratio	Societal	UCT	Participant	RIM
3152	HVAC Equipment	Central Air Conditioner 18.1 SEER2	Electric	MH	N/A	NC	0.36	0.36	0.60	0.84	0.43
3153	HVAC Equipment	Central Air Conditioner 19 SEER2	Electric	SF	N/A	MO	0.34	0.34	0.56	0.83	0.41
3154	HVAC Equipment	Central Air Conditioner 19 SEER2	Electric	SF	N/A	NC	0.34	0.34	0.56	0.83	0.41
3155	HVAC Equipment	Central Air Conditioner 19 SEER2	Electric	MH	N/A	MO	0.34	0.34	0.56	0.83	0.41
3156	HVAC Equipment	Central Air Conditioner 19 SEER2	Electric	MH	N/A	NC	0.34	0.34	0.56	0.83	0.41
3157	HVAC Equipment	Central Air Conditioner 20 SEER2	Electric	SF	N/A	MO	0.32	0.32	0.54	0.82	0.40
3158	HVAC Equipment	Central Air Conditioner 20 SEER2	Electric	SF	N/A	NC	0.32	0.32	0.54	0.82	0.40
3159	HVAC Equipment	Central Air Conditioner 20 SEER2	Electric	MH	N/A	MO	0.32	0.32	0.54	0.82	0.40
3160	HVAC Equipment	Central Air Conditioner 20 SEER2	Electric	MH	N/A	NC	0.32	0.32	0.54	0.82	0.40
3161	HVAC Equipment	Central Air Conditioner 21 SEER2	Electric	SF	N/A	MO	0.31	0.31	0.52	0.81	0.38
3162	HVAC Equipment	Central Air Conditioner 21 SEER2	Electric	SF	N/A	NC	0.31	0.31	0.52	0.81	0.38
3163	HVAC Equipment	Central Air Conditioner 21 SEER2	Electric	MH	N/A	MO	0.26	0.26	0.43	0.77	0.33
3164	HVAC Equipment	Central Air Conditioner 21 SEER2	Electric	MH	N/A	NC	0.26	0.26	0.43	0.77	0.33
3165	HVAC Equipment	Ductless AC	Electric	SF	N/A	MO	0.63	0.63	1.05	1.02	0.62
3166	HVAC Equipment	Ductless AC	Electric	SF	N/A	NC	0.63	0.63	1.05	1.02	0.62
3167	HVAC Equipment	Ductless AC	Electric	MH	N/A	MO	0.63	0.63	1.05	1.02	0.62
3168	HVAC Equipment	Ductless AC	Electric	MH	N/A	NC	0.63	0.63	1.05	1.02	0.62
3169	HVAC Equipment	Ductless AC (1-ton offset)	Electric	SF	N/A	MO	0.63	0.63	1.05	1.02	0.62
3170	HVAC Equipment	Ductless AC (1-ton offset)	Electric	SF	N/A	NC	0.63	0.63	1.05	1.02	0.62
3171	HVAC Equipment	Ductless AC (1-ton offset)	Electric	MH	N/A	MO	0.63	0.63	1.05	1.02	0.62
3172	HVAC Equipment	Ductless AC (1-ton offset)	Electric	MH	N/A	NC	0.63	0.63	1.05	1.02	0.62
3173	HVAC Equipment	Smart Thermostat - Heat pump baseline	Electric	SF	N/A	Retrofit	3.86	3.86	6.44	5.71	0.68
3174	HVAC Equipment	Smart Thermostat - Heat pump baseline	Electric	SF	N/A	NC	3.86	3.86	6.44	5.71	0.68
3175	HVAC Equipment	Smart Thermostat - Heat pump baseline	Electric	MH	N/A	Retrofit	3.22	3.22	5.37	4.86	0.66
3176	HVAC Equipment	Smart Thermostat - Heat pump baseline	Electric	MH	N/A	NC	3.22	3.22	5.37	4.86	0.66
3177	HVAC Equipment	Smart Thermostat - Electric Furnace baseline	Electric	SF	N/A	Retrofit	5.61	5.61	9.34	11.54	0.49
3178	HVAC Equipment	Smart Thermostat - Electric Furnace baseline	Electric	SF	N/A	NC	5.61	5.61	9.34	11.54	0.49
3179	HVAC Equipment	Smart Thermostat - Electric Furnace baseline	Electric	MH	N/A	Retrofit	4.67	4.67	7.79	9.72	0.48
3180	HVAC Equipment	Smart Thermostat - Electric Furnace baseline	Electric	MH	N/A	NC	4.67	4.67	7.79	9.72	0.48
3181	HVAC Equipment	Smart Thermostat - Gas/CAC baseline	Electric	SF	N/A	Retrofit	2.55	2.55	4.25	1.92	1.32
3182	HVAC Equipment	Smart Thermostat - Gas/CAC baseline	Electric	SF	N/A	NC	2.55	2.55	4.25	1.92	1.32
3183	HVAC Equipment	Smart Thermostat - Gas/CAC baseline	Electric	MH	N/A	Retrofit	2.12	2.12	3.54	1.70	1.25
3184	HVAC Equipment	Smart Thermostat - Gas/CAC baseline	Electric	MH	N/A	NC	2.12	2.12	3.54	1.70	1.25
3185	HVAC Equipment	ENERGY STAR Room Air Conditioner	Electric	SF	N/A	MO	1.43	1.43	2.38	2.42	0.59
3186	HVAC Equipment	ENERGY STAR Room Air Conditioner	Electric	SF	N/A	NC	1.43	1.43	2.38	2.42	0.59
3187	HVAC Equipment	ENERGY STAR Room Air Conditioner	Electric	MH	N/A	MO	1.43	1.43	2.38	2.42	0.59
3188	HVAC Equipment	ENERGY STAR Room Air Conditioner	Electric	MH	N/A	NC	1.43	1.43	2.38	2.42	0.59
3189	HVAC Equipment	Room Air Conditioner Recycling	Electric	SF	N/A	Recycle	2.55	2.55	4.25	3.71	0.69
3190	HVAC Equipment	Room Air Conditioner Recycling	Electric	MH	N/A	Recycle	2.55	2.55	4.25	3.71	0.69
4001	Lighting	9W LED	Electric	SF	N/A	MO	1.97	1.97	3.28	5.51	0.36
4002	Lighting	9W LED	Electric	SF	N/A	NC	1.97	1.97	3.28	5.51	0.36
4003	Lighting	9W LED	Electric	MH	N/A	MO	1.97	1.97	3.28	5.51	0.36
4004	Lighting	9W LED	Electric	MH	N/A	NC	1.97	1.97	3.28	5.51	0.36
4005	Lighting	13W LED	Electric	SF	N/A	MO	2.39	2.39	3.98	6.56	0.36
4006	Lighting	13W LED	Electric	SF	N/A	NC	2.39	2.39	3.98	6.56	0.36
4007	Lighting	13W LED	Electric	MH	N/A	MO	2.39	2.39	3.98	6.56	0.36
4008	Lighting	13W LED	Electric	MH	N/A	NC	2.39	2.39	3.98	6.56	0.36
4009	Lighting	LED 5W Globe	Electric	SF	N/A	MO	10.23	10.23	17.05	8.61	1.19
4010	Lighting	LED 5W Globe	Electric	SF	N/A	NC	10.23	10.23	17.05	8.61	1.19
4011	Lighting	LED 5W Globe	Electric	MH	N/A	MO	10.23	10.23	17.05	8.61	1.19
4012	Lighting	LED 5W Globe	Electric	MH	N/A	NC	10.23	10.23	17.05	8.61	1.19
4013	Lighting	LED R30 Dimmable	Electric	SF	N/A	MO	13.22	13.22	22.04	10.95	1.21
4014	Lighting	LED R30 Dimmable	Electric	SF	N/A	NC	13.22	13.22	22.04	10.95	1.21
4015	Lighting	LED R30 Dimmable	Electric	MH	N/A	MO	13.22	13.22	22.04	10.95	1.21
4016	Lighting	LED R30 Dimmable	Electric	MH	N/A	NC	13.22	13.22	22.04	10.95	1.21
4017	Lighting	LED Nightlights	Electric	SF	N/A	MO	3.78	3.78	6.31	11.48	0.33
4018	Lighting	LED Nightlights	Electric	SF	N/A	NC	3.78	3.78	6.31	11.48	0.33
4019	Lighting	LED Nightlights	Electric	MH	N/A	MO	3.78	3.78	6.31	11.48	0.33
4020	Lighting	LED Nightlights	Electric	MH	N/A	NC	3.78	3.78	6.31	11.48	0.33
4021	Lighting	Exterior LED Lamp	Electric	SF	N/A	MO	4.02	4.02	6.69	13.18	0.30
4022	Lighting	Exterior LED Lamp	Electric	SF	N/A	NC	4.02	4.02	6.69	13.18	0.30
4023	Lighting	Exterior LED Lamp	Electric	MH	N/A	MO	4.02	4.02	6.69	13.18	0.30
4024	Lighting	Exterior LED Lamp	Electric	MH	N/A	NC	4.02	4.02	6.69	13.18	0.30
4025	Lighting	Linear LED	Electric	SF	N/A	MO	1.08	1.08	1.81	3.16	0.34
4026	Lighting	Linear LED	Electric	SF	N/A	NC	1.08	1.08	1.81	3.16	0.34
4027	Lighting	Linear LED	Electric	MH	N/A	MO	1.08	1.08	1.81	3.16	0.34
4028	Lighting	Linear LED	Electric	MH	N/A	NC	1.08	1.08	1.81	3.16	0.34
4029	Lighting	LED Fixture	Electric	SF	N/A	MO	2.79	2.79	4.64	6.95	0.40
4030	Lighting	LED Fixture	Electric	SF	N/A	NC	2.79	2.79	4.64	6.95	0.40

Big Rivers — **Measure Benefit-Cost Ratios**

Measure #	End-Use	Measure Name	Measure Designation	Home Type	Income Type	Replacement Type	TRC BC Ratio	Societal	UCT	Participant	RIM
4031	Lighting	LED Fixture	Electric	MH	N/A	MO	2.79	2.79	4.64	6.95	0.40
4032	Lighting	LED Fixture	Electric	MH	N/A	NC	2.79	2.79	4.64	6.95	0.40
4033	Lighting	Occupancy Sensor	Electric	SF	N/A	Retrofit	1.78	1.78	2.97	4.80	0.37
4034	Lighting	Occupancy Sensor	Electric	SF	N/A	NC	1.78	1.78	2.97	4.80	0.37
4035	Lighting	Occupancy Sensor	Electric	MH	N/A	Retrofit	1.78	1.78	2.97	4.80	0.37
4036	Lighting	Occupancy Sensor	Electric	MH	N/A	NC	1.78	1.78	2.97	4.80	0.37
4037	Lighting	Exterior Lighting Controls	Electric	SF	N/A	Retrofit	12.08	12.08	20.13	41.17	0.29
4038	Lighting	Exterior Lighting Controls	Electric	SF	N/A	NC	12.08	12.08	20.13	41.17	0.29
4039	Lighting	Exterior Lighting Controls	Electric	MH	N/A	Retrofit	12.08	12.08	20.13	41.17	0.29
4040	Lighting	Exterior Lighting Controls	Electric	MH	N/A	NC	12.08	12.08	20.13	41.17	0.29
5001	Pool/Pump	Heat Pump Pool Heater	Electric	SF	N/A	MO	2.87	2.87	4.78	11.51	0.25
5002	Pool/Pump	Heat Pump Pool Heater	Electric	SF	N/A	NC	2.87	2.87	4.78	11.51	0.25
5003	Pool/Pump	Heat Pump Pool Heater	Electric	MH	N/A	MO	2.87	2.87	4.78	11.51	0.25
5004	Pool/Pump	Heat Pump Pool Heater	Electric	MH	N/A	NC	2.87	2.87	4.78	11.51	0.25
5005	Pool/Pump	Variable Speed Pool Pump	Electric	SF	N/A	MO	0.85	0.85	1.42	1.60	0.53
5006	Pool/Pump	Variable Speed Pool Pump	Electric	SF	N/A	NC	0.85	0.85	1.42	1.60	0.53
5007	Pool/Pump	Variable Speed Pool Pump	Electric	MH	N/A	MO	0.85	0.85	1.42	1.60	0.53
5008	Pool/Pump	Variable Speed Pool Pump	Electric	MH	N/A	NC	0.85	0.85	1.42	1.60	0.53
5009	Pool/Pump	Well Pump	Electric	SF	N/A	MO	1.15	1.15	1.91	3.74	0.31
5010	Pool/Pump	Well Pump	Electric	SF	N/A	NC	1.15	1.15	1.91	3.74	0.31
5011	Pool/Pump	Well Pump	Electric	MH	N/A	MO	1.15	1.15	1.91	3.74	0.31
5012	Pool/Pump	Well Pump	Electric	MH	N/A	NC	0.72	0.72	1.21	3.74	0.19
6001	New Construction	New Construction - 15% more efficient (w/AC only)	Electric	SF	N/A	NC	1.55	1.55	2.58	5.25	0.29
6002	New Construction	New Construction - 15% more efficient (w/Elec. HP)	Electric	SF	N/A	NC	3.64	3.64	6.06	8.00	0.45
6003	New Construction	New Construction - 30% more efficient (w/AC only)	Electric	SF	N/A	NC	1.55	1.55	2.58	5.25	0.29
6004	New Construction	New Construction - 30% more efficient (w/Elec. HP)	Electric	SF	N/A	NC	3.64	3.64	6.06	8.00	0.45
6005	New Construction	New Construction - 15% more efficient (w/AC only)	Electric	MH	N/A	NC	1.34	1.34	2.23	4.40	0.30
6006	New Construction	New Construction - 15% more efficient (w/Elec. HP)	Electric	MH	N/A	NC	3.30	3.30	5.50	6.99	0.47
6007	New Construction	New Construction - 30% more efficient (w/AC only)	Electric	MH	N/A	NC	1.34	1.34	2.23	4.40	0.30
6008	New Construction	New Construction - 30% more efficient (w/Elec. HP)	Electric	MH	N/A	NC	3.30	3.30	5.50	6.99	0.47
7001	Plug Load	Smart Power Strips - Tier 1	Electric	SF	N/A	Retrofit	2.00	2.00	3.33	6.35	0.31
7002	Plug Load	Smart Power Strips - Tier 1	Electric	SF	N/A	NC	2.00	2.00	3.33	6.35	0.31
7003	Plug Load	Smart Power Strips - Tier 1	Electric	MH	N/A	Retrofit	2.00	2.00	3.33	6.35	0.31
7004	Plug Load	Smart Power Strips - Tier 1	Electric	MH	N/A	NC	2.00	2.00	3.33	6.35	0.31
7005	Plug Load	Smart Power Strips - Tier 2	Electric	SF	N/A	Retrofit	2.40	2.40	4.01	7.53	0.32
7006	Plug Load	Smart Power Strips - Tier 2	Electric	SF	N/A	NC	2.40	2.40	4.01	7.53	0.32
7007	Plug Load	Smart Power Strips - Tier 2	Electric	MH	N/A	Retrofit	2.40	2.40	4.01	7.53	0.32
7008	Plug Load	Smart Power Strips - Tier 2	Electric	MH	N/A	NC	2.40	2.40	4.01	7.53	0.32
7009	Plug Load	ENERGY STAR TV	Electric	SF	N/A	Retrofit	0.45	0.45	0.75	1.73	0.26
7010	Plug Load	ENERGY STAR TV	Electric	SF	N/A	NC	0.45	0.45	0.75	1.73	0.26
7011	Plug Load	ENERGY STAR TV	Electric	MH	N/A	Retrofit	0.45	0.45	0.75	1.73	0.26
7012	Plug Load	ENERGY STAR TV	Electric	MH	N/A	NC	0.45	0.45	0.75	1.73	0.26
8001	Shell	Duct Sealing - Inadequate Sealing - Heat pump	Electric	SF	N/A	Retrofit	1.37	1.37	2.29	3.11	0.44
8002	Shell	Duct Sealing - Inadequate Sealing - Heat pump	Electric	MH	N/A	Retrofit	2.06	2.06	3.44	4.37	0.47
8003	Shell	Duct Sealing - Inadequate Sealing - Electric furnace	Electric	SF	N/A	Retrofit	1.76	1.76	2.94	4.49	0.39
8004	Shell	Duct Sealing - Inadequate Sealing - Electric furnace	Electric	MH	N/A	Retrofit	2.65	2.65	4.42	6.45	0.41
8005	Shell	Duct Sealing - Inadequate Sealing - Gas Heating	Electric	SF	N/A	Retrofit	0.76	0.76	1.26	1.24	0.61
8006	Shell	Duct Sealing - Inadequate Sealing - Gas Heating	Electric	MH	N/A	Retrofit	1.14	1.14	1.90	1.56	0.73
8007	Shell	Wall Insulation - Heat pump	Electric	SF	N/A	Retrofit	0.96	0.96	1.60	2.63	0.37
8008	Shell	Wall Insulation - Heat pump	Electric	MH	N/A	Retrofit	0.96	0.96	1.60	2.63	0.37
8009	Shell	Wall Insulation - Electric furnace	Electric	SF	N/A	Retrofit	1.40	1.40	2.33	3.81	0.37
8010	Shell	Wall Insulation - Electric furnace	Electric	MH	N/A	Retrofit	1.40	1.40	2.33	3.81	0.37
8011	Shell	Wall Insulation - Gas Heating	Electric	SF	N/A	Retrofit	0.32	0.32	0.53	1.16	0.27
8012	Shell	Wall Insulation - Gas Heating	Electric	MH	N/A	Retrofit	0.34	0.34	0.56	1.27	0.27
8013	Shell	Air Sealing Inadequate Sealing - Heat pump	Electric	SF	N/A	Retrofit	1.06	1.06	1.77	2.30	0.46
8014	Shell	Air Sealing Inadequate Sealing - Heat pump	Electric	MH	N/A	Retrofit	1.60	1.60	2.66	3.14	0.51
8015	Shell	Air Sealing Inadequate Sealing - Electric furnace	Electric	SF	N/A	Retrofit	1.30	1.30	2.17	3.13	0.42
8016	Shell	Air Sealing Inadequate Sealing - Electric furnace	Electric	MH	N/A	Retrofit	1.95	1.95	3.25	4.40	0.44
8017	Shell	Air Sealing - Inadequate Sealing - Gas Heating	Electric	SF	N/A	Retrofit	0.69	0.69	1.14	1.29	0.53
8018	Shell	Air Sealing - Inadequate Sealing - Gas Heating	Electric	MH	N/A	Retrofit	1.03	1.03	1.72	1.63	0.63
8019	Shell	Attic Insulation - Inadequate Insulation - Heat pump	Electric	SF	N/A	Retrofit	0.61	0.61	1.01	1.57	0.39
8020	Shell	Attic Insulation - Inadequate Insulation - Electric furnace	Electric	SF	N/A	Retrofit	0.82	0.82	1.36	2.14	0.38
8021	Shell	Attic Insulation - Inadequate Insulation - Gas Heating	Electric	SF	N/A	Retrofit	0.37	0.37	0.61	1.23	0.30
8022	Shell	Radiant Barrier - Heat pump	Electric	SF	N/A	Retrofit	0.46	0.46	0.77	3.44	0.13
8023	Shell	Radiant Barrier - Electric furnace	Electric	SF	N/A	Retrofit	0.46	0.46	0.77	3.44	0.13
8024	Shell	Radiant Barrier - Gas furnace	Electric	SF	N/A	Retrofit	0.46	0.46	0.77	3.44	0.13
8025	Shell	Cool Roof - Heat pump	Electric	SF	N/A	Retrofit	0.06	0.06	0.10	0.74	0.08
8026	Shell	Cool Roof - Electric furnace	Electric	SF	N/A	Retrofit	0.06	0.06	0.10	0.74	0.08
8027	Shell	Cool Roof - Gas furnace	Electric	SF	N/A	Retrofit	0.07	0.07	0.12	0.74	0.10

Big Rivers — **Measure Benefit-Cost Ratios**

Measure #	End-Use	Measure Name	Measure Designation	Home Type	Income Type	Replacement Type	TRC BC Ratio	Societal	UCT	Participant	RIM
8028	Shell	ENERGY STAR Windows - Heat pump	Electric	SF	N/A	Retrofit	0.74	0.74	1.24	2.35	0.32
8029	Shell	ENERGY STAR Windows - Heat pump	Electric	MH	N/A	Retrofit	0.78	0.78	1.30	2.44	0.32
8030	Shell	ENERGY STAR Windows - Electric furnace	Electric	SF	N/A	Retrofit	1.86	1.86	3.09	4.96	0.37
8031	Shell	ENERGY STAR Windows - Electric furnace	Electric	MH	N/A	Retrofit	1.96	1.96	3.26	5.20	0.38
8032	Shell	ENERGY STAR Windows - Gas Heating	Electric	SF	N/A	Retrofit	0.14	0.14	0.24	0.87	0.16
8033	Shell	ENERGY STAR Windows - Gas Heating	Electric	MH	N/A	Retrofit	0.17	0.17	0.28	0.93	0.18
8034	Shell	Basement Sidewall Insulation - Heat pump	Electric	SF	N/A	Retrofit	0.24	0.24	0.40	1.03	0.23
8035	Shell	Basement Sidewall Insulation - Electric furnace	Electric	SF	N/A	Retrofit	0.42	0.42	0.70	1.35	0.31
8036	Shell	Basement Sidewall Insulation - Gas Heating	Electric	SF	N/A	Retrofit	0.02	0.02	0.04	0.63	0.04
8037	Shell	Floor Insulation Above Crawlspace - Heat pump	Electric	SF	N/A	Retrofit	1.58	1.58	2.64	3.43	0.46
8038	Shell	Floor Insulation Above Crawlspace - Heat pump	Electric	MH	N/A	Retrofit	1.58	1.58	2.64	3.43	0.46
8039	Shell	Floor Insulation Above Crawlspace - Electric furnace	Electric	SF	N/A	Retrofit	2.60	2.60	4.33	5.24	0.50
8040	Shell	Floor Insulation Above Crawlspace - Electric furnace	Electric	MH	N/A	Retrofit	2.60	2.60	4.33	5.24	0.50
8041	Shell	Floor Insulation Above Crawlspace - Gas Heating	Electric	SF	N/A	Retrofit	0.36	0.36	0.60	1.13	0.32
8042	Shell	Floor Insulation Above Crawlspace - Gas Heating	Electric	MH	N/A	Retrofit	0.36	0.36	0.60	1.13	0.32
8043	Shell	ENERGY STAR Door - Heat pump	Electric	SF	N/A	Retrofit	0.23	0.23	0.39	1.15	0.20
8044	Shell	ENERGY STAR Door - Heat pump	Electric	MH	N/A	Retrofit	0.23	0.23	0.39	1.15	0.20
8045	Shell	ENERGY STAR Door - Electric furnace	Electric	SF	N/A	Retrofit	0.17	0.17	0.28	0.99	0.17
8046	Shell	ENERGY STAR Door - Electric furnace	Electric	MH	N/A	Retrofit	0.17	0.17	0.28	0.99	0.17
8047	Shell	ENERGY STAR Door - Gas Heating	Electric	SF	N/A	Retrofit	0.02	0.02	0.03	0.64	0.03
8048	Shell	ENERGY STAR Door - Gas Heating	Electric	MH	N/A	Retrofit	0.02	0.02	0.03	0.64	0.03
9001	Water Heating	Pipe Wrap	Electric	SF	N/A	Retrofit	5.83	5.83	9.71	28.10	0.21
9002	Water Heating	Pipe Wrap	Electric	SF	N/A	NC	5.83	5.83	9.71	28.10	0.21
9003	Water Heating	Pipe Wrap	Electric	MH	N/A	Retrofit	5.83	5.83	9.71	28.10	0.21
9004	Water Heating	Pipe Wrap	Electric	MH	N/A	NC	5.83	5.83	9.71	28.10	0.21
9005	Water Heating	Bathroom Aerator 1.0 gpm	Electric	SF	N/A	Retrofit	32.32	32.32	39.16	25.71	1.39
9006	Water Heating	Bathroom Aerator 1.0 gpm	Electric	SF	N/A	NC	32.32	32.32	39.16	25.71	1.39
9007	Water Heating	Bathroom Aerator 1.0 gpm	Electric	MH	N/A	Retrofit	32.32	32.32	39.16	25.71	1.39
9008	Water Heating	Bathroom Aerator 1.0 gpm	Electric	MH	N/A	NC	32.32	32.32	39.16	25.71	1.39
9009	Water Heating	Kitchen Flip Aerator 1.5 gpm	Electric	SF	N/A	Retrofit	104.43	104.43	100.36	171.16	0.47
9010	Water Heating	Kitchen Flip Aerator 1.5 gpm	Electric	SF	N/A	NC	104.43	104.43	100.36	171.16	0.47
9011	Water Heating	Kitchen Flip Aerator 1.5 gpm	Electric	MH	N/A	Retrofit	104.43	104.43	100.36	171.16	0.47
9012	Water Heating	Kitchen Flip Aerator 1.5 gpm	Electric	MH	N/A	NC	104.43	104.43	100.36	171.16	0.47
9013	Water Heating	Low Flow Showerhead 1.5 gpm	Electric	SF	N/A	Retrofit	30.30	30.30	23.41	60.54	0.32
9014	Water Heating	Low Flow Showerhead 1.5 gpm	Electric	SF	N/A	NC	30.30	30.30	23.41	60.54	0.32
9015	Water Heating	Low Flow Showerhead 1.5 gpm	Electric	MH	N/A	Retrofit	30.30	30.30	23.41	60.54	0.32
9016	Water Heating	Low Flow Showerhead 1.5 gpm	Electric	MH	N/A	NC	30.30	30.30	23.41	60.54	0.32
9017	Water Heating	Thermostatic Restrictor Shower Valve	Electric	SF	N/A	Retrofit	2.38	2.38	1.62	5.60	0.23
9018	Water Heating	Thermostatic Restrictor Shower Valve	Electric	SF	N/A	NC	2.38	2.38	1.62	5.60	0.23
9019	Water Heating	Thermostatic Restrictor Shower Valve	Electric	MH	N/A	Retrofit	2.38	2.38	1.62	5.60	0.23
9020	Water Heating	Thermostatic Restrictor Shower Valve	Electric	MH	N/A	NC	2.38	2.38	1.62	5.60	0.23
9021	Water Heating	Heat Pump Water Heater (UEF 2.0)-electric resistance heat	Electric	SF	N/A	MO	1.61	1.61	2.68	4.08	0.40
9022	Water Heating	Heat Pump Water Heater (UEF 2.0)-electric resistance heat	Electric	SF	N/A	NC	1.61	1.61	2.68	4.08	0.40
9023	Water Heating	Heat Pump Water Heater (UEF 2.0)-electric resistance heat	Electric	MH	N/A	MO	1.48	1.48	2.46	3.79	0.39
9024	Water Heating	Heat Pump Water Heater (UEF 2.0)-electric resistance heat	Electric	MH	N/A	NC	1.48	1.48	2.46	3.79	0.39
9025	Water Heating	Heat Pump Water Heater (UEF 2.0)-heat pump heat	Electric	SF	N/A	MO	1.62	1.62	2.70	4.09	0.40
9026	Water Heating	Heat Pump Water Heater (UEF 2.0)-heat pump heat	Electric	SF	N/A	NC	1.62	1.62	2.70	4.09	0.40
9027	Water Heating	Heat Pump Water Heater (UEF 2.0)-heat pump heat	Electric	MH	N/A	MO	1.48	1.48	2.47	3.80	0.39
9028	Water Heating	Heat Pump Water Heater (UEF 2.0)-heat pump heat	Electric	MH	N/A	NC	1.48	1.48	2.47	3.80	0.39
9029	Water Heating	Heat Pump Water Heater (UEF 2.0)-gas heat	Electric	SF	N/A	MO	1.63	1.63	2.71	4.11	0.40
9030	Water Heating	Heat Pump Water Heater (UEF 2.0)-gas heat	Electric	SF	N/A	NC	1.63	1.63	2.71	4.11	0.40
9031	Water Heating	Heat Pump Water Heater (UEF 2.0)-gas heat	Electric	MH	N/A	MO	1.49	1.49	2.48	3.82	0.39
9032	Water Heating	Heat Pump Water Heater (UEF 2.0)-gas heat	Electric	MH	N/A	MO	1.49	1.49	2.48	3.82	0.39
9033	Water Heating	Heat Pump Water Heater (UEF 2.6)-electric resistance heat	Electric	SF	N/A	MO	1.64	1.64	2.74	4.15	0.40
9034	Water Heating	Heat Pump Water Heater (UEF 2.6)-electric resistance heat	Electric	SF	N/A	NC	1.64	1.64	2.74	4.15	0.40
9035	Water Heating	Heat Pump Water Heater (UEF 2.6)-electric resistance heat	Electric	MH	N/A	MO	1.51	1.51	2.51	3.85	0.39
9036	Water Heating	Heat Pump Water Heater (UEF 2.6)-electric resistance heat	Electric	MH	N/A	NC	1.51	1.51	2.51	3.85	0.39
9037	Water Heating	Heat Pump Water Heater (UEF 2.6)-heat pump heat	Electric	SF	N/A	MO	1.65	1.65	2.75	4.16	0.40
9038	Water Heating	Heat Pump Water Heater (UEF 2.6)-heat pump heat	Electric	SF	N/A	NC	1.65	1.65	2.75	4.16	0.40
9039	Water Heating	Heat Pump Water Heater (UEF 2.6)-heat pump heat	Electric	MH	N/A	MO	1.51	1.51	2.52	3.87	0.39
9040	Water Heating	Heat Pump Water Heater (UEF 2.6)-heat pump heat	Electric	MH	N/A	NC	1.51	1.51	2.52	3.87	0.39
9041	Water Heating	Heat Pump Water Heater (UEF 2.6)-gas heat	Electric	SF	N/A	MO	1.66	1.66	2.77	4.18	0.40
9042	Water Heating	Heat Pump Water Heater (UEF 2.6)-gas heat	Electric	SF	N/A	NC	1.66	1.66	2.77	4.18	0.40
9043	Water Heating	Heat Pump Water Heater (UEF 2.6)-gas heat	Electric	MH	N/A	MO	1.52	1.52	2.54	3.88	0.39
9044	Water Heating	Heat Pump Water Heater (UEF 2.6)-gas heat	Electric	MH	N/A	MO	1.52	1.52	2.54	3.88	0.39
9045	Water Heating	Water Heater Wrap	Electric	SF	N/A	Retrofit	3.95	3.95	6.58	3.43	1.15
9046	Water Heating	Water Heater Wrap	Electric	SF	N/A	NC	3.95	3.95	6.58	3.43	1.15
9047	Water Heating	Water Heater Wrap	Electric	MH	N/A	Retrofit	3.95	3.95	6.58	3.43	1.15
9048	Water Heating	Water Heater Wrap	Electric	MH	N/A	NC	3.95	3.95	6.58	3.43	1.15

Big Rivers — **Measure Benefit-Cost Ratios**

Measure #	End-Use	Measure Name	Measure Designation	Home Type	Income Type	Replacement Type	TRC BC Ratio	Societal	UCT	Participant	RIM
9049	Water Heating	Drain water Heat Recovery	Electric	SF	N/A	Retrofit	0.42	0.42	0.70	2.65	0.16
9050	Water Heating	Drain water Heat Recovery	Electric	SF	N/A	NC	0.42	0.42	0.70	2.65	0.16
9051	Water Heating	Drain water Heat Recovery	Electric	MH	N/A	Retrofit	0.42	0.42	0.70	2.65	0.16
9052	Water Heating	Drain water Heat Recovery	Electric	MH	N/A	NC	0.42	0.42	0.70	2.65	0.16
9053	Water Heating	Shower Timer	Electric	SF	N/A	Retrofit	1.64	1.64	1.99	2.01	0.77
9054	Water Heating	Shower Timer	Electric	SF	N/A	NC	1.64	1.64	1.99	2.01	0.77
9055	Water Heating	Shower Timer	Electric	MH	N/A	Retrofit	1.57	1.57	1.88	2.01	0.72
9056	Water Heating	Shower Timer	Electric	MH	N/A	NC	1.57	1.57	1.88	2.01	0.72
9057	Cross-Cutting	Multi-Family Homes Efficiency Kit	Electric	MF	N/A	Retrofit	1.10	1.10	1.83	3.74	0.29
9058	Cross-Cutting	Multi-Family Homes Efficiency Kit	Electric	MF	N/A	NC	1.10	1.10	1.83	3.74	0.29

APPENDIX B: NON-RESIDENTIAL MEASURE DETAIL

Big Rivers — **Measure Assumption Tab**

Measure #	Building Type	Measure Name	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW	RC EUL	EE EUL	Measure Cost	Incentive Amount	TRC
1	Assembly	Commercial Combination Oven (Electric)	MO	19,496.1	38.6%	7,532.5	1.8	0.8	12.0	12.0	$2,270.00	$1,362.00	2.4
2	Assembly	Commercial Electric Convection Oven	MO	10,863.7	19.0%	2,064.2	0.5	0.2	12.0	12.0	$960.00	$576.00	1.5
3	Assembly	Commercial Electric Griddle	MO	17,056.0	15.2%	2,596.0	0.6	0.3	12.0	12.0	$0.00	$0.00	0.0
4	Assembly	Commercial Electric Steam Cooker	MO	16,914.5	79.9%	13,506.7	3.3	1.4	12.0	12.0	$2,757.00	$1,654.20	3.5
5	Assembly	Dishwasher Low Temp Door (Energy Star)	MO	35,655.0	44.2%	15,765.8	3.9	1.7	16.0	16.0	$466.50	$279.90	30.0
6	Assembly	Dishwasher High Temp Door (Energy Star)	MO	38,282.0	16.4%	6,278.8	1.5	0.7	15.0	15.0	$1,550.00	$930.00	3.4
7	Assembly	Energy efficient electric fryer	MO	18,955.0	17.3%	3,274.0	0.8	0.3	12.0	12.0	$1,500.00	$900.00	1.6
8	Assembly	Insulated Holding Cabinets	MO	1,478.3	36.9%	545.3	0.1	0.1	12.0	12.0	$1,000.00	$600.00	0.4
9	Assembly	Compressed Air Leak Repair	RETRO	5.9	17.0%	1.0	0.0	0.0	3.0	3.0	$0.08	$0.05	2.2
10	Assembly	Retro-commissioning_Compressed Air Optimization	RETRO	4.8	21.0%	1.0	0.0	0.0	5.0	5.0	$0.22	$0.13	1.3
11	Assembly	Efficient Air Compressors (VSD)	MO	23,741.6	20.8%	4,935.1	0.6	0.6	13.0	13.0	$3,367.84	$2,020.70	0.9
12	Assembly	No Loss Condensate Drain	RETRO	476,153.6	0.4%	1,969.7	0.2	0.2	10.0	10.0	$244.00	$146.40	4.0
13	Assembly	Efficient Air Nozzles	MO	1,129.7	50.0%	564.9	0.1	0.1	15.0	15.0	$57.00	$34.20	6.8
14	Assembly	Air Conditioner - 17 IEER (5-20 Tons)	MO	757.3	14.1%	106.9	0.1	0.0	15.0	15.0	$153.28	$91.97	0.7
15	Assembly	Air Conditioner - 18 IEER (5-20 Tons)	MO	757.3	18.9%	143.0	0.1	0.0	15.0	15.0	$214.59	$128.75	0.7
16	Assembly	Air Conditioner - 21 IEER (5-20 Tons)	MO	757.3	30.5%	230.8	0.1	0.0	15.0	15.0	$398.52	$239.11	0.6
17	Assembly	Air Conditioner - 14.3 IEER (20+ Tons)	MO	850.5	9.1%	77.3	0.0	0.0	15.0	15.0	$71.00	$42.60	1.1
18	Assembly	Air Conditioner - 15 IEER (20+ Tons)	MO	850.5	13.3%	113.4	0.1	0.0	15.0	15.0	$109.23	$65.54	1.1
19	Assembly	Air Conditioner - 17 IEER (20+ Tons)	MO	850.5	23.5%	200.1	0.1	0.0	15.0	15.0	$218.46	$131.08	1.0
20	Assembly	Comprehensive Rooftop Unit Quality Maintenance (AC Tune-up)	RETRO	921.3	7.0%	64.5	0.0	0.0	3.0	3.0	$11.42	$6.85	1.5
21	Assembly	Air Side Economizer	RETRO	757.3	20.0%	151.5	0.1	0.0	10.0	10.0	$126.67	$76.00	0.9
22	Assembly	HVAC Occupancy Controls	RETRO	799.2	20.0%	159.8	0.1	0.0	15.0	15.0	$197.50	$118.50	0.8
23	Assembly	Air Conditioner - 16 SEER (<5 Tons)	MO	789.7	12.5%	98.7	0.0	0.0	15.0	15.0	$115.00	$69.00	0.9
24	Assembly	Air Conditioner - 18 SEER(<5 Tons)	MO	789.7	22.2%	175.5	0.1	0.0	15.0	15.0	$514.00	$308.40	0.4
25	Assembly	Air Conditioner - 21 SEER (<5 Tons)	MO	789.7	33.3%	263.2	0.1	0.0	15.0	15.0	$630.50	$378.30	0.4
26	Assembly	Smart Thermostat	RETRO	4,532.4	14.2%	641.8	0.3	0.0	11.0	11.0	$175.00	$105.00	3.0
27	Assembly	PTAC - 7,000 to 15,000 Btuh	MO	1,019.0	14.6%	148.4	0.1	0.0	8.0	8.0	$84.00	$50.40	1.1
28	Assembly	Air Cooled Chiller	MO	807.0	9.0%	72.7	0.0	0.0	23.0	23.0	$126.00	$75.60	0.7
29	Assembly	Water Cooled Chiller	MO	405.4	22.7%	92.1	0.0	0.0	23.0	23.0	$61.00	$36.60	1.9
30	Assembly	Window Film	RETRO	6,363.6	4.4%	280.0	0.1	0.0	10.0	10.0	$153.81	$92.29	1.4
31	Assembly	Triple Pane Windows	MO	6,363.6	6.0%	381.8	0.2	0.0	25.0	25.0	$700.00	$420.00	0.7
32	Assembly	Energy Recovery Ventilator	RETRO	850.5	0.0%	0.0	0.0	0.0	15.0	15.0	$1,500.00	$900.00	0.0
33	Assembly	Heat Pump - 16 SEER (<5 Tons)	MO	2,492.3	6.9%	172.7	0.0	0.0	15.0	15.0	$135.00	$81.00	1.2
34	Assembly	Heat Pump - 18 SEER(<5 Tons)	MO	2,492.3	13.4%	333.5	0.1	0.1	15.0	15.0	$445.76	$267.46	0.7
35	Assembly	Heat Pump - 21 SEER(<5 Tons)	MO	2,492.3	18.8%	467.6	0.1	0.1	15.0	15.0	$520.06	$312.04	0.8
36	Assembly	Heat Pump - 15.0 IEER COP 3.6 (65,000-134,000 Btu/hr)	MO	2,732.2	6.1%	165.9	0.0	0.0	15.0	15.0	$100.00	$60.00	1.5
37	Assembly	Heat Pump - 16.0 IEER COP 3.8 (65,000-134,000 Btu/hr)	MO	2,732.2	11.3%	308.3	0.0	0.1	15.0	15.0	$171.08	$102.65	1.7
38	Assembly	Heat Pump - 14.5 IEER COP 3.5 (135,000-239,000 Btu/hr)	MO	2,826.7	6.5%	182.8	0.0	0.0	15.0	15.0	$100.00	$60.00	1.7
39	Assembly	Heat Pump - 15.5 IEER COP 3.7 (135,000-239,000 Btu/hr)	MO	2,826.7	11.8%	333.7	0.1	0.1	15.0	15.0	$158.10	$94.86	1.9
40	Assembly	Heat Pump - 12 IEER 3.4 COP (>239,000 Btu/hr)	MO	2,951.3	6.3%	186.5	0.0	0.0	15.0	15.0	$100.00	$60.00	1.7
41	Assembly	Heat Pump - 13 IEER 3.6 COP (>239,000 Btu/hr)	MO	2,951.3	12.3%	361.7	0.1	0.1	15.0	15.0	$201.80	$121.08	1.6
42	Assembly	Geothermal HP - 17 EER < 135kbtu	MO	2,829.0	43.8%	1,239.5	0.2	0.3	25.0	25.0	$4,361.00	$2,616.60	0.3
43	Assembly	Geothermal HP - 19 EER < 135kbtu	MO	2,829.0	47.1%	1,333.0	0.2	0.3	25.0	25.0	$4,361.00	$2,616.60	0.3
44	Assembly	PTHP - 7,000 to 15,000 Btuh	MO	1,625.3	16.7%	270.9	0.0	0.1	15.0	15.0	$84.00	$50.40	3.0
45	Assembly	Heat Pump Water Heater	MO	10,590.6	73.3%	7,766.4	1.1	1.2	15.0	15.0	$1,797.00	$1,078.20	3.3
46	Assembly	Low Flow Faucet Aerator	RETRO	394.9	32.4%	127.8	0.0	0.0	10.0	10.0	$8.00	$4.80	8.9
47	Assembly	Pre-Rinse Spray Valves - DI	RETRO	18,058.7	54.2%	9,788.8	1.3	1.5	5.0	5.0	$54.00	$32.40	55.6
48	Assembly	Ozone Commercial Laundry	RETRO	2,984.0	25.0%	746.0	0.1	0.1	10.0	10.0	$20,309.70	$12,185.82	0.0
49	Assembly	Ext LED Replacing 100W MH (24/7)	RETRO	995.8	75.8%	754.8	0.0	0.1	10.0	10.0	$97.00	$58.20	2.8
50	Assembly	Ext LED Replacing 175W MH (24/7)	RETRO	1,743.6	71.0%	1,238.6	0.0	0.1	10.0	10.0	$123.81	$74.29	3.6

Big Rivers | **Measure Assumption Tab**

Measure #	Building Type	Measure Name	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW	RC EUL	EE EUL	Measure Cost	Incentive Amount	TRC
51	Assembly	Ext LED Replacing 250W MH (24/7)	RETRO	2,490.4	66.6%	1,658.5	0.0	0.2	10.0	10.0	$134.35	$80.61	4.4
52	Assembly	Ext LED Replacing 400W MH (24/7)	RETRO	3,984.1	64.5%	2,570.2	0.0	0.3	10.0	10.0	$196.16	$117.70	4.7
53	Assembly	Ext LED Replacing 1000W MH (24/7)	RETRO	9,467.3	70.4%	6,665.7	0.0	0.8	10.0	10.0	$319.31	$191.59	7.5
54	Assembly	Ext LED Replacing 100W MH (D2D)	RETRO	488.8	75.8%	370.5	0.0	0.0	10.0	10.0	$97.00	$58.20	1.4
55	Assembly	Ext LED Replacing 175W MH (D2D)	RETRO	855.9	71.0%	608.0	0.0	0.1	10.0	10.0	$123.81	$74.29	1.8
56	Assembly	Ext LED Replacing 250W MH (D2D)	RETRO	1,222.5	66.6%	814.1	0.0	0.1	10.0	10.0	$134.35	$80.61	2.2
57	Assembly	Ext LED Replacing 400W MH (D2D)	RETRO	1,955.7	64.5%	1,261.6	0.0	0.1	10.0	10.0	$196.16	$117.70	2.3
58	Assembly	Ext LED Replacing 1000W MH (D2D)	RETRO	4,647.2	70.4%	3,272.0	0.0	0.4	10.0	10.0	$319.31	$191.59	3.7
59	Assembly	LED Interior Direction (Track lighting / Wall-Wash Fixture)	RETRO	126.2	73.8%	93.1	0.0	0.0	15.0	15.0	$59.00	$35.40	1.1
60	Assembly	LED Linear Replacement Lamps (Replacing T8)	RETRO	91.2	51.4%	46.9	0.0	0.0	10.0	10.0	$15.00	$9.00	1.6
61	Assembly	LED Troffers (Replacing 1-Lamp T8)	RETRO	94.1	34.0%	32.0	0.0	0.0	15.0	15.0	$22.00	$13.20	1.0
62	Assembly	LED Troffers (Replacing 2-Lamp T8)	RETRO	184.3	51.4%	94.7	0.0	0.0	15.0	15.0	$61.00	$36.60	1.1
63	Assembly	LED Troffers (Replacing 3-Lamp T8)	RETRO	273.2	54.0%	147.6	0.0	0.0	15.0	15.0	$76.00	$45.60	1.4
64	Assembly	LED Troffers (Replacing 4-Lamp T8)	RETRO	364.0	54.3%	197.5	0.0	0.0	15.0	15.0	$104.00	$62.40	1.4
65	Assembly	LED Linear Ambient Fixture (<6000 lumens, replacing T8)	RETRO	183.8	50.3%	92.5	0.0	0.0	15.0	15.0	$46.67	$28.00	1.4
66	Assembly	LED Linear Ambient Fixture (>6000 lumens, replacing T5HO)	RETRO	484.9	53.2%	257.8	0.0	0.0	15.0	15.0	$152.00	$91.20	1.2
67	Assembly	LED Low-Bay Fixture	RETRO	507.6	67.0%	340.1	0.0	0.0	15.0	15.0	$42.88	$25.73	5.6
68	Assembly	LED High-Bay Fixture (Replacing T8 High Bay)	RETRO	950.5	57.0%	542.0	0.1	0.1	15.0	15.0	$48.07	$28.84	8.0
69	Assembly	LED High-Bay Fixture (Replacing Metal Halide)	RETRO	3,814.9	72.3%	2,758.4	0.4	0.4	15.0	15.0	$187.94	$112.76	10.4
70	Assembly	Fluorescent Delamping	RETRO	81.1	100.0%	81.1	0.0	0.0	11.0	11.0	$18.50	$11.10	2.5
71	Assembly	Lighting Occupancy Sensor	RETRO	421.6	30.0%	126.5	0.0	0.0	15.0	15.0	$65.40	$39.24	1.4
72	Assembly	Lighting Daylight Sensor	RETRO	539.9	28.0%	151.2	0.0	0.0	15.0	15.0	$57.50	$34.50	1.9
73	Assembly	Dual Occupancy / Daylight Sensor	RETRO	240.9	38.0%	91.5	0.0	0.0	15.0	15.0	$75.00	$45.00	0.9
74	Assembly	Luminaire-Level Lighting Controls	RETRO	240.9	61.0%	146.9	0.0	0.0	15.0	15.0	$56.00	$33.60	1.9
75	Assembly	Networked Lighting Control	RETRO	2.0	35.0%	0.7	0.0	0.0	15.0	15.0	$0.41	$0.24	1.2
76	Assembly	LED Exit Sign	RETRO	66.3	71.4%	47.4	0.0	0.0	5.0	5.0	$32.50	$19.50	0.4
77	Assembly	Non-Refrigerated Vending Machine Controls	RETRO	385.4	61.4%	236.8	0.0	0.0	5.0	5.0	$233.00	$139.80	0.3
78	Assembly	Kitchen Exhaust Hood Demand Ventilation Control System	MO	0.0	0.0%	0.0	0.0	0.0	20.0	20.0	$1.73	$1.04	0.0
79	Assembly	High Efficiency Hand Dryers	MO	2,092.6	83.0%	1,737.2	0.2	0.2	10.0	10.0	$483.00	$289.80	1.8
80	Assembly	ENERGY STAR Uninterrupted Power Supply	RETRO	3,125.1	3.7%	114.4	0.0	0.0	15.0	15.0	$59.00	$35.40	1.3
81	Assembly	Miscellaneous Custom	RETRO	6.7	15.0%	1.0	0.0	0.0	10.0	10.0	$0.40	$0.24	1.2
82	Assembly	Pump and Fan Variable Frequency Drive Controls (Pumps)	MO	1,502.7	27.7%	416.7	0.0	0.1	15.0	15.0	$198.32	$118.99	1.4
83	Assembly	Power Drive Systems	RETRO	4.3	23.0%	1.0	0.0	0.0	15.0	15.0	$0.13	$0.08	5.3
84	Assembly	Switch Reluctance Motors	MO	33,405.7	30.6%	10,222.1	0.0	2.3	15.0	15.0	$527.50	$316.50	13.2
85	Assembly	Energy Star Printer/Copier/Fax	MO	418.0	26.3%	110.0	0.0	0.0	6.0	6.0	$0.00	$0.00	0.0
86	Assembly	Advanced Power Strip – Teri 1 Commercial Use	RETRO	188.2	57.7%	108.6	0.0	0.0	7.0	7.0	$10.00	$6.00	4.0
87	Assembly	Smart Socket	RETRO	79.9	60.6%	48.4	0.0	0.0	7.0	7.0	$9.00	$5.40	2.0
88	Assembly	Energy Star Server	MO	2,166.7	30.0%	650.0	0.1	0.1	9.0	9.0	$300.95	$180.57	1.0
89	Assembly	Server Virtualization	RETRO	2,166.7	13.9%	301.1	0.0	0.0	9.0	9.0	$26.97	$16.18	5.1
90	Assembly	Electrically Commutated Plug Fans in data centers	RETRO	86,783.0	18.2%	15,778.0	2.0	1.9	15.0	15.0	$480.00	$288.00	22.5
91	Assembly	Computer Room Air Conditioner Economizer	RETRO	764.0	46.9%	358.0	0.0	0.0	15.0	15.0	$82.00	$49.20	3.0
92	Assembly	High Efficiency CRAC unit	MO	8,940.1	25.3%	2,264.8	0.3	0.3	20.0	20.0	$750.00	$450.00	2.6
93	Assembly	Data Center Hot/Cold Aisle Configuration	RETRO	13.3	7.5%	1.0	0.0	0.0	10.0	10.0	$0.23	$0.14	2.2
94	Assembly	Strip Curtains	RETRO	0.0	0.0%	0.0	0.0	0.0	4.0	4.0	$10.22	$6.13	0.0
95	Assembly	Floating Head Pressure Controls	RETRO	1,228.0	25.0%	307.0	0.0	0.0	15.0	15.0	$431.00	$258.60	0.5
96	Assembly	Electronically Commutated (EC) Walk-In Evaporator Fan Motor	RETRO	2,883.6	55.0%	1,586.0	0.2	0.2	15.0	15.0	$305.00	$183.00	3.6
97	Assembly	Evaporator Fan Motor Controls	RETRO	1,297.6	22.6%	293.0	0.0	0.0	13.0	13.0	$161.75	$97.05	1.1
98	Assembly	Variable Speed Condenser Fan	RETRO	3,157.9	47.5%	1,500.0	0.2	0.2	15.0	15.0	$1,170.00	$702.00	0.9
99	Assembly	Door Heater Controls for Cooler	RETRO	578.6	41.5%	240.1	0.0	0.0	10.0	10.0	$79.50	$47.70	1.5
100	Assembly	Automated Door Closer for Refrigerator	RETRO	1,259,892.8	0.2%	2,398.7	0.3	0.3	8.0	8.0	$502.00	$301.20	2.0

Big Rivers — **Measure Assumption Tab**

Measure #	Building Type	Measure Name	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW	RC EUL	EE EUL	Measure Cost	Incentive Amount	TRC
101	Assembly	Aerofoils for Open Display Cases	RETRO	45,880.0	10.0%	4,588.0	0.6	0.5	10.0	10.0	$311.54	$186.92	7.4
102	Assembly	Display Case Door Retrofit, Medium Temp	RETRO	1,558.3	50.0%	779.1	0.1	0.1	15.0	15.0	$390.00	$234.00	1.4
103	Assembly	Electronically Commutated (EC) Reach-In Evaporator Fan Motor	RETRO	2,883.6	55.0%	1,586.0	0.2	0.2	15.0	15.0	$305.00	$183.00	3.6
104	Assembly	Q-Sync Motor for Walk-In and Reach-in Evaporator Fan Motor	RETRO	2,090.6	24.1%	504.6	0.1	0.1	10.0	10.0	$96.00	$57.60	2.7
105	Assembly	Night Covers for Coolers	RETRO	1,510.5	9.0%	136.0	0.0	0.0	5.0	5.0	$42.00	$25.20	0.9
106	Assembly	Door Heater Controls for Freezer	RETRO	2,016.2	32.5%	655.3	0.1	0.1	10.0	10.0	$79.50	$47.70	4.2
107	Assembly	Automated Door Closer for Freezer	RETRO	1,259,892.8	0.6%	6,948.8	1.0	0.8	8.0	8.0	$502.00	$301.20	5.8
108	Assembly	Night Covers for Freezers	RETRO	2,349.3	9.0%	211.3	0.0	0.0	5.0	5.0	$42.00	$25.20	1.4
109	Assembly	Refrigeration - Custom	RETRO	6.7	15.0%	1.0	0.0	0.0	10.0	10.0	$0.40	$0.24	1.3
110	Assembly	Retro-commissioning_Refrigerator Optimization	RETRO	4.8	21.0%	1.0	0.0	0.0	5.0	5.0	$0.22	$0.13	1.3
111	Assembly	ESTAR Refrigerated Vending Machine	MO	1,277.5	12.0%	153.3	0.0	0.0	14.0	14.0	$500.00	$300.00	0.2
112	Assembly	Refrigerated Vending Machine Controls	RETRO	1,662.9	23.5%	390.1	0.1	0.0	5.0	5.0	$245.00	$147.00	0.4
113	Assembly	Commercial Ice Marker	MO	5,550.9	7.9%	440.3	0.1	0.0	9.0	9.0	$222.00	$133.20	0.9
114	Assembly	LED Refrigerated Display Case Lighting Average 6W/LF	MO	114.6	73.7%	84.5	0.0	0.0	9.0	9.0	$11.00	$6.60	3.5
115	Assembly	Pump and Fan Variable Frequency Drive Controls (Fans)	RETRO	7,654.7	59.0%	4,515.7	0.8	0.7	15.0	15.0	$2,250.00	$1,350.00	1.6
116	Assembly	Cogged V-Belt (Synchronous)	RETRO	17,237.2	3.1%	534.4	0.1	0.1	15.0	15.0	$381.00	$228.60	1.0
117	Assembly	HVAC - Energy Management System	RETRO	12.5	8.0%	1.0	0.0	0.0	15.0	15.0	$0.40	$0.24	1.9
118	Assembly	GREM Controls	RETRO	0.0	0.0%	0.0	0.0	0.0	15.0	15.0	$0.00	$0.00	0.0
119	Assembly	Demand Control Ventilation	RETRO	1,920.0	20.0%	384.0	0.1	0.0	10.0	10.0	$235.60	$141.36	0.9
120	Assembly	High Efficiency DOAS	RETRO	5.2	35.7%	1.9	0.0	0.0	15.0	15.0	$15.22	$9.13	0.1
121	Assembly	Advanced Rooftop Controls	RETRO	0.0	0.0%	0.0	0.0	0.0	10.0	10.0	$341.21	$204.72	0.0
122	Assembly	Retro-commissioning_Bld Optimization	RETRO	12.5	8.0%	1.0	0.0	0.0	15.0	15.0	$0.12	$0.07	6.3
123	Assembly	Commercial Weatherstripping	RETRO	222.3	2.0%	4.4	0.0	0.0	10.0	10.0	$8.00	$4.80	0.3
124	Assembly	WholeBlg - Com RET	RETRO	6.7	15.0%	1.0	0.0	0.0	15.0	15.0	$0.40	$0.24	1.9
125	Assembly	Strategic Energy Management	RETRO	0.0	0.0%	0.0	0.0	0.0	5.0	5.0	$0.27	$0.16	0.7
126	Assembly	Power Distribution Equipment Upgrades (Transformers)	RETRO	990.2	0.6%	5.5	0.0	0.0	30.0	30.0	$6.27	$3.76	0.8
127	Assembly	WholeBlg - Com NC	NC	4.0	25.0%	1.0	0.0	0.0	15.0	15.0	$0.40	$0.24	1.9
128	Education	Commercial Combination Oven (Electric)	MO	19,496.1	38.6%	7,532.5	0.1	0.3	12.0	12.0	$2,270.00	$1,362.00	1.1
129	Education	Commercial Electric Convection Oven	MO	10,863.7	19.0%	2,064.2	0.0	0.1	12.0	12.0	$960.00	$576.00	0.7
130	Education	Commercial Electric Griddle	MO	17,056.0	15.2%	2,596.0	0.0	0.1	12.0	12.0	$0.00	$0.00	0.0
131	Education	Commercial Electric Steam Cooker	MO	16,914.5	79.9%	13,506.7	0.1	0.5	12.0	12.0	$2,757.00	$1,654.20	1.6
132	Education	Dishwasher Low Temp Door (Energy Star)	MO	35,655.0	44.2%	15,765.8	0.2	0.6	16.0	16.0	$466.50	$279.90	13.2
133	Education	Dishwasher High Temp Door (Energy Star)	MO	38,282.0	16.4%	6,278.8	0.1	0.2	15.0	15.0	$1,550.00	$930.00	1.5
134	Education	Energy efficient electric fryer	MO	18,955.0	17.3%	3,274.0	0.0	0.1	12.0	12.0	$1,500.00	$900.00	0.7
135	Education	Insulated Holding Cabinets	MO	1,478.3	36.9%	545.3	0.0	0.0	12.0	12.0	$1,000.00	$600.00	0.2
136	Education	Compressed Air Leak Repair	RETRO	5.9	17.0%	1.0	0.0	0.0	3.0	3.0	$0.08	$0.05	2.0
137	Education	Retro-commissioning_Compressed Air Optimization	RETRO	4.8	21.0%	1.0	0.0	0.0	5.0	5.0	$0.22	$0.13	1.2
138	Education	Efficient Air Compressors (VSD)	MO	23,741.6	20.8%	4,935.1	0.5	0.6	13.0	13.0	$3,367.84	$2,020.70	0.8
139	Education	No Loss Condensate Drain	RETRO	476,153.6	0.4%	1,969.7	0.2	0.2	10.0	10.0	$244.00	$146.40	3.7
140	Education	Efficient Air Nozzles	MO	1,129.7	50.0%	564.9	0.1	0.1	15.0	15.0	$57.00	$34.20	6.2
141	Education	Air Conditioner - 17 IEER (5-20 Tons)	MO	546.3	14.1%	77.1	0.0	0.0	15.0	15.0	$153.28	$91.97	0.6
142	Education	Air Conditioner - 18 IEER (5-20 Tons)	MO	546.3	18.9%	103.2	0.1	0.0	15.0	15.0	$214.59	$128.75	0.5
143	Education	Air Conditioner - 21 IEER (5-20 Tons)	MO	546.3	30.5%	166.5	0.1	0.0	15.0	15.0	$398.52	$239.11	0.5
144	Education	Air Conditioner - 14.3 IEER (20+ Tons)	MO	613.6	9.1%	55.8	0.0	0.0	15.0	15.0	$71.00	$42.60	0.9
145	Education	Air Conditioner - 15 IEER (20+ Tons)	MO	613.6	13.3%	81.8	0.0	0.0	15.0	15.0	$109.23	$65.54	0.8
146	Education	Air Conditioner - 17 IEER (20+ Tons)	MO	613.6	23.5%	144.4	0.1	0.0	15.0	15.0	$218.46	$131.08	0.7
147	Education	Comprehensive Rooftop Unit Quality Maintenance (AC Tune-up)	RETRO	664.7	7.0%	46.5	0.0	0.0	3.0	3.0	$11.42	$6.85	1.1
148	Education	Air Side Economizer	RETRO	546.3	20.0%	109.3	0.1	0.0	10.0	10.0	$126.67	$76.00	0.7
149	Education	HVAC Occupancy Controls	RETRO	576.5	20.0%	115.3	0.1	0.0	15.0	15.0	$197.50	$118.50	0.6
150	Education	Air Conditioner - 16 SEER (<5 Tons)	MO	569.7	12.5%	71.2	0.0	0.0	15.0	15.0	$115.00	$69.00	0.7

Big Rivers | **Measure Assumption Tab**

Measure #	Building Type	Measure Name	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW	RC EUL	EE EUL	Measure Cost	Incentive Amount	TRC
151	Education	Air Conditioner - 18 SEER(<5 Tons)	MO	569.7	22.2%	126.6	0.1	0.0	15.0	15.0	$514.00	$308.40	0.3
152	Education	Air Conditioner - 21 SEER (<5 Tons)	MO	569.7	33.3%	189.9	0.1	0.0	15.0	15.0	$630.50	$378.30	0.3
153	Education	Smart Thermostat	RETRO	3,269.9	14.2%	463.0	0.2	0.0	11.0	11.0	$175.00	$105.00	2.3
154	Education	PTAC - 7,000 to 15,000 Btuh	MO	735.2	14.6%	107.1	0.1	0.0	8.0	8.0	$84.00	$50.40	0.8
155	Education	Air Cooled Chiller	MO	582.2	9.0%	52.5	0.0	0.0	23.0	23.0	$126.00	$75.60	0.6
156	Education	Water Cooled Chiller	MO	292.5	22.7%	66.5	0.0	0.0	23.0	23.0	$61.00	$36.60	1.5
157	Education	Window Film	RETRO	6,363.6	4.4%	280.0	0.1	0.0	10.0	10.0	$153.81	$92.29	1.5
158	Education	Triple Pane Windows	MO	6,363.6	6.0%	381.8	0.2	0.0	25.0	25.0	$700.00	$420.00	0.7
159	Education	Energy Recovery Ventilator	RETRO	613.6	0.0%	0.0	0.0	0.0	15.0	15.0	$1,500.00	$900.00	0.0
160	Education	Heat Pump - 16 SEER (<5 Tons)	MO	1,754.8	7.0%	122.7	0.0	0.0	15.0	15.0	$135.00	$81.00	0.9
161	Education	Heat Pump - 18 SEER(<5 Tons)	MO	1,754.8	13.5%	236.6	0.0	0.1	15.0	15.0	$445.76	$267.46	0.5
162	Education	Heat Pump - 21 SEER(<5 Tons)	MO	1,754.8	18.9%	332.1	0.1	0.1	15.0	15.0	$520.06	$312.04	0.6
163	Education	Heat Pump - 15.0 IEER COP 3.6 (65,000-134,000 Btu/hr)	MO	1,921.9	6.1%	117.0	0.0	0.0	15.0	15.0	$100.00	$60.00	1.2
164	Education	Heat Pump - 16.0 IEER COP 3.8 (65,000-134,000 Btu/hr)	MO	1,921.9	11.3%	217.2	0.0	0.1	15.0	15.0	$171.08	$102.65	1.3
165	Education	Heat Pump - 14.5 IEER COP 3.5 (135,000-239,000 Btu/hr)	MO	1,988.6	6.5%	129.0	0.0	0.0	15.0	15.0	$100.00	$60.00	1.3
166	Education	Heat Pump - 15.5 IEER COP 3.7 (135,000-239,000 Btu/hr)	MO	1,988.6	11.8%	235.3	0.0	0.1	15.0	15.0	$158.10	$94.86	1.5
167	Education	Heat Pump - 12 IEER 3.4 COP (>239,000 Btu/hr)	MO	2,077.1	6.3%	131.9	0.0	0.0	15.0	15.0	$100.00	$60.00	1.3
168	Education	Heat Pump - 13 IEER 3.6 COP (>239,000 Btu/hr)	MO	2,077.1	12.3%	255.2	0.0	0.1	15.0	15.0	$201.80	$121.08	1.3
169	Education	Geothermal HP - 17 EER < 135kbtu	MO	1,990.2	43.5%	866.7	0.2	0.2	25.0	25.0	$4,361.00	$2,616.60	0.2
170	Education	Geothermal HP - 19 EER < 135kbtu	MO	1,990.2	46.9%	932.8	0.2	0.2	25.0	25.0	$4,361.00	$2,616.60	0.3
171	Education	PTHP - 7,000 to 15,000 Btuh	MO	3,982.4	16.7%	663.7	0.1	0.2	15.0	15.0	$84.00	$50.40	7.9
172	Education	Heat Pump Water Heater	MO	17,640.7	73.3%	12,936.5	1.3	2.1	15.0	15.0	$1,797.00	$1,078.20	5.2
173	Education	Low Flow Faucet Aerator	RETRO	473.9	32.4%	153.4	0.0	0.0	10.0	10.0	$8.00	$4.80	10.0
174	Education	Pre-Rinse Spray Valves - DI	RETRO	18,058.7	54.2%	9,788.8	1.0	1.6	5.0	5.0	$54.00	$32.40	52.5
175	Education	Ozone Commercial Laundry	MO	2,984.0	25.0%	746.0	0.1	0.1	10.0	10.0	$20,309.70	$12,185.82	0.0
176	Education	Ext LED Replacing 100W MH (24/7)	RETRO	995.8	75.8%	754.8	0.0	0.1	10.0	10.0	$97.00	$58.20	2.8
177	Education	Ext LED Replacing 175W MH (24/7)	RETRO	1,743.6	71.0%	1,238.6	0.0	0.1	10.0	10.0	$123.81	$74.29	3.6
178	Education	Ext LED Replacing 250W MH (24/7)	RETRO	2,490.4	66.6%	1,658.5	0.0	0.2	10.0	10.0	$134.35	$80.61	4.4
179	Education	Ext LED Replacing 400W MH (24/7)	RETRO	3,984.1	64.5%	2,570.2	0.0	0.3	10.0	10.0	$196.16	$117.70	4.7
180	Education	Ext LED Replacing 1000W MH (24/7)	RETRO	9,467.3	70.4%	6,665.7	0.0	0.8	10.0	10.0	$319.31	$191.59	7.5
181	Education	Ext LED Replacing 100W MH (D2D)	RETRO	488.8	75.8%	370.5	0.0	0.0	10.0	10.0	$97.00	$58.20	1.4
182	Education	Ext LED Replacing 175W MH (D2D)	RETRO	855.9	71.0%	608.0	0.0	0.1	10.0	10.0	$123.81	$74.29	1.8
183	Education	Ext LED Replacing 250W MH (D2D)	RETRO	1,222.5	66.6%	814.1	0.0	0.1	10.0	10.0	$134.35	$80.61	2.2
184	Education	Ext LED Replacing 400W MH (D2D)	RETRO	1,955.7	64.5%	1,261.6	0.0	0.1	10.0	10.0	$196.16	$117.70	2.3
185	Education	Ext LED Replacing 1000W MH (D2D)	RETRO	4,647.2	70.4%	3,272.0	0.0	0.4	10.0	10.0	$319.31	$191.59	3.7
186	Education	LED Interior Direction (Track lighting / Wall-Wash Fixture)	RETRO	127.3	73.8%	93.9	0.0	0.0	15.0	15.0	$59.00	$35.40	1.0
187	Education	LED Linear Replacement Lamps (Replacing T8)	RETRO	91.9	51.4%	47.3	0.0	0.0	10.0	10.0	$15.00	$9.00	1.5
188	Education	LED Troffers (Replacing 1-Lamp T8)	RETRO	94.9	34.0%	32.3	0.0	0.0	15.0	15.0	$22.00	$13.20	0.9
189	Education	LED Troffers (Replacing 2-Lamp T8)	RETRO	185.8	51.4%	95.5	0.0	0.0	15.0	15.0	$61.00	$36.60	1.0
190	Education	LED Troffers (Replacing 3-Lamp T8)	RETRO	275.5	54.0%	148.9	0.0	0.0	15.0	15.0	$76.00	$45.60	1.3
191	Education	LED Troffers (Replacing 4-Lamp T8)	RETRO	367.1	54.3%	199.2	0.0	0.0	15.0	15.0	$104.00	$62.40	1.2
192	Education	LED Linear Ambient Fixture (<6000 lumens, replacing T8)	RETRO	185.4	50.3%	93.2	0.0	0.0	15.0	15.0	$46.67	$28.00	1.3
193	Education	LED Linear Ambient Fixture (>6000 lumens, replacing T5HO)	RETRO	489.0	53.2%	260.0	0.0	0.0	15.0	15.0	$152.00	$91.20	1.1
194	Education	LED Low-Bay Fixture	RETRO	511.8	67.0%	343.0	0.0	0.0	15.0	15.0	$42.88	$25.73	5.2
195	Education	LED High-Bay Fixture (Replacing T8 High Bay)	RETRO	958.5	57.0%	546.5	0.1	0.1	15.0	15.0	$48.07	$28.84	7.3
196	Education	LED High-Bay Fixture (Replacing Metal Halide)	RETRO	3,846.9	72.3%	2,781.5	0.3	0.3	15.0	15.0	$187.94	$112.76	9.5
197	Education	Fluorescent Delamping	RETRO	81.8	100.0%	81.8	0.0	0.0	11.0	11.0	$18.50	$11.10	2.2
198	Education	Lighting Occupancy Sensor	RETRO	425.1	30.0%	127.5	0.0	0.0	15.0	15.0	$65.40	$39.24	1.3
199	Education	Lighting Daylight Sensor	RETRO	544.4	28.0%	152.4	0.0	0.0	15.0	15.0	$57.50	$34.50	1.7
200	Education	Dual Occupancy / Daylight Sensor	RETRO	242.9	38.0%	92.3	0.0	0.0	15.0	15.0	$75.00	$45.00	0.8

Big Rivers | **Measure Assumption Tab**

Measure #	Building Type	Measure Name	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW	RC EUL	EE EUL	Measure Cost	Incentive Amount	TRC
201	Education	Luminaire-Level Lighting Controls	RETRO	242.9	61.0%	148.2	0.0	0.0	15.0	15.0	$56.00	$33.60	1.7
202	Education	Networked Lighting Control	RETRO	2.0	35.0%	0.7	0.0	0.0	15.0	15.0	$0.41	$0.25	1.1
203	Education	LED Exit Sign	RETRO	65.8	71.4%	47.0	0.0	0.0	5.0	5.0	$32.50	$19.50	0.4
204	Education	Non-Refrigerated Vending Machine Controls	RETRO	385.4	61.4%	236.8	0.0	0.0	5.0	5.0	$233.00	$139.80	0.3
205	Education	Kitchen Exhaust Hood Demand Ventilation Control System	MO	5.3	50.0%	2.6	0.0	0.0	20.0	20.0	$1.73	$1.04	1.2
206	Education	High Efficiency Hand Dryers	MO	2,092.6	83.0%	1,737.2	0.2	0.2	10.0	10.0	$483.00	$289.80	1.6
207	Education	ENERGY STAR Uninterrupted Power Supply	RETRO	3,125.1	3.7%	114.4	0.0	0.0	15.0	15.0	$59.00	$35.40	1.2
208	Education	Miscellaneous Custom	RETRO	6.7	15.0%	1.0	0.0	0.0	10.0	10.0	$0.40	$0.24	1.1
209	Education	Pump and Fan Variable Frequency Drive Controls (Pumps)	MO	2,296.0	27.7%	636.7	0.1	0.1	15.0	15.0	$198.32	$118.99	2.5
210	Education	Power Drive Systems	RETRO	4.3	23.0%	1.0	0.0	0.0	15.0	15.0	$0.13	$0.08	6.0
211	Education	Switch Reluctance Motors	MO	33,405.7	30.6%	10,222.1	1.2	1.8	15.0	15.0	$527.50	$316.50	15.1
212	Education	Energy Star Printer/Copier/Fax	MO	418.0	26.3%	110.0	0.0	0.0	6.0	6.0	$0.00	$0.00	0.0
213	Education	Advanced Power Strip – Teri 1 Commercial Use	RETRO	188.2	57.7%	108.6	0.0	0.0	7.0	7.0	$10.00	$6.00	3.7
214	Education	Smart Socket	RETRO	79.9	60.6%	48.4	0.0	0.0	7.0	7.0	$9.00	$5.40	1.8
215	Education	Energy Star Server	MO	2,166.7	30.0%	650.0	0.1	0.1	9.0	9.0	$300.95	$180.57	0.9
216	Education	Server Virtualization	RETRO	2,166.7	13.9%	301.1	0.0	0.0	9.0	9.0	$26.97	$16.18	4.7
217	Education	Electrically Commutated Plug Fans in data centers	RETRO	86,783.0	18.2%	15,778.0	1.5	1.8	15.0	15.0	$480.00	$288.00	20.7
218	Education	Computer Room Air Conditioner Economizer	RETRO	764.0	46.9%	358.0	0.0	0.0	15.0	15.0	$82.00	$49.20	2.7
219	Education	High Efficiency CRAC unit	MO	8,940.1	25.3%	2,264.8	0.2	0.3	20.0	20.0	$750.00	$450.00	2.3
220	Education	Data Center Hot/Cold Aisle Configuration	RETRO	13.3	7.5%	1.0	0.0	0.0	10.0	10.0	$0.23	$0.14	2.0
221	Education	Strip Curtains	RETRO	0.0	0.0%	0.0	0.0	0.0	4.0	4.0	$10.22	$6.13	0.0
222	Education	Floating Head Pressure Controls	RETRO	1,228.0	25.0%	307.0	0.0	0.0	15.0	15.0	$431.00	$258.60	0.5
223	Education	Electronically Commutated (EC) Walk-In Evaporator Fan Motor	RETRO	2,883.6	55.0%	1,586.0	0.2	0.2	15.0	15.0	$305.00	$183.00	3.6
224	Education	Evaporator Fan Motor Controls	RETRO	1,297.6	22.6%	293.0	0.0	0.0	13.0	13.0	$161.75	$97.05	1.1
225	Education	Variable Speed Condenser Fan	RETRO	3,157.9	47.5%	1,500.0	0.2	0.2	15.0	15.0	$1,170.00	$702.00	0.9
226	Education	Door Heater Controls for Cooler	RETRO	578.6	41.5%	240.1	0.0	0.0	10.0	10.0	$79.50	$47.70	1.5
227	Education	Automated Door Closer for Refrigerator	RETRO	1,259,892.8	0.2%	2,398.7	0.3	0.3	8.0	8.0	$502.00	$301.20	2.0
228	Education	Aerofoils for Open Display Cases	RETRO	45,880.0	10.0%	4,588.0	0.7	0.5	10.0	10.0	$311.54	$186.92	7.5
229	Education	Display Case Door Retrofit, Medium Temp	RETRO	1,558.3	50.0%	779.1	0.1	0.1	15.0	15.0	$390.00	$234.00	1.4
230	Education	Electronically Commutated (EC) Reach-In Evaporator Fan Motor	RETRO	2,883.6	55.0%	1,586.0	0.2	0.2	15.0	15.0	$305.00	$183.00	3.6
231	Education	Q-Sync Motor for Walk-In and Reach-in Evaporator Fan Motor	RETRO	2,090.6	24.1%	504.6	0.1	0.1	10.0	10.0	$96.00	$57.60	2.7
232	Education	Night Covers for Coolers	RETRO	1,510.5	9.0%	136.0	0.0	0.0	5.0	5.0	$42.00	$25.20	0.9
233	Education	Door Heater Controls for Freezer	RETRO	2,016.2	32.5%	655.3	0.1	0.1	10.0	10.0	$79.50	$47.70	4.2
234	Education	Automated Door Closer for Freezer	RETRO	1,259,892.8	0.6%	6,948.8	1.0	0.8	8.0	8.0	$502.00	$301.20	5.8
235	Education	Night Covers for Freezers	RETRO	2,349.3	9.0%	211.3	0.0	0.0	5.0	5.0	$42.00	$25.20	1.4
236	Education	Refrigeration - Custom	RETRO	6.7	15.0%	1.0	0.0	0.0	10.0	10.0	$0.40	$0.24	1.3
237	Education	Retro-commissioning_Refrigerator Optimization	RETRO	4.8	21.0%	1.0	0.0	0.0	5.0	5.0	$0.22	$0.13	1.3
238	Education	ESTAR Refrigerated Vending Machine	MO	1,277.5	12.0%	153.3	0.0	0.0	14.0	14.0	$500.00	$300.00	0.2
239	Education	Refrigerated Vending Machine Controls	RETRO	1,662.9	23.5%	390.1	0.1	0.0	5.0	5.0	$245.00	$147.00	0.4
240	Education	Commercial Ice Marker	MO	5,550.9	7.9%	440.3	0.1	0.0	9.0	9.0	$222.00	$133.20	0.9
241	Education	LED Refrigerated Display Case Lighting Average 6W/LF	MO	114.6	73.7%	84.5	0.0	0.0	9.0	9.0	$11.00	$6.60	3.6
242	Education	Pump and Fan Variable Frequency Drive Controls (Fans)	RETRO	7,654.7	59.0%	4,515.7	0.8	0.7	15.0	15.0	$2,250.00	$1,350.00	1.7
243	Education	Cogged V-Belt (Synchronous)	RETRO	17,237.2	3.1%	534.4	0.1	0.1	15.0	15.0	$381.00	$228.60	1.1
244	Education	HVAC - Energy Management System	RETRO	12.5	8.0%	1.0	0.0	0.0	15.0	15.0	$0.40	$0.24	2.0
245	Education	GREM Controls	RETRO	0.0	0.0%	0.0	0.0	0.0	15.0	15.0	$0.00	$0.00	0.0
246	Education	Demand Control Ventilation	RETRO	1,920.0	20.0%	384.0	0.1	0.1	10.0	10.0	$235.60	$141.36	1.0
247	Education	High Efficiency DOAS	RETRO	5.2	35.7%	1.9	0.0	0.0	15.0	15.0	$15.22	$9.13	0.1
248	Education	Advanced Rooftop Controls	RETRO	683.6	60.6%	414.5	0.1	0.1	10.0	10.0	$341.21	$204.72	0.7
249	Education	Retro-commissioning_Bld Optimization	RETRO	12.5	8.0%	1.0	0.0	0.0	15.0	15.0	$0.12	$0.07	6.7
250	Education	Commercial Weatherstripping	RETRO	222.3	2.0%	4.4	0.0	0.0	10.0	10.0	$8.00	$4.80	0.3

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Measure #	Building Type	Measure Name	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW	RC EUL	EE EUL	Measure Cost	Incentive Amount	TRC
251	Education	WholeBlg - Com RET	RETRO	6.7	15.0%	1.0	0.0	0.0	15.0	15.0	$0.40	$0.24	2.0
252	Education	Strategic Energy Management	RETRO	33.3	3.0%	1.0	0.0	0.0	5.0	5.0	$0.27	$0.16	1.2
253	Education	Power Distribution Equipment Upgrades (Transformers)	RETRO	990.2	0.6%	5.5	0.0	0.0	30.0	30.0	$6.27	$3.76	0.9
254	Education	WholeBlg - Com NC	NC	4.0	25.0%	1.0	0.0	0.0	15.0	15.0	$0.40	$0.24	2.0
255	Food Sales	Commercial Combination Oven (Electric)	MO	19,496.1	38.6%	7,532.5	1.5	1.0	12.0	12.0	$2,270.00	$1,362.00	2.3
256	Food Sales	Commercial Electric Convection Oven	MO	10,863.7	19.0%	2,064.2	0.4	0.3	12.0	12.0	$960.00	$576.00	1.5
257	Food Sales	Commercial Electric Griddle	MO	17,056.0	15.2%	2,596.0	0.5	0.3	12.0	12.0	$0.00	$0.00	0.0
258	Food Sales	Commercial Electric Steam Cooker	MO	16,914.5	79.9%	13,506.7	2.7	1.7	12.0	12.0	$2,757.00	$1,654.20	3.4
259	Food Sales	Dishwasher Low Temp Door (Energy Star)	MO	35,655.0	44.2%	15,765.8	3.2	2.0	16.0	16.0	$466.50	$279.90	29.0
260	Food Sales	Dishwasher High Temp Door (Energy Star)	MO	38,282.0	16.4%	6,278.8	1.3	0.8	15.0	15.0	$1,550.00	$930.00	3.3
261	Food Sales	Energy efficient electric fryer	MO	18,955.0	17.3%	3,274.0	0.7	0.4	12.0	12.0	$1,500.00	$900.00	1.5
262	Food Sales	Insulated Holding Cabinets	MO	1,478.3	36.9%	545.3	0.1	0.1	12.0	12.0	$1,000.00	$600.00	0.4
263	Food Sales	Compressed Air Leak Repair	RETRO	5.9	17.0%	1.0	0.0	0.0	3.0	3.0	$0.08	$0.05	2.3
264	Food Sales	Retro-commissioning_Compressed Air Optimization	RETRO	4.8	21.0%	1.0	0.0	0.0	5.0	5.0	$0.22	$0.13	1.3
265	Food Sales	Efficient Air Compressors (VSD)	MO	23,741.6	20.8%	4,935.1	0.8	0.6	13.0	13.0	$3,367.84	$2,020.70	0.9
266	Food Sales	No Loss Condensate Drain	RETRO	476,153.6	0.4%	1,969.7	0.3	0.2	10.0	10.0	$244.00	$146.40	4.2
267	Food Sales	Efficient Air Nozzles	MO	1,129.7	50.0%	564.9	0.1	0.1	15.0	15.0	$57.00	$34.20	7.2
268	Food Sales	Air Conditioner - 17 IEER (5-20 Tons)	MO	930.2	14.1%	131.3	0.1	0.0	15.0	15.0	$153.28	$91.97	1.1
269	Food Sales	Air Conditioner - 18 IEER (5-20 Tons)	MO	930.2	18.9%	175.7	0.1	0.0	15.0	15.0	$214.59	$128.75	1.1
270	Food Sales	Air Conditioner - 21 IEER (5-20 Tons)	MO	930.2	30.5%	283.5	0.2	0.0	15.0	15.0	$398.52	$239.11	0.9
271	Food Sales	Air Conditioner - 14.3 IEER (20+ Tons)	MO	1,044.7	9.1%	95.0	0.1	0.0	15.0	15.0	$71.00	$42.60	1.7
272	Food Sales	Air Conditioner - 15 IEER (20+ Tons)	MO	1,044.7	13.3%	139.3	0.1	0.0	15.0	15.0	$109.23	$65.54	1.6
273	Food Sales	Air Conditioner - 17 IEER (20+ Tons)	MO	1,044.7	23.5%	245.8	0.2	0.0	15.0	15.0	$218.46	$131.08	1.4
274	Food Sales	Comprehensive Rooftop Unit Quality Maintenance (AC Tune-up)	RETRO	1,131.8	7.0%	79.3	0.1	0.0	3.0	3.0	$11.42	$6.85	2.2
275	Food Sales	Air Side Economizer	RETRO	930.2	20.0%	186.0	0.1	0.0	10.0	10.0	$126.67	$76.00	1.4
276	Food Sales	HVAC Occupancy Controls	RETRO	981.7	20.0%	196.3	0.1	0.0	15.0	15.0	$197.50	$118.50	1.3
277	Food Sales	Air Conditioner - 16 SEER (<5 Tons)	MO	970.1	12.5%	121.3	0.1	0.0	15.0	15.0	$115.00	$69.00	1.4
278	Food Sales	Air Conditioner - 18 SEER(<5 Tons)	MO	970.1	22.2%	215.6	0.1	0.0	15.0	15.0	$514.00	$308.40	0.5
279	Food Sales	Air Conditioner - 21 SEER (<5 Tons)	MO	970.1	33.3%	323.4	0.2	0.0	15.0	15.0	$630.50	$378.30	0.7
280	Food Sales	Smart Thermostat	RETRO	5,567.5	14.2%	788.4	0.5	0.0	11.0	11.0	$175.00	$105.00	4.5
281	Food Sales	PTAC - 7,000 to 15,000 Btuh	MO	1,251.7	14.6%	182.3	0.1	0.0	8.0	8.0	$84.00	$50.40	1.7
282	Food Sales	Air Cooled Chiller	MO	991.3	9.0%	89.3	0.1	0.0	23.0	23.0	$126.00	$75.60	1.1
283	Food Sales	Water Cooled Chiller	MO	498.0	22.7%	113.2	0.1	0.0	23.0	23.0	$61.00	$36.60	3.0
284	Food Sales	Window Film	RETRO	6,363.6	4.4%	280.0	0.2	0.0	10.0	10.0	$153.81	$92.29	1.7
285	Food Sales	Triple Pane Windows	MO	6,363.6	6.0%	381.8	0.3	0.0	25.0	25.0	$700.00	$420.00	0.9
286	Food Sales	Energy Recovery Ventilator	RETRO	1,044.7	0.0%	0.0	0.0	0.0	15.0	15.0	$1,500.00	$900.00	0.0
287	Food Sales	Heat Pump - 16 SEER (<5 Tons)	MO	2,390.5	7.7%	183.0	0.0	0.0	15.0	15.0	$135.00	$81.00	1.5
288	Food Sales	Heat Pump - 18 SEER(<5 Tons)	MO	2,390.5	14.5%	347.4	0.1	0.1	15.0	15.0	$445.76	$267.46	0.8
289	Food Sales	Heat Pump - 21 SEER(<5 Tons)	MO	2,390.5	20.7%	493.8	0.1	0.1	15.0	15.0	$520.06	$312.04	1.0
290	Food Sales	Heat Pump - 15.0 IEER COP 3.6 (65,000-134,000 Btu/hr)	MO	2,592.8	6.2%	161.4	0.0	0.0	15.0	15.0	$100.00	$60.00	1.7
291	Food Sales	Heat Pump - 16.0 IEER COP 3.8 (65,000-134,000 Btu/hr)	MO	2,592.8	11.5%	298.3	0.1	0.1	15.0	15.0	$171.08	$102.65	1.9
292	Food Sales	Heat Pump - 14.5 IEER COP 3.5 (135,000-239,000 Btu/hr)	MO	2,685.8	6.7%	179.6	0.0	0.0	15.0	15.0	$100.00	$60.00	1.9
293	Food Sales	Heat Pump - 15.5 IEER COP 3.7 (135,000-239,000 Btu/hr)	MO	2,685.8	12.1%	324.9	0.1	0.1	15.0	15.0	$158.10	$94.86	2.2
294	Food Sales	Heat Pump - 12 IEER 3.4 COP (>239,000 Btu/hr)	MO	2,816.4	6.6%	187.1	0.0	0.0	15.0	15.0	$100.00	$60.00	2.0
295	Food Sales	Heat Pump - 13 IEER 3.6 COP (>239,000 Btu/hr)	MO	2,816.4	12.6%	355.5	0.1	0.1	15.0	15.0	$201.80	$121.08	1.9
296	Food Sales	Geothermal HP - 17 EER < 135kbtu	MO	2,687.7	40.8%	1,095.7	0.2	0.3	25.0	25.0	$4,361.00	$2,616.60	0.3
297	Food Sales	Geothermal HP - 19 EER < 135kbtu	MO	2,687.7	44.3%	1,189.4	0.3	0.3	25.0	25.0	$4,361.00	$2,616.60	0.4
298	Food Sales	PTHP - 7,000 to 15,000 Btuh	MO	5,100.2	16.7%	850.0	0.2	0.2	15.0	15.0	$84.00	$50.40	10.9
299	Food Sales	Heat Pump Water Heater	MO	16,398.4	73.3%	12,025.5	1.6	1.8	15.0	15.0	$1,797.00	$1,078.20	5.1
300	Food Sales	Low Flow Faucet Aerator	RETRO	288.3	32.4%	93.3	0.0	0.0	10.0	10.0	$8.00	$4.80	6.4

Big Rivers | **Measure Assumption Tab**

Measure #	Building Type	Measure Name	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW	RC EUL	EE EUL	Measure Cost	Incentive Amount	TRC
301	Food Sales	Pre-Rinse Spray Valves - DI	RETRO	18,058.7	54.2%	9,788.8	1.3	1.5	5.0	5.0	$54.00	$32.40	54.9
302	Food Sales	Ozone Commercial Laundry	MO	2,984.0	25.0%	746.0	0.1	0.1	10.0	10.0	$20,309.70	$12,185.82	0.0
303	Food Sales	Ext LED Replacing 100W MH (24/7)	RETRO	995.8	75.8%	754.8	0.0	0.1	10.0	10.0	$97.00	$58.20	2.9
304	Food Sales	Ext LED Replacing 175W MH (24/7)	RETRO	1,743.6	71.0%	1,238.6	0.0	0.2	10.0	10.0	$123.81	$74.29	3.7
305	Food Sales	Ext LED Replacing 250W MH (24/7)	RETRO	2,490.4	66.6%	1,658.5	0.0	0.2	10.0	10.0	$134.35	$80.61	4.6
306	Food Sales	Ext LED Replacing 400W MH (24/7)	RETRO	3,984.1	64.5%	2,570.2	0.0	0.3	10.0	10.0	$196.16	$117.70	4.9
307	Food Sales	Ext LED Replacing 1000W MH (24/7)	RETRO	9,467.3	70.4%	6,665.7	0.0	0.8	10.0	10.0	$319.31	$191.59	7.8
308	Food Sales	Ext LED Replacing 100W MH (D2D)	RETRO	488.8	75.8%	370.5	0.0	0.0	10.0	10.0	$97.00	$58.20	1.4
309	Food Sales	Ext LED Replacing 175W MH (D2D)	RETRO	855.9	71.0%	608.0	0.0	0.1	10.0	10.0	$123.81	$74.29	1.8
310	Food Sales	Ext LED Replacing 250W MH (D2D)	RETRO	1,222.5	66.6%	814.1	0.0	0.1	10.0	10.0	$134.35	$80.61	2.3
311	Food Sales	Ext LED Replacing 400W MH (D2D)	RETRO	1,955.7	64.5%	1,261.6	0.0	0.2	10.0	10.0	$196.16	$117.70	2.4
312	Food Sales	Ext LED Replacing 1000W MH (D2D)	RETRO	4,647.2	70.4%	3,272.0	0.0	0.4	10.0	10.0	$319.31	$191.59	3.8
313	Food Sales	LED Interior Direction (Track lighting / Wall-Wash Fixture)	RETRO	219.7	73.8%	162.0	0.0	0.0	12.0	12.0	$59.00	$35.40	1.6
314	Food Sales	LED Linear Replacement Lamps (Replacing T8)	RETRO	158.7	51.4%	81.6	0.0	0.0	10.0	10.0	$15.00	$9.00	2.7
315	Food Sales	LED Troffers (Replacing 1-Lamp T8)	RETRO	163.7	34.0%	55.7	0.0	0.0	12.0	12.0	$22.00	$13.20	1.4
316	Food Sales	LED Troffers (Replacing 2-Lamp T8)	RETRO	320.7	51.4%	164.9	0.0	0.0	12.0	12.0	$61.00	$36.60	1.5
317	Food Sales	LED Troffers (Replacing 3-Lamp T8)	RETRO	475.4	54.0%	256.9	0.0	0.0	12.0	12.0	$76.00	$45.60	1.9
318	Food Sales	LED Troffers (Replacing 4-Lamp T8)	RETRO	633.6	54.3%	343.8	0.0	0.0	12.0	12.0	$104.00	$62.40	1.9
319	Food Sales	LED Linear Ambient Fixture (<6000 lumens, replacing T8)	RETRO	320.0	50.3%	160.9	0.0	0.0	12.0	12.0	$46.67	$28.00	2.0
320	Food Sales	LED Linear Ambient Fixture (>6000 lumens, replacing T5HO)	RETRO	844.0	53.2%	448.7	0.1	0.1	12.0	12.0	$152.00	$91.20	1.7
321	Food Sales	LED Low-Bay Fixture	RETRO	883.4	67.0%	591.9	0.1	0.1	12.0	12.0	$42.88	$25.73	7.9
322	Food Sales	LED High-Bay Fixture (Replacing T8 High Bay)	RETRO	1,654.2	57.0%	943.2	0.1	0.1	12.0	12.0	$48.07	$28.84	11.2
323	Food Sales	LED High-Bay Fixture (Replacing Metal Halide)	RETRO	6,639.4	72.3%	4,800.6	0.6	0.6	12.0	12.0	$187.94	$112.76	14.6
324	Food Sales	Fluorescent Delamping	RETRO	141.2	100.0%	141.2	0.0	0.0	11.0	11.0	$18.50	$11.10	4.1
325	Food Sales	Lighting Occupancy Sensor	RETRO	733.7	30.0%	220.1	0.0	0.0	15.0	15.0	$65.40	$39.24	2.3
326	Food Sales	Lighting Daylight Sensor	RETRO	939.6	28.0%	263.1	0.0	0.0	15.0	15.0	$57.50	$34.50	3.1
327	Food Sales	Dual Occupancy / Daylight Sensor	RETRO	419.2	38.0%	159.3	0.0	0.0	15.0	15.0	$75.00	$45.00	1.4
328	Food Sales	Luminaire-Level Lighting Controls	RETRO	419.2	61.0%	255.7	0.0	0.0	15.0	15.0	$56.00	$33.60	3.1
329	Food Sales	Networked Lighting Control	RETRO	3.4	35.0%	1.2	0.0	0.0	15.0	15.0	$0.71	$0.43	1.1
330	Food Sales	LED Exit Sign	RETRO	63.1	71.4%	45.1	0.0	0.0	5.0	5.0	$32.50	$19.50	0.4
331	Food Sales	Non-Refrigerated Vending Machine Controls	RETRO	385.4	61.4%	236.8	0.0	0.0	5.0	5.0	$233.00	$139.80	0.3
332	Food Sales	Kitchen Exhaust Hood Demand Ventilation Control System	MO	5.3	50.0%	2.6	0.0	0.0	20.0	20.0	$1.73	$1.04	1.5
333	Food Sales	High Efficiency Hand Dryers	MO	3,818.9	83.0%	3,170.4	0.6	0.4	10.0	10.0	$483.00	$289.80	3.9
334	Food Sales	ENERGY STAR Uninterrupted Power Supply	RETRO	3,125.1	3.7%	114.4	0.0	0.0	15.0	15.0	$59.00	$35.40	1.6
335	Food Sales	Miscellaneous Custom	RETRO	6.7	15.0%	1.0	0.0	0.0	10.0	10.0	$0.40	$0.24	1.5
336	Food Sales	Pump and Fan Variable Frequency Drive Controls (Pumps)	MO	3,823.1	27.7%	1,060.3	0.1	0.1	15.0	15.0	$198.32	$118.99	3.5
337	Food Sales	Power Drive Systems	RETRO	4.3	23.0%	1.0	0.0	0.0	15.0	15.0	$0.13	$0.08	5.1
338	Food Sales	Switch Reluctance Motors	MO	37,734.8	30.6%	11,546.9	1.4	1.2	15.0	15.0	$527.50	$316.50	14.4
339	Food Sales	Energy Star Printer/Copier/Fax	MO	418.0	26.3%	110.0	0.0	0.0	6.0	6.0	$0.00	$0.00	0.0
340	Food Sales	Advanced Power Strip – Teri 1 Commercial Use	RETRO	188.2	57.7%	108.6	0.0	0.0	7.0	7.0	$10.00	$6.00	4.8
341	Food Sales	Smart Socket	RETRO	79.9	60.6%	48.4	0.0	0.0	7.0	7.0	$9.00	$5.40	2.4
342	Food Sales	Energy Star Server	MO	2,166.7	30.0%	650.0	0.1	0.1	9.0	9.0	$300.95	$180.57	1.2
343	Food Sales	Server Virtualization	RETRO	2,166.7	13.9%	301.1	0.1	0.0	9.0	9.0	$26.97	$16.18	6.1
344	Food Sales	Electrically Commutated Plug Fans in data centers	RETRO	86,783.0	18.2%	15,778.0	3.2	2.0	15.0	15.0	$480.00	$288.00	26.8
345	Food Sales	Computer Room Air Conditioner Economizer	RETRO	764.0	46.9%	358.0	0.1	0.0	15.0	15.0	$82.00	$49.20	3.6
346	Food Sales	High Efficiency CRAC unit	MO	8,940.1	25.3%	2,264.8	0.5	0.3	20.0	20.0	$750.00	$450.00	3.1
347	Food Sales	Data Center Hot/Cold Aisle Configuration	RETRO	13.3	7.5%	1.0	0.0	0.0	10.0	10.0	$0.23	$0.14	2.6
348	Food Sales	Strip Curtains	RETRO	411.8	50.0%	205.9	0.0	0.0	4.0	4.0	$10.22	$6.13	4.5
349	Food Sales	Floating Head Pressure Controls	RETRO	1,228.0	25.0%	307.0	0.0	0.0	15.0	15.0	$431.00	$258.60	0.5
350	Food Sales	Electronically Commutated (EC) Walk-In Evaporator Fan Motor	RETRO	2,883.6	55.0%	1,586.0	0.2	0.2	15.0	15.0	$305.00	$183.00	3.5

Big Rivers | **Measure Assumption Tab**

Measure #	Building Type	Measure Name	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW	RC EUL	EE EUL	Measure Cost	Incentive Amount	TRC
351	Food Sales	Evaporator Fan Motor Controls	RETRO	1,297.6	22.6%	293.0	0.0	0.0	13.0	13.0	$161.75	$97.05	1.1
352	Food Sales	Variable Speed Condenser Fan	RETRO	3,157.9	47.5%	1,500.0	0.2	0.2	15.0	15.0	$1,170.00	$702.00	0.9
353	Food Sales	Door Heater Controls for Cooler	RETRO	578.6	41.5%	240.1	0.0	0.0	10.0	10.0	$79.50	$47.70	1.5
354	Food Sales	Automated Door Closer for Refrigerator	RETRO	1,259,892.8	0.2%	2,398.7	0.3	0.3	8.0	8.0	$502.00	$301.20	2.0
355	Food Sales	Aerofoils for Open Display Cases	RETRO	45,880.0	10.0%	4,588.0	0.6	0.5	10.0	10.0	$311.54	$186.92	7.3
356	Food Sales	Display Case Door Retrofit, Medium Temp	RETRO	1,558.3	50.0%	779.1	0.1	0.1	15.0	15.0	$390.00	$234.00	1.4
357	Food Sales	Electronically Commutated (EC) Reach-In Evaporator Fan Motor	RETRO	2,883.6	55.0%	1,586.0	0.2	0.2	15.0	15.0	$305.00	$183.00	3.5
358	Food Sales	Q-Sync Motor for Walk-In and Reach-in Evaporator Fan Motor	RETRO	2,090.6	24.1%	504.6	0.1	0.1	10.0	10.0	$96.00	$57.60	2.6
359	Food Sales	Night Covers for Coolers	RETRO	1,510.5	9.0%	136.0	0.0	0.0	5.0	5.0	$42.00	$25.20	0.9
360	Food Sales	Door Heater Controls for Freezer	RETRO	2,016.2	32.5%	655.3	0.1	0.1	10.0	10.0	$79.50	$47.70	4.1
361	Food Sales	Automated Door Closer for Freezer	RETRO	1,259,892.8	0.6%	6,948.8	0.8	0.8	8.0	8.0	$502.00	$301.20	5.7
362	Food Sales	Night Covers for Freezers	RETRO	2,349.3	9.0%	211.3	0.0	0.0	5.0	5.0	$42.00	$25.20	1.4
363	Food Sales	Refrigeration - Custom	RETRO	6.7	15.0%	1.0	0.0	0.0	10.0	10.0	$0.40	$0.24	1.2
364	Food Sales	Retro-commissioning_Refrigerator Optimization	RETRO	4.8	21.0%	1.0	0.0	0.0	5.0	5.0	$0.22	$0.13	1.2
365	Food Sales	ESTAR Refrigerated Vending Machine	MO	1,277.5	12.0%	153.3	0.0	0.0	14.0	14.0	$500.00	$300.00	0.2
366	Food Sales	Refrigerated Vending Machine Controls	RETRO	1,662.9	23.5%	390.1	0.0	0.0	5.0	5.0	$245.00	$147.00	0.4
367	Food Sales	Commercial Ice Marker	MO	5,550.9	7.9%	440.3	0.1	0.1	9.0	9.0	$222.00	$133.20	0.9
368	Food Sales	LED Refrigerated Display Case Lighting Average 6W/LF	MO	114.6	73.7%	84.5	0.0	0.0	9.0	9.0	$11.00	$6.60	3.5
369	Food Sales	Pump and Fan Variable Frequency Drive Controls (Fans)	RETRO	16,265.8	59.0%	9,595.6	1.6	1.6	15.0	15.0	$2,250.00	$1,350.00	3.5
370	Food Sales	Cogged V-Belt (Synchronous)	RETRO	19,471.0	3.1%	603.6	0.1	0.1	15.0	15.0	$381.00	$228.60	1.2
371	Food Sales	HVAC - Energy Management System	RETRO	12.5	8.0%	1.0	0.0	0.0	15.0	15.0	$0.40	$0.24	1.8
372	Food Sales	GREM Controls	RETRO	0.0	0.0%	0.0	0.0	0.0	15.0	15.0	$0.00	$0.00	0.0
373	Food Sales	Demand Control Ventilation	RETRO	0.0	0.0%	0.0	0.0	0.0	10.0	10.0	$235.60	$141.36	0.0
374	Food Sales	High Efficiency DOAS	RETRO	5.2	35.7%	1.9	0.0	0.0	15.0	15.0	$15.22	$9.13	0.1
375	Food Sales	Advanced Rooftop Controls	RETRO	1,107.8	44.4%	491.4	0.1	0.1	10.0	10.0	$341.21	$204.72	0.8
376	Food Sales	Retro-commissioning_Bld Optimization	RETRO	12.5	8.0%	1.0	0.0	0.0	15.0	15.0	$0.12	$0.07	6.0
377	Food Sales	Commercial Weatherstripping	RETRO	222.3	2.0%	4.4	0.0	0.0	10.0	10.0	$8.00	$4.80	0.3
378	Food Sales	WholeBlg - Com RET	RETRO	6.7	15.0%	1.0	0.0	0.0	15.0	15.0	$0.40	$0.24	1.8
379	Food Sales	Strategic Energy Management	RETRO	0.0	0.0%	0.0	0.0	0.0	5.0	5.0	$0.27	$0.16	0.6
380	Food Sales	Power Distribution Equipment Upgrades (Transformers)	RETRO	990.2	0.6%	5.5	0.0	0.0	30.0	30.0	$6.27	$3.76	0.8
381	Food Sales	WholeBlg - Com NC	NC	4.0	25.0%	1.0	0.0	0.0	15.0	15.0	$0.40	$0.24	1.8
382	Food Service	Commercial Combination Oven (Electric)	MO	19,496.1	38.6%	7,532.5	1.1	1.2	12.0	12.0	$2,270.00	$1,362.00	2.2
383	Food Service	Commercial Electric Convection Oven	MO	10,863.7	19.0%	2,064.2	0.3	0.3	12.0	12.0	$960.00	$576.00	1.4
384	Food Service	Commercial Electric Griddle	MO	17,056.0	15.2%	2,596.0	0.4	0.4	12.0	12.0	$0.00	$0.00	0.0
385	Food Service	Commercial Electric Steam Cooker	MO	16,914.5	79.9%	13,506.7	1.9	2.2	12.0	12.0	$2,757.00	$1,654.20	3.3
386	Food Service	Dishwasher Low Temp Door (Energy Star)	MO	35,655.0	44.2%	15,765.8	2.2	2.6	16.0	16.0	$466.50	$279.90	28.0
387	Food Service	Dishwasher High Temp Door (Energy Star)	MO	38,282.0	16.4%	6,278.8	0.9	1.0	15.0	15.0	$1,550.00	$930.00	3.2
388	Food Service	Energy efficient electric fryer	MO	18,955.0	17.3%	3,274.0	0.5	0.5	12.0	12.0	$1,500.00	$900.00	1.4
389	Food Service	Insulated Holding Cabinets	MO	1,478.3	36.9%	545.3	0.1	0.1	12.0	12.0	$1,000.00	$600.00	0.4
390	Food Service	Compressed Air Leak Repair	RETRO	5.9	17.0%	1.0	0.0	0.0	3.0	3.0	$0.08	$0.05	2.2
391	Food Service	Retro-commissioning_Compressed Air Optimization	RETRO	4.8	21.0%	1.0	0.0	0.0	5.0	5.0	$0.22	$0.13	1.2
392	Food Service	Efficient Air Compressors (VSD)	MO	23,741.6	20.8%	4,935.1	0.6	0.5	13.0	13.0	$3,367.84	$2,020.70	0.9
393	Food Service	No Loss Condensate Drain	RETRO	476,153.6	0.4%	1,969.7	0.3	0.2	10.0	10.0	$244.00	$146.40	4.0
394	Food Service	Efficient Air Nozzles	MO	1,129.7	50.0%	564.9	0.1	0.1	15.0	15.0	$57.00	$34.20	6.7
395	Food Service	Air Conditioner - 17 IEER (5-20 Tons)	MO	1,028.8	14.1%	145.2	0.1	0.0	15.0	15.0	$153.28	$91.97	1.0
396	Food Service	Air Conditioner - 18 IEER (5-20 Tons)	MO	1,028.8	18.9%	194.3	0.1	0.0	15.0	15.0	$214.59	$128.75	1.0
397	Food Service	Air Conditioner - 21 IEER (5-20 Tons)	MO	1,028.8	30.5%	313.5	0.2	0.0	15.0	15.0	$398.52	$239.11	0.8
398	Food Service	Air Conditioner - 14.3 IEER (20+ Tons)	MO	1,155.4	9.1%	105.0	0.1	0.0	15.0	15.0	$71.00	$42.60	1.6
399	Food Service	Air Conditioner - 15 IEER (20+ Tons)	MO	1,155.4	13.3%	154.1	0.1	0.0	15.0	15.0	$109.23	$65.54	1.5
400	Food Service	Air Conditioner - 17 IEER (20+ Tons)	MO	1,155.4	23.5%	271.9	0.1	0.0	15.0	15.0	$218.46	$131.08	1.3

Big Rivers | **Measure Assumption Tab**

Measure #	Building Type	Measure Name	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW	RC EUL	EE EUL	Measure Cost	Incentive Amount	TRC
401	Food Service	Comprehensive Rooftop Unit Quality Maintenance (AC Tune-up)	RETRO	1,251.7	7.0%	87.7	0.0	0.0	3.0	3.0	$11.42	$6.85	2.0
402	Food Service	Air Side Economizer	RETRO	1,028.8	20.0%	205.8	0.1	0.0	10.0	10.0	$126.67	$76.00	1.3
403	Food Service	HVAC Occupancy Controls	RETRO	1,085.7	20.0%	217.1	0.1	0.0	15.0	15.0	$197.50	$118.50	1.2
404	Food Service	Air Conditioner - 16 SEER (<5 Tons)	MO	1,072.9	12.5%	134.1	0.1	0.0	15.0	15.0	$115.00	$69.00	1.3
405	Food Service	Air Conditioner - 18 SEER(<5 Tons)	MO	1,072.9	22.2%	238.4	0.1	0.0	15.0	15.0	$514.00	$308.40	0.5
406	Food Service	Air Conditioner - 21 SEER (<5 Tons)	MO	1,072.9	33.3%	357.6	0.2	0.0	15.0	15.0	$630.50	$378.30	0.6
407	Food Service	Smart Thermostat	RETRO	6,157.7	14.2%	871.9	0.4	0.0	11.0	11.0	$175.00	$105.00	4.2
408	Food Service	PTAC - 7,000 to 15,000 Btuh	MO	1,384.4	14.6%	201.7	0.1	0.0	8.0	8.0	$84.00	$50.40	1.5
409	Food Service	Air Cooled Chiller	MO	1,096.4	9.0%	98.8	0.1	0.0	23.0	23.0	$126.00	$75.60	1.0
410	Food Service	Water Cooled Chiller	MO	550.8	22.7%	125.2	0.1	0.0	23.0	23.0	$61.00	$36.60	2.7
411	Food Service	Window Film	RETRO	6,363.6	4.4%	280.0	0.1	0.0	10.0	10.0	$153.81	$92.29	1.4
412	Food Service	Triple Pane Windows	MO	6,363.6	6.0%	381.8	0.2	0.0	25.0	25.0	$700.00	$420.00	0.7
413	Food Service	Energy Recovery Ventilator	RETRO	1,155.4	0.0%	0.0	0.0	0.0	15.0	15.0	$1,500.00	$900.00	0.0
414	Food Service	Heat Pump - 16 SEER (<5 Tons)	MO	2,300.7	8.1%	187.5	0.0	0.0	15.0	15.0	$135.00	$81.00	1.2
415	Food Service	Heat Pump - 18 SEER(<5 Tons)	MO	2,300.7	15.3%	352.3	0.1	0.1	15.0	15.0	$445.76	$267.46	0.7
416	Food Service	Heat Pump - 21 SEER(<5 Tons)	MO	2,300.7	21.9%	505.0	0.1	0.1	15.0	15.0	$520.06	$312.04	0.9
417	Food Service	Heat Pump - 15.0 IEER COP 3.6 (65,000-134,000 Btu/hr)	MO	2,477.2	6.3%	156.8	0.0	0.0	15.0	15.0	$100.00	$60.00	1.4
418	Food Service	Heat Pump - 16.0 IEER COP 3.8 (65,000-134,000 Btu/hr)	MO	2,477.2	11.7%	288.8	0.0	0.1	15.0	15.0	$171.08	$102.65	1.5
419	Food Service	Heat Pump - 14.5 IEER COP 3.5 (135,000-239,000 Btu/hr)	MO	2,568.3	6.8%	175.7	0.0	0.0	15.0	15.0	$100.00	$60.00	1.6
420	Food Service	Heat Pump - 15.5 IEER COP 3.7 (135,000-239,000 Btu/hr)	MO	2,568.3	12.3%	315.9	0.1	0.1	15.0	15.0	$158.10	$94.86	1.8
421	Food Service	Heat Pump - 12 IEER 3.4 COP (>239,000 Btu/hr)	MO	2,701.2	6.9%	185.4	0.0	0.0	15.0	15.0	$100.00	$60.00	1.7
422	Food Service	Heat Pump - 13 IEER 3.6 COP (>239,000 Btu/hr)	MO	2,701.2	12.9%	347.7	0.1	0.1	15.0	15.0	$201.80	$121.08	1.5
423	Food Service	Geothermal HP - 17 EER < 135kbtu	MO	2,569.9	38.7%	993.5	0.2	0.2	25.0	25.0	$4,361.00	$2,616.60	0.3
424	Food Service	Geothermal HP - 19 EER < 135kbtu	MO	2,569.9	42.3%	1,086.3	0.2	0.2	25.0	25.0	$4,361.00	$2,616.60	0.3
425	Food Service	PTHP - 7,000 to 15,000 Btuh	MO	4,675.2	16.7%	779.2	0.1	0.2	15.0	15.0	$84.00	$50.40	8.3
426	Food Service	Heat Pump Water Heater	MO	19,317.8	73.3%	14,166.4	2.4	2.2	15.0	15.0	$1,797.00	$1,078.20	6.4
427	Food Service	Low Flow Faucet Aerator	RETRO	1,001.0	32.4%	324.1	0.1	0.1	10.0	10.0	$8.00	$4.80	24.0
428	Food Service	Pre-Rinse Spray Valves - DI	RETRO	18,058.7	54.2%	9,788.8	1.7	1.5	5.0	5.0	$54.00	$32.40	59.2
429	Food Service	Ozone Commercial Laundry	MO	2,984.0	25.0%	746.0	0.1	0.1	10.0	10.0	$20,309.70	$12,185.82	0.0
430	Food Service	Ext LED Replacing 100W MH (24/7)	RETRO	995.8	75.8%	754.8	0.0	0.1	10.0	10.0	$97.00	$58.20	2.8
431	Food Service	Ext LED Replacing 175W MH (24/7)	RETRO	1,743.6	71.0%	1,238.6	0.0	0.1	10.0	10.0	$123.81	$74.29	3.6
432	Food Service	Ext LED Replacing 250W MH (24/7)	RETRO	2,490.4	66.6%	1,658.5	0.0	0.2	10.0	10.0	$134.35	$80.61	4.4
433	Food Service	Ext LED Replacing 400W MH (24/7)	RETRO	3,984.1	64.5%	2,570.2	0.0	0.3	10.0	10.0	$196.16	$117.70	4.7
434	Food Service	Ext LED Replacing 1000W MH (24/7)	RETRO	9,467.3	70.4%	6,665.7	0.0	0.8	10.0	10.0	$319.31	$191.59	7.5
435	Food Service	Ext LED Replacing 100W MH (D2D)	RETRO	488.8	75.8%	370.5	0.0	0.0	10.0	10.0	$97.00	$58.20	1.4
436	Food Service	Ext LED Replacing 175W MH (D2D)	RETRO	855.9	71.0%	608.0	0.0	0.1	10.0	10.0	$123.81	$74.29	1.8
437	Food Service	Ext LED Replacing 250W MH (D2D)	RETRO	1,222.5	66.6%	814.1	0.0	0.1	10.0	10.0	$134.35	$80.61	2.2
438	Food Service	Ext LED Replacing 400W MH (D2D)	RETRO	1,955.7	64.5%	1,261.6	0.0	0.1	10.0	10.0	$196.16	$117.70	2.3
439	Food Service	Ext LED Replacing 1000W MH (D2D)	RETRO	4,647.2	70.4%	3,272.0	0.0	0.4	10.0	10.0	$319.31	$191.59	3.7
440	Food Service	LED Interior Direction (Track lighting / Wall-Wash Fixture)	RETRO	230.3	73.8%	169.8	0.0	0.0	12.0	12.0	$59.00	$35.40	1.8
441	Food Service	LED Linear Replacement Lamps (Replacing T8)	RETRO	166.3	51.4%	85.5	0.0	0.0	10.0	10.0	$15.00	$9.00	3.1
442	Food Service	LED Troffers (Replacing 1-Lamp T8)	RETRO	171.6	34.0%	58.4	0.0	0.0	12.0	12.0	$22.00	$13.20	1.7
443	Food Service	LED Troffers (Replacing 2-Lamp T8)	RETRO	336.1	51.4%	172.8	0.0	0.0	12.0	12.0	$61.00	$36.60	1.8
444	Food Service	LED Troffers (Replacing 3-Lamp T8)	RETRO	498.2	54.0%	269.3	0.0	0.0	12.0	12.0	$76.00	$45.60	2.2
445	Food Service	LED Troffers (Replacing 4-Lamp T8)	RETRO	663.9	54.3%	360.3	0.1	0.0	12.0	12.0	$104.00	$62.40	2.2
446	Food Service	LED Linear Ambient Fixture (<6000 lumens, replacing T8)	RETRO	335.3	50.3%	168.6	0.0	0.0	12.0	12.0	$46.67	$28.00	2.3
447	Food Service	LED Linear Ambient Fixture (>6000 lumens, replacing T5HO)	RETRO	884.5	53.2%	470.2	0.1	0.1	12.0	12.0	$152.00	$91.20	1.9
448	Food Service	LED Low-Bay Fixture	RETRO	925.7	67.0%	620.3	0.1	0.1	12.0	12.0	$42.88	$25.73	9.1
449	Food Service	LED High-Bay Fixture (Replacing T8 High Bay)	RETRO	1,733.5	57.0%	988.4	0.2	0.1	12.0	12.0	$48.07	$28.84	13.0
450	Food Service	LED High-Bay Fixture (Replacing Metal Halide)	RETRO	6,957.7	72.3%	5,030.8	0.8	0.7	12.0	12.0	$187.94	$112.76	16.9

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Measure #	Building Type	Measure Name	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW	RC EUL	EE EUL	Measure Cost	Incentive Amount	TRC
451	Food Service	Fluorescent Delamping	RETRO	148.0	100.0%	148.0	0.0	0.0	11.0	11.0	$18.50	$11.10	4.7
452	Food Service	Lighting Occupancy Sensor	RETRO	768.9	30.0%	230.7	0.0	0.0	15.0	15.0	$65.40	$39.24	2.6
453	Food Service	Lighting Daylight Sensor	RETRO	984.7	28.0%	275.7	0.0	0.0	15.0	15.0	$57.50	$34.50	3.6
454	Food Service	Dual Occupancy / Daylight Sensor	RETRO	439.3	38.0%	166.9	0.0	0.0	15.0	15.0	$75.00	$45.00	1.7
455	Food Service	Luminaire-Level Lighting Controls	RETRO	439.3	61.0%	268.0	0.0	0.0	15.0	15.0	$56.00	$33.60	3.6
456	Food Service	Networked Lighting Control	RETRO	3.6	35.0%	1.3	0.0	0.0	15.0	15.0	$0.74	$0.45	1.3
457	Food Service	LED Exit Sign	RETRO	64.9	71.4%	46.4	0.0	0.0	5.0	5.0	$32.50	$19.50	0.4
458	Food Service	Non-Refrigerated Vending Machine Controls	RETRO	385.4	61.4%	236.8	0.0	0.0	5.0	5.0	$233.00	$139.80	0.3
459	Food Service	Kitchen Exhaust Hood Demand Ventilation Control System	MO	2.4	50.0%	1.2	0.0	0.0	20.0	20.0	$1.73	$1.04	0.6
460	Food Service	High Efficiency Hand Dryers	MO	1,909.5	83.0%	1,585.2	0.2	0.2	10.0	10.0	$483.00	$289.80	1.6
461	Food Service	ENERGY STAR Uninterrupted Power Supply	RETRO	3,125.1	3.7%	114.4	0.0	0.0	15.0	15.0	$59.00	$35.40	1.3
462	Food Service	Miscellaneous Custom	RETRO	6.7	15.0%	1.0	0.0	0.0	10.0	10.0	$0.40	$0.24	1.2
463	Food Service	Pump and Fan Variable Frequency Drive Controls (Pumps)	MO	1,611.0	27.7%	446.8	0.1	0.0	15.0	15.0	$198.32	$118.99	1.5
464	Food Service	Power Drive Systems	RETRO	4.3	23.0%	1.0	0.0	0.0	15.0	15.0	$0.13	$0.08	5.2
465	Food Service	Switch Reluctance Motors	MO	33,405.7	30.6%	10,222.1	1.3	1.1	15.0	15.0	$527.50	$316.50	13.1
466	Food Service	Energy Star Printer/Copier/Fax	MO	418.0	26.3%	110.0	0.0	0.0	6.0	6.0	$0.00	$0.00	0.0
467	Food Service	Advanced Power Strip – Teri 1 Commercial Use	RETRO	188.2	57.7%	108.6	0.0	0.0	7.0	7.0	$10.00	$6.00	4.0
468	Food Service	Smart Socket	RETRO	79.9	60.6%	48.4	0.0	0.0	7.0	7.0	$9.00	$5.40	2.0
469	Food Service	Energy Star Server	MO	2,166.7	30.0%	650.0	0.1	0.1	9.0	9.0	$300.95	$180.57	1.0
470	Food Service	Server Virtualization	RETRO	2,166.7	13.9%	301.1	0.0	0.0	9.0	9.0	$26.97	$16.18	5.0
471	Food Service	Electrically Commutated Plug Fans in data centers	RETRO	86,783.0	18.2%	15,778.0	2.0	1.7	15.0	15.0	$480.00	$288.00	22.3
472	Food Service	Computer Room Air Conditioner Economizer	RETRO	764.0	46.9%	358.0	0.0	0.0	15.0	15.0	$82.00	$49.20	3.0
473	Food Service	High Efficiency CRAC unit	MO	8,940.1	25.3%	2,264.8	0.3	0.3	20.0	20.0	$750.00	$450.00	2.5
474	Food Service	Data Center Hot/Cold Aisle Configuration	RETRO	13.3	7.5%	1.0	0.0	0.0	10.0	10.0	$0.23	$0.14	2.2
475	Food Service	Strip Curtains	RETRO	87.7	50.0%	43.9	0.0	0.0	4.0	4.0	$10.22	$6.13	1.0
476	Food Service	Floating Head Pressure Controls	RETRO	1,228.0	25.0%	307.0	0.0	0.0	15.0	15.0	$431.00	$258.60	0.5
477	Food Service	Electronically Commutated (EC) Walk-In Evaporator Fan Motor	RETRO	2,883.6	55.0%	1,586.0	0.2	0.2	15.0	15.0	$305.00	$183.00	3.6
478	Food Service	Evaporator Fan Motor Controls	RETRO	1,297.6	22.6%	293.0	0.0	0.0	13.0	13.0	$161.75	$97.05	1.1
479	Food Service	Variable Speed Condenser Fan	RETRO	3,157.9	47.5%	1,500.0	0.2	0.2	15.0	15.0	$1,170.00	$702.00	0.9
480	Food Service	Door Heater Controls for Cooler	RETRO	578.6	41.5%	240.1	0.0	0.0	10.0	10.0	$79.50	$47.70	1.5
481	Food Service	Automated Door Closer for Refrigerator	RETRO	1,259,892.8	0.2%	2,398.7	0.3	0.3	8.0	8.0	$502.00	$301.20	2.0
482	Food Service	Aerofoils for Open Display Cases	RETRO	45,880.0	10.0%	4,588.0	0.7	0.5	10.0	10.0	$311.54	$186.92	7.4
483	Food Service	Display Case Door Retrofit, Medium Temp	RETRO	1,558.3	50.0%	779.1	0.1	0.1	15.0	15.0	$390.00	$234.00	1.4
484	Food Service	Electronically Commutated (EC) Reach-In Evaporator Fan Motor	RETRO	2,883.6	55.0%	1,586.0	0.2	0.2	15.0	15.0	$305.00	$183.00	3.6
485	Food Service	Q-Sync Motor for Walk-In and Reach-in Evaporator Fan Motor	RETRO	2,090.6	24.1%	504.6	0.1	0.1	10.0	10.0	$96.00	$57.60	2.7
486	Food Service	Night Covers for Coolers	RETRO	1,510.5	9.0%	136.0	0.0	0.0	5.0	5.0	$42.00	$25.20	0.9
487	Food Service	Door Heater Controls for Freezer	RETRO	2,016.2	32.5%	655.3	0.1	0.1	10.0	10.0	$79.50	$47.70	4.2
488	Food Service	Automated Door Closer for Freezer	RETRO	1,259,892.8	0.6%	6,948.8	1.0	0.7	8.0	8.0	$502.00	$301.20	5.8
489	Food Service	Night Covers for Freezers	RETRO	2,349.3	9.0%	211.3	0.0	0.0	5.0	5.0	$42.00	$25.20	1.4
490	Food Service	Refrigeration - Custom	RETRO	6.7	15.0%	1.0	0.0	0.0	10.0	10.0	$0.40	$0.24	1.3
491	Food Service	Retro-commissioning_Refrigerator Optimization	RETRO	4.8	21.0%	1.0	0.0	0.0	5.0	5.0	$0.22	$0.13	1.3
492	Food Service	ESTAR Refrigerated Vending Machine	MO	1,277.5	12.0%	153.3	0.0	0.0	14.0	14.0	$500.00	$300.00	0.2
493	Food Service	Refrigerated Vending Machine Controls	RETRO	1,662.9	23.5%	390.1	0.1	0.0	5.0	5.0	$245.00	$147.00	0.4
494	Food Service	Commercial Ice Marker	MO	5,550.9	7.9%	440.3	0.1	0.0	9.0	9.0	$222.00	$133.20	0.9
495	Food Service	LED Refrigerated Display Case Lighting Average 6W/LF	MO	114.6	73.7%	84.5	0.0	0.0	9.0	9.0	$11.00	$6.60	3.5
496	Food Service	Pump and Fan Variable Frequency Drive Controls (Fans)	RETRO	13,902.9	59.0%	8,201.7	1.4	1.3	15.0	15.0	$2,250.00	$1,350.00	3.0
497	Food Service	Cogged V-Belt (Synchronous)	RETRO	17,237.2	3.1%	534.4	0.1	0.1	15.0	15.0	$381.00	$228.60	1.0
498	Food Service	HVAC - Energy Management System	RETRO	12.5	8.0%	1.0	0.0	0.0	15.0	15.0	$0.40	$0.24	1.9
499	Food Service	GREM Controls	RETRO	0.0	0.0%	0.0	0.0	0.0	15.0	15.0	$0.00	$0.00	0.0
500	Food Service	Demand Control Ventilation	RETRO	2,550.0	20.0%	510.0	0.1	0.1	10.0	10.0	$235.60	$141.36	1.2

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Measure #	Building Type	Measure Name	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW	RC EUL	EE EUL	Measure Cost	Incentive Amount	TRC
501	Food Service	High Efficiency DOAS	RETRO	5.2	35.7%	1.9	0.0	0.0	15.0	15.0	$15.22	$9.13	0.1
502	Food Service	Advanced Rooftop Controls	RETRO	1,237.5	46.9%	579.9	0.1	0.1	10.0	10.0	$341.21	$204.72	1.0
503	Food Service	Retro-commissioning_Bld Optimization	RETRO	12.5	8.0%	1.0	0.0	0.0	15.0	15.0	$0.12	$0.07	6.4
504	Food Service	Commercial Weatherstripping	RETRO	222.3	2.0%	4.4	0.0	0.0	10.0	10.0	$8.00	$4.80	0.3
505	Food Service	WholeBlg - Com RET	RETRO	6.7	15.0%	1.0	0.0	0.0	15.0	15.0	$0.40	$0.24	1.9
506	Food Service	Strategic Energy Management	RETRO	0.0	0.0%	0.0	0.0	0.0	5.0	5.0	$0.27	$0.16	0.7
507	Food Service	Power Distribution Equipment Upgrades (Transformers)	RETRO	990.2	0.6%	5.5	0.0	0.0	30.0	30.0	$6.27	$3.76	0.8
508	Food Service	WholeBlg - Com NC	NC	4.0	25.0%	1.0	0.0	0.0	15.0	15.0	$0.40	$0.24	1.9
509	Health	Commercial Combination Oven (Electric)	MO	19,496.1	38.6%	7,532.5	2.3	0.8	12.0	12.0	$2,270.00	$1,362.00	2.6
510	Health	Commercial Electric Convection Oven	MO	10,863.7	19.0%	2,064.2	0.6	0.2	12.0	12.0	$960.00	$576.00	1.7
511	Health	Commercial Electric Griddle	MO	17,056.0	15.2%	2,596.0	0.8	0.3	12.0	12.0	$0.00	$0.00	0.0
512	Health	Commercial Electric Steam Cooker	MO	16,914.5	79.9%	13,506.7	4.1	1.4	12.0	12.0	$2,757.00	$1,654.20	3.8
513	Health	Dishwasher Low Temp Door (Energy Star)	MO	35,655.0	44.2%	15,765.8	4.8	1.6	16.0	16.0	$466.50	$279.90	32.8
514	Health	Dishwasher High Temp Door (Energy Star)	MO	38,282.0	16.4%	6,278.8	1.9	0.6	15.0	15.0	$1,550.00	$930.00	3.7
515	Health	Energy efficient electric fryer	MO	18,955.0	17.3%	3,274.0	1.0	0.3	12.0	12.0	$1,500.00	$900.00	1.7
516	Health	Insulated Holding Cabinets	MO	1,478.3	36.9%	545.3	0.2	0.1	12.0	12.0	$1,000.00	$600.00	0.4
517	Health	Compressed Air Leak Repair	RETRO	5.9	17.0%	1.0	0.0	0.0	3.0	3.0	$0.08	$0.05	2.1
518	Health	Retro-commissioning_Compressed Air Optimization	RETRO	4.8	21.0%	1.0	0.0	0.0	5.0	5.0	$0.22	$0.13	1.2
519	Health	Efficient Air Compressors (VSD)	MO	23,741.6	20.8%	4,935.1	0.6	0.5	13.0	13.0	$3,367.84	$2,020.70	0.9
520	Health	No Loss Condensate Drain	RETRO	476,153.6	0.4%	1,969.7	0.2	0.2	10.0	10.0	$244.00	$146.40	3.9
521	Health	Efficient Air Nozzles	MO	1,129.7	50.0%	564.9	0.1	0.1	15.0	15.0	$57.00	$34.20	6.6
522	Health	Air Conditioner - 17 IEER (5-20 Tons)	MO	1,216.3	14.1%	171.7	0.0	0.0	15.0	15.0	$153.28	$91.97	0.9
523	Health	Air Conditioner - 18 IEER (5-20 Tons)	MO	1,216.3	18.9%	229.7	0.1	0.0	15.0	15.0	$214.59	$128.75	0.8
524	Health	Air Conditioner - 21 IEER (5-20 Tons)	MO	1,216.3	30.5%	370.7	0.1	0.0	15.0	15.0	$398.52	$239.11	0.7
525	Health	Air Conditioner - 14.3 IEER (20+ Tons)	MO	1,366.0	9.1%	124.2	0.0	0.0	15.0	15.0	$71.00	$42.60	1.4
526	Health	Air Conditioner - 15 IEER (20+ Tons)	MO	1,366.0	13.3%	182.1	0.1	0.0	15.0	15.0	$109.23	$65.54	1.3
527	Health	Air Conditioner - 17 IEER (20+ Tons)	MO	1,366.0	23.5%	321.4	0.1	0.0	15.0	15.0	$218.46	$131.08	1.1
528	Health	Comprehensive Rooftop Unit Quality Maintenance (AC Tune-up)	RETRO	1,479.8	7.0%	103.6	0.0	0.0	3.0	3.0	$11.42	$6.85	1.8
529	Health	Air Side Economizer	RETRO	1,216.3	20.0%	243.3	0.1	0.0	10.0	10.0	$126.67	$76.00	1.1
530	Health	HVAC Occupancy Controls	RETRO	1,283.6	20.0%	256.7	0.1	0.0	15.0	15.0	$197.50	$118.50	1.0
531	Health	Air Conditioner - 16 SEER (<5 Tons)	MO	1,268.4	12.5%	158.6	0.0	0.0	15.0	15.0	$115.00	$69.00	1.1
532	Health	Air Conditioner - 18 SEER(<5 Tons)	MO	1,268.4	22.2%	281.9	0.1	0.0	15.0	15.0	$514.00	$308.40	0.4
533	Health	Air Conditioner - 21 SEER (<5 Tons)	MO	1,268.4	33.3%	422.8	0.1	0.0	15.0	15.0	$630.50	$378.30	0.5
534	Health	Smart Thermostat	RETRO	7,279.9	14.2%	1,030.8	0.3	0.0	11.0	11.0	$175.00	$105.00	3.6
535	Health	PTAC - 7,000 to 15,000 Btuh	MO	1,636.7	14.6%	238.4	0.1	0.0	8.0	8.0	$84.00	$50.40	1.3
536	Health	Air Cooled Chiller	MO	1,296.2	9.0%	116.8	0.0	0.0	23.0	23.0	$126.00	$75.60	0.9
537	Health	Water Cooled Chiller	MO	651.1	22.7%	148.0	0.0	0.0	23.0	23.0	$61.00	$36.60	2.3
538	Health	Window Film	RETRO	6,363.6	4.4%	280.0	0.1	0.0	10.0	10.0	$153.81	$92.29	1.0
539	Health	Triple Pane Windows	MO	6,363.6	6.0%	381.8	0.1	0.0	25.0	25.0	$700.00	$420.00	0.5
540	Health	Energy Recovery Ventilator	RETRO	1,366.0	32.7%	446.3	0.1	0.0	15.0	15.0	$1,500.00	$900.00	0.2
541	Health	Heat Pump - 16 SEER (<5 Tons)	MO	2,780.5	8.1%	224.3	0.0	0.1	15.0	15.0	$135.00	$81.00	1.4
542	Health	Heat Pump - 18 SEER(<5 Tons)	MO	2,780.5	15.2%	422.2	0.0	0.1	15.0	15.0	$445.76	$267.46	0.8
543	Health	Heat Pump - 21 SEER(<5 Tons)	MO	2,780.5	21.7%	604.3	0.1	0.1	15.0	15.0	$520.06	$312.04	1.0
544	Health	Heat Pump - 15.0 IEER COP 3.6 (65,000-134,000 Btu/hr)	MO	2,997.5	6.3%	189.2	0.0	0.0	15.0	15.0	$100.00	$60.00	1.6
545	Health	Heat Pump - 16.0 IEER COP 3.8 (65,000-134,000 Btu/hr)	MO	2,997.5	11.6%	348.7	0.0	0.1	15.0	15.0	$171.08	$102.65	1.7
546	Health	Heat Pump - 14.5 IEER COP 3.5 (135,000-239,000 Btu/hr)	MO	3,107.3	6.8%	211.8	0.0	0.0	15.0	15.0	$100.00	$60.00	1.8
547	Health	Heat Pump - 15.5 IEER COP 3.7 (135,000-239,000 Btu/hr)	MO	3,107.3	12.3%	381.1	0.0	0.1	15.0	15.0	$158.10	$94.86	2.0
548	Health	Heat Pump - 12 IEER 3.4 COP (>239,000 Btu/hr)	MO	3,266.5	6.8%	223.0	0.0	0.1	15.0	15.0	$100.00	$60.00	1.9
549	Health	Heat Pump - 13 IEER 3.6 COP (>239,000 Btu/hr)	MO	3,266.5	12.8%	419.1	0.0	0.1	15.0	15.0	$201.80	$121.08	1.7
550	Health	Geothermal HP - 17 EER < 135kbtu	MO	3,109.3	39.0%	1,213.1	0.1	0.3	25.0	25.0	$4,361.00	$2,616.60	0.3

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Measure #	Building Type	Measure Name	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW	RC EUL	EE EUL	Measure Cost	Incentive Amount	TRC
551	Health	Geothermal HP - 19 EER < 135kbtu	MO	3,109.3	42.6%	1,324.7	0.1	0.3	25.0	25.0	$4,361.00	$2,616.60	0.3
552	Health	PTHP - 7,000 to 15,000 Btuh	MO	5,697.6	16.7%	949.6	0.1	0.2	15.0	15.0	$84.00	$50.40	9.4
553	Health	Heat Pump Water Heater	MO	24,473.3	73.3%	17,947.1	1.8	2.1	15.0	15.0	$1,797.00	$1,078.20	6.4
554	Health	Low Flow Faucet Aerator	RETRO	1,297.3	34.5%	447.3	0.0	0.1	10.0	10.0	$14.27	$8.56	14.7
555	Health	Pre-Rinse Spray Valves - DI	RETRO	18,058.7	54.2%	9,788.8	1.0	1.1	5.0	5.0	$54.00	$32.40	47.2
556	Health	Ozone Commercial Laundry	MO	2,984.0	25.0%	746.0	0.1	0.1	10.0	10.0	$20,309.70	$12,185.82	0.0
557	Health	Ext LED Replacing 100W MH (24/7)	RETRO	995.8	75.8%	754.8	0.0	0.1	10.0	10.0	$97.00	$58.20	2.8
558	Health	Ext LED Replacing 175W MH (24/7)	RETRO	1,743.6	71.0%	1,238.6	0.0	0.1	10.0	10.0	$123.81	$74.29	3.6
559	Health	Ext LED Replacing 250W MH (24/7)	RETRO	2,490.4	66.6%	1,658.5	0.0	0.2	10.0	10.0	$134.35	$80.61	4.4
560	Health	Ext LED Replacing 400W MH (24/7)	RETRO	3,984.1	64.5%	2,570.2	0.0	0.3	10.0	10.0	$196.16	$117.70	4.7
561	Health	Ext LED Replacing 1000W MH (24/7)	RETRO	9,467.3	70.4%	6,665.7	0.0	0.8	10.0	10.0	$319.31	$191.59	7.5
562	Health	Ext LED Replacing 100W MH (D2D)	RETRO	488.8	75.8%	370.5	0.0	0.0	10.0	10.0	$97.00	$58.20	1.4
563	Health	Ext LED Replacing 175W MH (D2D)	RETRO	855.9	71.0%	608.0	0.0	0.1	10.0	10.0	$123.81	$74.29	1.8
564	Health	Ext LED Replacing 250W MH (D2D)	RETRO	1,222.5	66.6%	814.1	0.0	0.1	10.0	10.0	$134.35	$80.61	2.2
565	Health	Ext LED Replacing 400W MH (D2D)	RETRO	1,955.7	64.5%	1,261.6	0.0	0.1	10.0	10.0	$196.16	$117.70	2.3
566	Health	Ext LED Replacing 1000W MH (D2D)	RETRO	4,647.2	70.4%	3,272.0	0.0	0.4	10.0	10.0	$319.31	$191.59	3.7
567	Health	LED Interior Direction (Track lighting / Wall-Wash Fixture)	RETRO	251.0	73.8%	185.1	0.0	0.0	12.0	12.0	$59.00	$35.40	1.7
568	Health	LED Linear Replacement Lamps (Replacing T8)	RETRO	181.2	51.4%	93.2	0.0	0.0	10.0	10.0	$15.00	$9.00	2.9
569	Health	LED Troffers (Replacing 1-Lamp T8)	RETRO	187.0	34.0%	63.6	0.0	0.0	12.0	12.0	$22.00	$13.20	1.6
570	Health	LED Troffers (Replacing 2-Lamp T8)	RETRO	366.4	51.4%	188.3	0.0	0.0	12.0	12.0	$61.00	$36.60	1.7
571	Health	LED Troffers (Replacing 3-Lamp T8)	RETRO	543.1	54.0%	293.5	0.0	0.0	12.0	12.0	$76.00	$45.60	2.1
572	Health	LED Troffers (Replacing 4-Lamp T8)	RETRO	723.7	54.3%	392.7	0.0	0.0	12.0	12.0	$104.00	$62.40	2.1
573	Health	LED Linear Ambient Fixture (<6000 lumens, replacing T8)	RETRO	365.5	50.3%	183.8	0.0	0.0	12.0	12.0	$46.67	$28.00	2.2
574	Health	LED Linear Ambient Fixture (>6000 lumens, replacing T5HO)	RETRO	964.1	53.2%	512.6	0.1	0.0	12.0	12.0	$152.00	$91.20	1.8
575	Health	LED Low-Bay Fixture	RETRO	1,009.1	67.0%	676.1	0.1	0.1	12.0	12.0	$42.88	$25.73	8.6
576	Health	LED High-Bay Fixture (Replacing T8 High Bay)	RETRO	1,889.6	57.0%	1,077.4	0.1	0.1	12.0	12.0	$48.07	$28.84	12.3
577	Health	LED High-Bay Fixture (Replacing Metal Halide)	RETRO	7,584.2	72.3%	5,483.7	0.7	0.5	12.0	12.0	$187.94	$112.76	16.0
578	Health	Fluorescent Delamping	RETRO	161.3	100.0%	161.3	0.0	0.0	11.0	11.0	$18.50	$11.10	4.5
579	Health	Lighting Occupancy Sensor	RETRO	838.1	30.0%	251.4	0.0	0.0	15.0	15.0	$65.40	$39.24	2.5
580	Health	Lighting Daylight Sensor	RETRO	1,073.4	28.0%	300.5	0.0	0.0	15.0	15.0	$57.50	$34.50	3.4
581	Health	Dual Occupancy / Daylight Sensor	RETRO	478.8	38.0%	182.0	0.0	0.0	15.0	15.0	$75.00	$45.00	1.6
582	Health	Luminaire-Level Lighting Controls	RETRO	478.8	61.0%	292.1	0.0	0.0	15.0	15.0	$56.00	$33.60	3.4
583	Health	Networked Lighting Control	RETRO	3.9	35.0%	1.4	0.0	0.0	15.0	15.0	$0.81	$0.49	1.1
584	Health	LED Exit Sign	RETRO	68.6	71.4%	49.0	0.0	0.0	5.0	5.0	$32.50	$19.50	0.4
585	Health	Non-Refrigerated Vending Machine Controls	RETRO	385.4	61.4%	236.8	0.0	0.0	5.0	5.0	$233.00	$139.80	0.3
586	Health	Kitchen Exhaust Hood Demand Ventilation Control System	MO	5.3	50.0%	2.6	0.0	0.0	20.0	20.0	$1.73	$1.04	1.3
587	Health	High Efficiency Hand Dryers	MO	1,909.5	83.0%	1,585.2	0.2	0.2	10.0	10.0	$483.00	$289.80	1.6
588	Health	ENERGY STAR Uninterrupted Power Supply	RETRO	3,125.1	3.7%	114.4	0.0	0.0	15.0	15.0	$59.00	$35.40	1.3
589	Health	Miscellaneous Custom	RETRO	6.7	15.0%	1.0	0.0	0.0	10.0	10.0	$0.40	$0.24	1.2
590	Health	Pump and Fan Variable Frequency Drive Controls (Pumps)	MO	4,349.4	27.7%	1,206.2	0.2	0.1	15.0	15.0	$198.32	$118.99	4.1
591	Health	Power Drive Systems	RETRO	4.3	23.0%	1.0	0.0	0.0	15.0	15.0	$0.13	$0.08	5.2
592	Health	Switch Reluctance Motors	MO	33,405.7	30.6%	10,222.1	1.4	1.0	15.0	15.0	$527.50	$316.50	13.2
593	Health	Energy Star Printer/Copier/Fax	MO	418.0	26.3%	110.0	0.0	0.0	6.0	6.0	$0.00	$0.00	0.0
594	Health	Advanced Power Strip – Teri 1 Commercial Use	RETRO	188.2	57.7%	108.6	0.0	0.0	7.0	7.0	$10.00	$6.00	3.9
595	Health	Smart Socket	RETRO	79.9	60.6%	48.4	0.0	0.0	7.0	7.0	$9.00	$5.40	1.9
596	Health	Energy Star Server	MO	2,166.7	30.0%	650.0	0.1	0.1	9.0	9.0	$300.95	$180.57	1.0
597	Health	Server Virtualization	RETRO	2,166.7	13.9%	301.1	0.0	0.0	9.0	9.0	$26.97	$16.18	5.0
598	Health	Electrically Commutated Plug Fans in data centers	RETRO	86,783.0	18.2%	15,778.0	2.0	1.7	15.0	15.0	$480.00	$288.00	21.9
599	Health	Computer Room Air Conditioner Economizer	RETRO	764.0	46.9%	358.0	0.0	0.0	15.0	15.0	$82.00	$49.20	2.9
600	Health	High Efficiency CRAC unit	MO	8,940.1	25.3%	2,264.8	0.3	0.2	20.0	20.0	$750.00	$450.00	2.5

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Measure #	Building Type	Measure Name	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW	RC EUL	EE EUL	Measure Cost	Incentive Amount	TRC
601	Health	Data Center Hot/Cold Aisle Configuration	RETRO	13.3	7.5%	1.0	0.0	0.0	10.0	10.0	$0.23	$0.14	2.1
602	Health	Strip Curtains	RETRO	0.0	0.0%	0.0	0.0	0.0	4.0	4.0	$10.22	$6.13	0.0
603	Health	Floating Head Pressure Controls	RETRO	1,228.0	25.0%	307.0	0.0	0.0	15.0	15.0	$431.00	$258.60	0.5
604	Health	Electronically Commutated (EC) Walk-In Evaporator Fan Motor	RETRO	2,883.6	55.0%	1,586.0	0.2	0.2	15.0	15.0	$305.00	$183.00	3.8
605	Health	Evaporator Fan Motor Controls	RETRO	1,297.6	22.6%	293.0	0.0	0.0	13.0	13.0	$161.75	$97.05	1.2
606	Health	Variable Speed Condenser Fan	RETRO	3,157.9	47.5%	1,500.0	0.2	0.2	15.0	15.0	$1,170.00	$702.00	0.9
607	Health	Door Heater Controls for Cooler	RETRO	578.6	41.5%	240.1	0.0	0.0	10.0	10.0	$79.50	$47.70	1.6
608	Health	Automated Door Closer for Refrigerator	RETRO	1,259,892.8	0.2%	2,398.7	0.4	0.3	8.0	8.0	$502.00	$301.20	2.1
609	Health	Aerofoils for Open Display Cases	RETRO	45,880.0	10.0%	4,588.0	0.7	0.5	10.0	10.0	$311.54	$186.92	7.8
610	Health	Display Case Door Retrofit, Medium Temp	RETRO	1,558.3	50.0%	779.1	0.1	0.1	15.0	15.0	$390.00	$234.00	1.4
611	Health	Electronically Commutated (EC) Reach-In Evaporator Fan Motor	RETRO	2,883.6	55.0%	1,586.0	0.2	0.2	15.0	15.0	$305.00	$183.00	3.8
612	Health	Q-Sync Motor for Walk-In and Reach-in Evaporator Fan Motor	RETRO	2,090.6	24.1%	504.6	0.1	0.1	10.0	10.0	$96.00	$57.60	2.8
613	Health	Night Covers for Coolers	RETRO	1,510.5	9.0%	136.0	0.0	0.0	5.0	5.0	$42.00	$25.20	0.9
614	Health	Door Heater Controls for Freezer	RETRO	2,016.2	32.5%	655.3	0.1	0.1	10.0	10.0	$79.50	$47.70	4.3
615	Health	Automated Door Closer for Freezer	RETRO	1,259,892.8	0.6%	6,948.8	1.1	0.8	8.0	8.0	$502.00	$301.20	6.0
616	Health	Night Covers for Freezers	RETRO	2,349.3	9.0%	211.3	0.0	0.0	5.0	5.0	$42.00	$25.20	1.5
617	Health	Refrigeration - Custom	RETRO	6.7	15.0%	1.0	0.0	0.0	10.0	10.0	$0.40	$0.24	1.3
618	Health	Retro-commissioning_Refrigerator Optimization	RETRO	4.8	21.0%	1.0	0.0	0.0	5.0	5.0	$0.22	$0.13	1.3
619	Health	ESTAR Refrigerated Vending Machine	MO	1,277.5	12.0%	153.3	0.0	0.0	14.0	14.0	$500.00	$300.00	0.2
620	Health	Refrigerated Vending Machine Controls	RETRO	1,662.9	23.5%	390.1	0.1	0.0	5.0	5.0	$245.00	$147.00	0.5
621	Health	Commercial Ice Marker	MO	5,550.9	7.9%	440.3	0.1	0.1	9.0	9.0	$222.00	$133.20	1.0
622	Health	LED Refrigerated Display Case Lighting Average 6W/LF	MO	114.6	73.7%	84.5	0.0	0.0	9.0	9.0	$11.00	$6.60	3.7
623	Health	Pump and Fan Variable Frequency Drive Controls (Fans)	RETRO	11,035.5	59.0%	6,510.2	1.0	0.9	15.0	15.0	$2,250.00	$1,350.00	2.2
624	Health	Cogged V-Belt (Synchronous)	RETRO	17,237.2	3.1%	534.4	0.1	0.1	15.0	15.0	$381.00	$228.60	1.0
625	Health	HVAC - Energy Management System	RETRO	12.5	8.0%	1.0	0.0	0.0	15.0	15.0	$0.40	$0.24	1.7
626	Health	GREM Controls	RETRO	0.0	0.0%	0.0	0.0	0.0	15.0	15.0	$0.00	$0.00	0.0
627	Health	Demand Control Ventilation	RETRO	305.0	20.0%	61.0	0.0	0.0	10.0	10.0	$235.60	$141.36	0.1
628	Health	High Efficiency DOAS	RETRO	5.2	35.7%	1.9	0.0	0.0	15.0	15.0	$15.22	$9.13	0.1
629	Health	Advanced Rooftop Controls	RETRO	0.0	0.0%	0.0	0.0	0.0	10.0	10.0	$341.21	$204.72	0.0
630	Health	Retro-commissioning_Bld Optimization	RETRO	12.5	8.0%	1.0	0.0	0.0	15.0	15.0	$0.12	$0.07	5.8
631	Health	Commercial Weatherstripping	RETRO	222.3	2.0%	4.4	0.0	0.0	10.0	10.0	$8.00	$4.80	0.3
632	Health	WholeBlg - Com RET	RETRO	6.7	15.0%	1.0	0.0	0.0	15.0	15.0	$0.40	$0.24	1.7
633	Health	Strategic Energy Management	RETRO	33.3	3.0%	1.0	0.0	0.0	5.0	5.0	$0.27	$0.16	1.0
634	Health	Power Distribution Equipment Upgrades (Transformers)	RETRO	990.2	0.6%	5.5	0.0	0.0	30.0	30.0	$6.27	$3.76	0.8
635	Health	WholeBlg - Com NC	NC	4.0	25.0%	1.0	0.0	0.0	15.0	15.0	$0.40	$0.24	1.7
636	Lodging	Commercial Combination Oven (Electric)	MO	19,496.1	38.6%	7,532.5	2.4	0.7	12.0	12.0	$2,270.00	$1,362.00	2.6
637	Lodging	Commercial Electric Convection Oven	MO	10,863.7	19.0%	2,064.2	0.7	0.2	12.0	12.0	$960.00	$576.00	1.7
638	Lodging	Commercial Electric Griddle	MO	17,056.0	15.2%	2,596.0	0.8	0.3	12.0	12.0	$0.00	$0.00	0.0
639	Lodging	Commercial Electric Steam Cooker	MO	16,914.5	79.9%	13,506.7	4.3	1.3	12.0	12.0	$2,757.00	$1,654.20	3.9
640	Lodging	Dishwasher Low Temp Door (Energy Star)	MO	35,655.0	44.2%	15,765.8	5.0	1.5	16.0	16.0	$466.50	$279.90	33.4
641	Lodging	Dishwasher High Temp Door (Energy Star)	MO	38,282.0	16.4%	6,278.8	2.0	0.6	15.0	15.0	$1,550.00	$930.00	3.8
642	Lodging	Energy efficient electric fryer	MO	18,955.0	17.3%	3,274.0	1.0	0.3	12.0	12.0	$1,500.00	$900.00	1.7
643	Lodging	Insulated Holding Cabinets	MO	1,478.3	36.9%	545.3	0.2	0.1	12.0	12.0	$1,000.00	$600.00	0.4
644	Lodging	Compressed Air Leak Repair	RETRO	5.9	17.0%	1.0	0.0	0.0	3.0	3.0	$0.08	$0.05	2.3
645	Lodging	Retro-commissioning_Compressed Air Optimization	RETRO	4.8	21.0%	1.0	0.0	0.0	5.0	5.0	$0.22	$0.13	1.3
646	Lodging	Efficient Air Compressors (VSD)	MO	23,741.6	20.8%	4,935.1	0.6	0.7	13.0	13.0	$3,367.84	$2,020.70	0.9
647	Lodging	No Loss Condensate Drain	RETRO	476,153.6	0.4%	1,969.7	0.2	0.3	10.0	10.0	$244.00	$146.40	4.2
648	Lodging	Efficient Air Nozzles	MO	1,129.7	50.0%	564.9	0.1	0.1	15.0	15.0	$57.00	$34.20	7.1
649	Lodging	Air Conditioner - 17 IEER (5-20 Tons)	MO	1,174.3	14.1%	165.8	0.1	0.0	15.0	15.0	$153.28	$91.97	0.9
650	Lodging	Air Conditioner - 18 IEER (5-20 Tons)	MO	1,174.3	18.9%	221.8	0.1	0.0	15.0	15.0	$214.59	$128.75	0.8

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Measure #	Building Type	Measure Name	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW	RC EUL	EE EUL	Measure Cost	Incentive Amount	TRC
651	Lodging	Air Conditioner - 21 IEER (5-20 Tons)	MO	1,174.3	30.5%	357.9	0.1	0.0	15.0	15.0	$398.52	$239.11	0.7
652	Lodging	Air Conditioner - 14.3 IEER (20+ Tons)	MO	1,318.8	9.1%	119.9	0.0	0.0	15.0	15.0	$71.00	$42.60	1.4
653	Lodging	Air Conditioner - 15 IEER (20+ Tons)	MO	1,318.8	13.3%	175.8	0.1	0.0	15.0	15.0	$109.23	$65.54	1.3
654	Lodging	Air Conditioner - 17 IEER (20+ Tons)	MO	1,318.8	23.5%	310.3	0.1	0.0	15.0	15.0	$218.46	$131.08	1.2
655	Lodging	Comprehensive Rooftop Unit Quality Maintenance (AC Tune-up)	RETRO	1,428.7	7.0%	100.0	0.0	0.0	3.0	3.0	$11.42	$6.85	1.8
656	Lodging	Air Side Economizer	RETRO	1,174.3	20.0%	234.9	0.1	0.0	10.0	10.0	$126.67	$76.00	1.1
657	Lodging	HVAC Occupancy Controls	RETRO	1,239.2	20.0%	247.8	0.1	0.0	15.0	15.0	$197.50	$118.50	1.0
658	Lodging	Air Conditioner - 16 SEER (<5 Tons)	MO	1,224.6	12.5%	153.1	0.0	0.0	15.0	15.0	$115.00	$69.00	1.1
659	Lodging	Air Conditioner - 18 SEER(<5 Tons)	MO	1,224.6	22.2%	272.1	0.1	0.0	15.0	15.0	$514.00	$308.40	0.4
660	Lodging	Air Conditioner - 21 SEER (<5 Tons)	MO	1,224.6	33.3%	408.2	0.1	0.0	15.0	15.0	$630.50	$378.30	0.5
661	Lodging	Smart Thermostat	RETRO	7,028.4	14.2%	995.2	0.3	0.0	11.0	11.0	$175.00	$105.00	3.6
662	Lodging	PTAC - 7,000 to 15,000 Btuh	MO	1,580.1	14.6%	230.2	0.1	0.0	8.0	8.0	$84.00	$50.40	1.3
663	Lodging	Air Cooled Chiller	MO	1,251.4	9.0%	112.7	0.0	0.0	23.0	23.0	$126.00	$75.60	0.9
664	Lodging	Water Cooled Chiller	MO	628.6	22.7%	142.9	0.0	0.0	23.0	23.0	$61.00	$36.60	2.4
665	Lodging	Window Film	RETRO	6,363.6	4.4%	280.0	0.1	0.0	10.0	10.0	$153.81	$92.29	1.1
666	Lodging	Triple Pane Windows	MO	6,363.6	6.0%	381.8	0.1	0.0	25.0	25.0	$700.00	$420.00	0.6
667	Lodging	Energy Recovery Ventilator	RETRO	1,318.8	0.0%	0.0	0.0	0.0	15.0	15.0	$1,500.00	$900.00	0.0
668	Lodging	Heat Pump - 16 SEER (<5 Tons)	MO	2,753.3	8.0%	219.5	0.0	0.0	15.0	15.0	$135.00	$81.00	1.3
669	Lodging	Heat Pump - 18 SEER(<5 Tons)	MO	2,753.3	15.0%	414.0	0.0	0.1	15.0	15.0	$445.76	$267.46	0.8
670	Lodging	Heat Pump - 21 SEER(<5 Tons)	MO	2,753.3	21.5%	591.6	0.1	0.1	15.0	15.0	$520.06	$312.04	0.9
671	Lodging	Heat Pump - 15.0 IEER COP 3.6 (65,000-134,000 Btu/hr)	MO	2,972.4	6.3%	187.1	0.0	0.0	15.0	15.0	$100.00	$60.00	1.5
672	Lodging	Heat Pump - 16.0 IEER COP 3.8 (65,000-134,000 Btu/hr)	MO	2,972.4	11.6%	344.9	0.0	0.1	15.0	15.0	$171.08	$102.65	1.6
673	Lodging	Heat Pump - 14.5 IEER COP 3.5 (135,000-239,000 Btu/hr)	MO	3,080.7	6.8%	209.1	0.0	0.0	15.0	15.0	$100.00	$60.00	1.7
674	Lodging	Heat Pump - 15.5 IEER COP 3.7 (135,000-239,000 Btu/hr)	MO	3,080.7	12.2%	376.7	0.0	0.1	15.0	15.0	$158.10	$94.86	1.9
675	Lodging	Heat Pump - 12 IEER 3.4 COP (>239,000 Btu/hr)	MO	3,236.7	6.8%	219.6	0.0	0.0	15.0	15.0	$100.00	$60.00	1.8
676	Lodging	Heat Pump - 13 IEER 3.6 COP (>239,000 Btu/hr)	MO	3,236.7	12.8%	413.7	0.0	0.1	15.0	15.0	$201.80	$121.08	1.7
677	Lodging	Geothermal HP - 17 EER < 135kbtu	MO	3,082.7	39.4%	1,215.0	0.1	0.2	25.0	25.0	$4,361.00	$2,616.60	0.3
678	Lodging	Geothermal HP - 19 EER < 135kbtu	MO	3,082.7	43.0%	1,324.9	0.1	0.3	25.0	25.0	$4,361.00	$2,616.60	0.3
679	Lodging	PTHP - 7,000 to 15,000 Btuh	MO	5,694.6	16.7%	949.1	0.1	0.2	15.0	15.0	$84.00	$50.40	9.2
680	Lodging	Heat Pump Water Heater	MO	22,206.1	73.3%	16,284.5	1.7	2.6	15.0	15.0	$1,797.00	$1,078.20	6.5
681	Lodging	Low Flow Faucet Aerator	RETRO	122.5	32.4%	39.7	0.0	0.0	10.0	10.0	$8.00	$4.80	2.6
682	Lodging	Pre-Rinse Spray Valves - DI	RETRO	18,058.7	54.2%	9,788.8	1.0	1.6	5.0	5.0	$54.00	$32.40	52.5
683	Lodging	Ozone Commercial Laundry	MO	2,984.0	25.0%	746.0	0.1	0.1	10.0	10.0	$20,309.70	$12,185.82	0.0
684	Lodging	Ext LED Replacing 100W MH (24/7)	RETRO	995.8	75.8%	754.8	0.0	0.1	10.0	10.0	$97.00	$58.20	2.8
685	Lodging	Ext LED Replacing 175W MH (24/7)	RETRO	1,743.6	71.0%	1,238.6	0.0	0.1	10.0	10.0	$123.81	$74.29	3.6
686	Lodging	Ext LED Replacing 250W MH (24/7)	RETRO	2,490.4	66.6%	1,658.5	0.0	0.2	10.0	10.0	$134.35	$80.61	4.4
687	Lodging	Ext LED Replacing 400W MH (24/7)	RETRO	3,984.1	64.5%	2,570.2	0.0	0.3	10.0	10.0	$196.16	$117.70	4.7
688	Lodging	Ext LED Replacing 1000W MH (24/7)	RETRO	9,467.3	70.4%	6,665.7	0.0	0.8	10.0	10.0	$319.31	$191.59	7.5
689	Lodging	Ext LED Replacing 100W MH (D2D)	RETRO	488.8	75.8%	370.5	0.0	0.0	10.0	10.0	$97.00	$58.20	1.4
690	Lodging	Ext LED Replacing 175W MH (D2D)	RETRO	855.9	71.0%	608.0	0.0	0.1	10.0	10.0	$123.81	$74.29	1.8
691	Lodging	Ext LED Replacing 250W MH (D2D)	RETRO	1,222.5	66.6%	814.1	0.0	0.1	10.0	10.0	$134.35	$80.61	2.2
692	Lodging	Ext LED Replacing 400W MH (D2D)	RETRO	1,955.7	64.5%	1,261.6	0.0	0.1	10.0	10.0	$196.16	$117.70	2.3
693	Lodging	Ext LED Replacing 1000W MH (D2D)	RETRO	4,647.2	70.4%	3,272.0	0.0	0.4	10.0	10.0	$319.31	$191.59	3.7
694	Lodging	LED Interior Direction (Track lighting / Wall-Wash Fixture)	RETRO	177.9	73.8%	131.2	0.0	0.0	15.0	15.0	$59.00	$35.40	1.5
695	Lodging	LED Linear Replacement Lamps (Replacing T8)	RETRO	128.4	51.4%	66.0	0.0	0.0	10.0	10.0	$15.00	$9.00	2.1
696	Lodging	LED Troffers (Replacing 1-Lamp T8)	RETRO	132.5	34.0%	45.1	0.0	0.0	15.0	15.0	$22.00	$13.20	1.3
697	Lodging	LED Troffers (Replacing 2-Lamp T8)	RETRO	259.6	51.4%	133.5	0.0	0.0	15.0	15.0	$61.00	$36.60	1.4
698	Lodging	LED Troffers (Replacing 3-Lamp T8)	RETRO	384.9	54.0%	208.0	0.0	0.0	15.0	15.0	$76.00	$45.60	1.8
699	Lodging	LED Troffers (Replacing 4-Lamp T8)	RETRO	512.9	54.3%	278.3	0.0	0.0	15.0	15.0	$104.00	$62.40	1.8
700	Lodging	LED Linear Ambient Fixture (<6000 lumens, replacing T8)	RETRO	259.0	50.3%	130.3	0.0	0.0	15.0	15.0	$46.67	$28.00	1.8

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701	Lodging	LED Linear Ambient Fixture (>6000 lumens, replacing T5HO)	RETRO	683.2	53.2%	363.2	0.0	0.0	15.0	15.0	$152.00	$91.20	1.6
702	Lodging	LED Low-Bay Fixture	RETRO	715.1	67.0%	479.2	0.0	0.1	15.0	15.0	$42.88	$25.73	7.3
703	Lodging	LED High-Bay Fixture (Replacing T8 High Bay)	RETRO	1,339.1	57.0%	763.5	0.1	0.1	15.0	15.0	$48.07	$28.84	10.4
704	Lodging	LED High-Bay Fixture (Replacing Metal Halide)	RETRO	5,374.7	72.3%	3,886.2	0.4	0.5	15.0	15.0	$187.94	$112.76	13.6
705	Lodging	Fluorescent Delamping	RETRO	114.3	100.0%	114.3	0.0	0.0	11.0	11.0	$18.50	$11.10	3.2
706	Lodging	Lighting Occupancy Sensor	RETRO	593.9	30.0%	178.2	0.0	0.0	15.0	15.0	$65.40	$39.24	1.8
707	Lodging	Lighting Daylight Sensor	RETRO	760.7	28.0%	213.0	0.0	0.0	15.0	15.0	$57.50	$34.50	2.4
708	Lodging	Dual Occupancy / Daylight Sensor	RETRO	339.3	38.0%	128.9	0.0	0.0	15.0	15.0	$75.00	$45.00	1.1
709	Lodging	Luminaire-Level Lighting Controls	RETRO	339.3	61.0%	207.0	0.0	0.0	15.0	15.0	$56.00	$33.60	2.4
710	Lodging	Networked Lighting Control	RETRO	2.8	35.0%	1.0	0.0	0.0	15.0	15.0	$0.57	$0.34	1.1
711	Lodging	LED Exit Sign	RETRO	65.5	71.4%	46.8	0.0	0.0	5.0	5.0	$32.50	$19.50	0.4
712	Lodging	Non-Refrigerated Vending Machine Controls	RETRO	385.4	61.4%	236.8	0.0	0.0	5.0	5.0	$233.00	$139.80	0.3
713	Lodging	Kitchen Exhaust Hood Demand Ventilation Control System	MO	5.3	50.0%	2.6	0.0	0.0	20.0	20.0	$1.73	$1.04	1.4
714	Lodging	High Efficiency Hand Dryers	MO	261.6	83.0%	217.2	0.0	0.0	10.0	10.0	$483.00	$289.80	0.2
715	Lodging	ENERGY STAR Uninterrupted Power Supply	RETRO	3,125.1	3.7%	114.4	0.0	0.0	15.0	15.0	$59.00	$35.40	1.4
716	Lodging	Miscellaneous Custom	RETRO	6.7	15.0%	1.0	0.0	0.0	10.0	10.0	$0.40	$0.24	1.3
717	Lodging	Pump and Fan Variable Frequency Drive Controls (Pumps)	MO	3,628.1	27.7%	1,006.2	0.1	0.1	15.0	15.0	$198.32	$118.99	3.6
718	Lodging	Power Drive Systems	RETRO	4.3	23.0%	1.0	0.0	0.0	15.0	15.0	$0.13	$0.08	5.5
719	Lodging	Switch Reluctance Motors	MO	56,602.2	30.6%	17,320.3	2.2	2.3	15.0	15.0	$527.50	$316.50	23.4
720	Lodging	Energy Star Printer/Copier/Fax	MO	418.0	26.3%	110.0	0.0	0.0	6.0	6.0	$0.00	$0.00	0.0
721	Lodging	Advanced Power Strip – Teri 1 Commercial Use	RETRO	188.2	57.7%	108.6	0.0	0.0	7.0	7.0	$10.00	$6.00	4.2
722	Lodging	Smart Socket	RETRO	79.9	60.6%	48.4	0.0	0.0	7.0	7.0	$9.00	$5.40	2.1
723	Lodging	Energy Star Server	MO	2,166.7	30.0%	650.0	0.1	0.1	9.0	9.0	$300.95	$180.57	1.0
724	Lodging	Server Virtualization	RETRO	2,166.7	13.9%	301.1	0.0	0.0	9.0	9.0	$26.97	$16.18	5.3
725	Lodging	Electrically Commutated Plug Fans in data centers	RETRO	86,783.0	18.2%	15,778.0	2.0	2.2	15.0	15.0	$480.00	$288.00	23.6
726	Lodging	Computer Room Air Conditioner Economizer	RETRO	764.0	46.9%	358.0	0.0	0.0	15.0	15.0	$82.00	$49.20	3.1
727	Lodging	High Efficiency CRAC unit	MO	8,940.1	25.3%	2,264.8	0.3	0.3	20.0	20.0	$750.00	$450.00	2.7
728	Lodging	Data Center Hot/Cold Aisle Configuration	RETRO	13.3	7.5%	1.0	0.0	0.0	10.0	10.0	$0.23	$0.14	2.3
729	Lodging	Strip Curtains	RETRO	0.0	0.0%	0.0	0.0	0.0	4.0	4.0	$10.22	$6.13	0.0
730	Lodging	Floating Head Pressure Controls	RETRO	1,228.0	25.0%	307.0	0.0	0.0	15.0	15.0	$431.00	$258.60	0.5
731	Lodging	Electronically Commutated (EC) Walk-In Evaporator Fan Motor	RETRO	2,883.6	55.0%	1,586.0	0.2	0.2	15.0	15.0	$305.00	$183.00	3.6
732	Lodging	Evaporator Fan Motor Controls	RETRO	1,297.6	22.6%	293.0	0.0	0.0	13.0	13.0	$161.75	$97.05	1.1
733	Lodging	Variable Speed Condenser Fan	RETRO	3,157.9	47.5%	1,500.0	0.2	0.2	15.0	15.0	$1,170.00	$702.00	0.9
734	Lodging	Door Heater Controls for Cooler	RETRO	578.6	41.5%	240.1	0.0	0.0	10.0	10.0	$79.50	$47.70	1.5
735	Lodging	Automated Door Closer for Refrigerator	RETRO	1,259,892.8	0.2%	2,398.7	0.3	0.3	8.0	8.0	$502.00	$301.20	2.0
736	Lodging	Aerofoils for Open Display Cases	RETRO	45,880.0	10.0%	4,588.0	0.6	0.5	10.0	10.0	$311.54	$186.92	7.4
737	Lodging	Display Case Door Retrofit, Medium Temp	RETRO	1,558.3	50.0%	779.1	0.1	0.1	15.0	15.0	$390.00	$234.00	1.4
738	Lodging	Electronically Commutated (EC) Reach-In Evaporator Fan Motor	RETRO	2,883.6	55.0%	1,586.0	0.2	0.2	15.0	15.0	$305.00	$183.00	3.6
739	Lodging	Q-Sync Motor for Walk-In and Reach-in Evaporator Fan Motor	RETRO	2,090.6	24.1%	504.6	0.1	0.1	10.0	10.0	$96.00	$57.60	2.6
740	Lodging	Night Covers for Coolers	RETRO	1,510.5	9.0%	136.0	0.0	0.0	5.0	5.0	$42.00	$25.20	0.9
741	Lodging	Door Heater Controls for Freezer	RETRO	2,016.2	32.5%	655.3	0.1	0.1	10.0	10.0	$79.50	$47.70	4.1
742	Lodging	Automated Door Closer for Freezer	RETRO	1,259,892.8	0.6%	6,948.8	1.0	0.8	8.0	8.0	$502.00	$301.20	5.8
743	Lodging	Night Covers for Freezers	RETRO	2,349.3	9.0%	211.3	0.0	0.0	5.0	5.0	$42.00	$25.20	1.4
744	Lodging	Refrigeration - Custom	RETRO	6.7	15.0%	1.0	0.0	0.0	10.0	10.0	$0.40	$0.24	1.3
745	Lodging	Retro-commissioning_Refrigerator Optimization	RETRO	4.8	21.0%	1.0	0.0	0.0	5.0	5.0	$0.22	$0.13	1.3
746	Lodging	ESTAR Refrigerated Vending Machine	MO	1,277.5	12.0%	153.3	0.0	0.0	14.0	14.0	$500.00	$300.00	0.2
747	Lodging	Refrigerated Vending Machine Controls	RETRO	1,662.9	23.5%	390.1	0.1	0.0	5.0	5.0	$245.00	$147.00	0.4
748	Lodging	Commercial Ice Marker	MO	5,550.9	7.9%	440.3	0.1	0.0	9.0	9.0	$222.00	$133.20	0.9
749	Lodging	LED Refrigerated Display Case Lighting Average 6W/LF	MO	114.6	73.7%	84.5	0.0	0.0	9.0	9.0	$11.00	$6.60	3.5
750	Lodging	Pump and Fan Variable Frequency Drive Controls (Fans)	RETRO	10,559.5	59.0%	6,229.3	0.9	0.9	15.0	15.0	$2,250.00	$1,350.00	2.1

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Measure #	Building Type	Measure Name	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW	RC EUL	EE EUL	Measure Cost	Incentive Amount	TRC
751	Lodging	Cogged V-Belt (Synchronous)	RETRO	29,206.5	3.1%	905.4	0.1	0.1	15.0	15.0	$381.00	$228.60	1.7
752	Lodging	HVAC - Energy Management System	RETRO	12.5	8.0%	1.0	0.0	0.0	15.0	15.0	$0.40	$0.24	1.8
753	Lodging	GREM Controls	RETRO	4,853.1	19.3%	935.8	0.1	0.1	15.0	15.0	$260.00	$156.00	2.6
754	Lodging	Demand Control Ventilation	RETRO	2,045.0	20.0%	409.0	0.1	0.0	10.0	10.0	$235.60	$141.36	0.9
755	Lodging	High Efficiency DOAS	RETRO	5.2	35.7%	1.9	0.0	0.0	15.0	15.0	$15.22	$9.13	0.1
756	Lodging	Advanced Rooftop Controls	RETRO	0.0	0.0%	0.0	0.0	0.0	10.0	10.0	$341.21	$204.72	0.0
757	Lodging	Retro-commissioning_Bld Optimization	RETRO	12.5	8.0%	1.0	0.0	0.0	15.0	15.0	$0.12	$0.07	6.0
758	Lodging	Commercial Weatherstripping	RETRO	222.3	2.0%	4.4	0.0	0.0	10.0	10.0	$8.00	$4.80	0.3
759	Lodging	WholeBlg - Com RET	RETRO	6.7	15.0%	1.0	0.0	0.0	15.0	15.0	$0.40	$0.24	1.8
760	Lodging	Strategic Energy Management	RETRO	0.0	0.0%	0.0	0.0	0.0	5.0	5.0	$0.27	$0.16	0.6
761	Lodging	Power Distribution Equipment Upgrades (Transformers)	RETRO	990.2	0.6%	5.5	0.0	0.0	30.0	30.0	$6.27	$3.76	0.8
762	Lodging	WholeBlg - Com NC	NC	4.0	25.0%	1.0	0.0	0.0	15.0	15.0	$0.40	$0.24	1.8
763	Retail	Commercial Combination Oven (Electric)	MO	19,496.1	38.6%	7,532.5	1.8	0.8	12.0	12.0	$2,270.00	$1,362.00	2.4
764	Retail	Commercial Electric Convection Oven	MO	10,863.7	19.0%	2,064.2	0.5	0.2	12.0	12.0	$960.00	$576.00	1.5
765	Retail	Commercial Electric Griddle	MO	17,056.0	15.2%	2,596.0	0.6	0.3	12.0	12.0	$0.00	$0.00	0.0
766	Retail	Commercial Electric Steam Cooker	MO	16,914.5	79.9%	13,506.7	3.3	1.4	12.0	12.0	$2,757.00	$1,654.20	3.5
767	Retail	Dishwasher Low Temp Door (Energy Star)	MO	35,655.0	44.2%	15,765.8	3.9	1.7	16.0	16.0	$466.50	$279.90	30.0
768	Retail	Dishwasher High Temp Door (Energy Star)	MO	38,282.0	16.4%	6,278.8	1.5	0.7	15.0	15.0	$1,550.00	$930.00	3.4
769	Retail	Energy efficient electric fryer	MO	18,955.0	17.3%	3,274.0	0.8	0.3	12.0	12.0	$1,500.00	$900.00	1.6
770	Retail	Insulated Holding Cabinets	MO	1,478.3	36.9%	545.3	0.1	0.1	12.0	12.0	$1,000.00	$600.00	0.4
771	Retail	Compressed Air Leak Repair	RETRO	5.9	17.0%	1.0	0.0	0.0	3.0	3.0	$0.08	$0.05	2.1
772	Retail	Retro-commissioning_Compressed Air Optimization	RETRO	4.8	21.0%	1.0	0.0	0.0	5.0	5.0	$0.22	$0.13	1.2
773	Retail	Efficient Air Compressors (VSD)	MO	23,741.6	20.8%	4,935.1	0.5	0.6	13.0	13.0	$3,367.84	$2,020.70	0.9
774	Retail	No Loss Condensate Drain	RETRO	476,153.6	0.4%	1,969.7	0.2	0.2	10.0	10.0	$244.00	$146.40	3.8
775	Retail	Efficient Air Nozzles	MO	1,129.7	50.0%	564.9	0.1	0.1	15.0	15.0	$57.00	$34.20	6.5
776	Retail	Air Conditioner - 17 IEER (5-20 Tons)	MO	626.3	14.1%	88.4	0.0	0.0	15.0	15.0	$153.28	$91.97	0.5
777	Retail	Air Conditioner - 18 IEER (5-20 Tons)	MO	626.3	18.9%	118.3	0.0	0.0	15.0	15.0	$214.59	$128.75	0.5
778	Retail	Air Conditioner - 21 IEER (5-20 Tons)	MO	626.3	30.5%	190.9	0.1	0.0	15.0	15.0	$398.52	$239.11	0.4
779	Retail	Air Conditioner - 14.3 IEER (20+ Tons)	MO	703.4	9.1%	63.9	0.0	0.0	15.0	15.0	$71.00	$42.60	0.8
780	Retail	Air Conditioner - 15 IEER (20+ Tons)	MO	703.4	13.3%	93.8	0.0	0.0	15.0	15.0	$109.23	$65.54	0.8
781	Retail	Air Conditioner - 17 IEER (20+ Tons)	MO	703.4	23.5%	165.5	0.1	0.0	15.0	15.0	$218.46	$131.08	0.7
782	Retail	Comprehensive Rooftop Unit Quality Maintenance (AC Tune-up)	RETRO	762.0	7.0%	53.4	0.0	0.0	3.0	3.0	$11.42	$6.85	1.1
783	Retail	Air Side Economizer	RETRO	626.3	20.0%	125.3	0.1	0.0	10.0	10.0	$126.67	$76.00	0.7
784	Retail	HVAC Occupancy Controls	RETRO	661.0	20.0%	132.2	0.1	0.0	15.0	15.0	$197.50	$118.50	0.6
785	Retail	Air Conditioner - 16 SEER (<5 Tons)	MO	653.2	12.5%	81.6	0.0	0.0	15.0	15.0	$115.00	$69.00	0.7
786	Retail	Air Conditioner - 18 SEER(<5 Tons)	MO	653.2	22.2%	145.2	0.1	0.0	15.0	15.0	$514.00	$308.40	0.3
787	Retail	Air Conditioner - 21 SEER (<5 Tons)	MO	653.2	33.3%	217.7	0.1	0.0	15.0	15.0	$630.50	$378.30	0.3
788	Retail	Smart Thermostat	RETRO	3,748.8	14.2%	530.8	0.2	0.0	11.0	11.0	$175.00	$105.00	2.2
789	Retail	PTAC - 7,000 to 15,000 Btuh	MO	842.8	14.6%	122.8	0.0	0.0	8.0	8.0	$84.00	$50.40	0.8
790	Retail	Air Cooled Chiller	MO	667.5	9.0%	60.1	0.0	0.0	23.0	23.0	$126.00	$75.60	0.6
791	Retail	Water Cooled Chiller	MO	335.3	22.7%	76.2	0.0	0.0	23.0	23.0	$61.00	$36.60	1.4
792	Retail	Window Film	RETRO	6,363.6	4.4%	280.0	0.1	0.0	10.0	10.0	$153.81	$92.29	1.2
793	Retail	Triple Pane Windows	MO	6,363.6	6.0%	381.8	0.2	0.0	25.0	25.0	$700.00	$420.00	0.6
794	Retail	Energy Recovery Ventilator	RETRO	703.4	4.9%	34.7	0.0	0.0	15.0	15.0	$1,500.00	$900.00	0.0
795	Retail	Heat Pump - 16 SEER (<5 Tons)	MO	1,895.5	7.2%	135.7	0.0	0.0	15.0	15.0	$135.00	$81.00	0.9
796	Retail	Heat Pump - 18 SEER(<5 Tons)	MO	1,895.5	13.7%	260.4	0.0	0.1	15.0	15.0	$445.76	$267.46	0.5
797	Retail	Heat Pump - 21 SEER(<5 Tons)	MO	1,895.5	19.4%	366.8	0.0	0.1	15.0	15.0	$520.06	$312.04	0.6
798	Retail	Heat Pump - 15.0 IEER COP 3.6 (65,000-134,000 Btu/hr)	MO	2,071.1	6.1%	126.8	0.0	0.0	15.0	15.0	$100.00	$60.00	1.1
799	Retail	Heat Pump - 16.0 IEER COP 3.8 (65,000-134,000 Btu/hr)	MO	2,071.1	11.4%	235.1	0.0	0.1	15.0	15.0	$171.08	$102.65	1.2
800	Retail	Heat Pump - 14.5 IEER COP 3.5 (135,000-239,000 Btu/hr)	MO	2,143.6	6.5%	140.1	0.0	0.0	15.0	15.0	$100.00	$60.00	1.2

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801	Retail	Heat Pump - 15.5 IEER COP 3.7 (135,000-239,000 Btu/hr)	MO	2,143.6	11.9%	255.0	0.0	0.1	15.0	15.0	$158.10	$94.86	1.4
802	Retail	Heat Pump - 12 IEER 3.4 COP (>239,000 Btu/hr)	MO	2,241.1	6.4%	143.9	0.0	0.0	15.0	15.0	$100.00	$60.00	1.3
803	Retail	Heat Pump - 13 IEER 3.6 COP (>239,000 Btu/hr)	MO	2,241.1	12.4%	277.2	0.0	0.1	15.0	15.0	$201.80	$121.08	1.2
804	Retail	Geothermal HP - 17 EER < 135kbtu	MO	2,145.2	42.9%	919.7	0.1	0.2	25.0	25.0	$4,361.00	$2,616.60	0.2
805	Retail	Geothermal HP - 19 EER < 135kbtu	MO	2,145.2	46.2%	991.8	0.1	0.2	25.0	25.0	$4,361.00	$2,616.60	0.2
806	Retail	PTHP - 7,000 to 15,000 Btuh	MO	4,238.5	16.7%	706.4	0.1	0.2	15.0	15.0	$84.00	$50.40	7.4
807	Retail	Heat Pump Water Heater	MO	16,398.4	73.3%	12,025.5	1.6	1.6	15.0	15.0	$1,797.00	$1,078.20	4.8
808	Retail	Low Flow Faucet Aerator	RETRO	288.3	32.2%	92.9	0.0	0.0	10.0	10.0	$8.00	$4.80	6.0
809	Retail	Pre-Rinse Spray Valves - DI	RETRO	18,058.7	54.2%	9,788.8	1.3	1.3	5.0	5.0	$54.00	$32.40	51.9
810	Retail	Ozone Commercial Laundry	MO	2,984.0	25.0%	746.0	0.1	0.1	10.0	10.0	$20,309.70	$12,185.82	0.0
811	Retail	Ext LED Replacing 100W MH (24/7)	RETRO	995.8	75.8%	754.8	0.0	0.1	10.0	10.0	$97.00	$58.20	2.8
812	Retail	Ext LED Replacing 175W MH (24/7)	RETRO	1,743.6	71.0%	1,238.6	0.0	0.1	10.0	10.0	$123.81	$74.29	3.6
813	Retail	Ext LED Replacing 250W MH (24/7)	RETRO	2,490.4	66.6%	1,658.5	0.0	0.2	10.0	10.0	$134.35	$80.61	4.4
814	Retail	Ext LED Replacing 400W MH (24/7)	RETRO	3,984.1	64.5%	2,570.2	0.0	0.3	10.0	10.0	$196.16	$117.70	4.7
815	Retail	Ext LED Replacing 1000W MH (24/7)	RETRO	9,467.3	70.4%	6,665.7	0.0	0.8	10.0	10.0	$319.31	$191.59	7.5
816	Retail	Ext LED Replacing 100W MH (D2D)	RETRO	488.8	75.8%	370.5	0.0	0.0	10.0	10.0	$97.00	$58.20	1.4
817	Retail	Ext LED Replacing 175W MH (D2D)	RETRO	855.9	71.0%	608.0	0.0	0.1	10.0	10.0	$123.81	$74.29	1.8
818	Retail	Ext LED Replacing 250W MH (D2D)	RETRO	1,222.5	66.6%	814.1	0.0	0.1	10.0	10.0	$134.35	$80.61	2.2
819	Retail	Ext LED Replacing 400W MH (D2D)	RETRO	1,955.7	64.5%	1,261.6	0.0	0.1	10.0	10.0	$196.16	$117.70	2.3
820	Retail	Ext LED Replacing 1000W MH (D2D)	RETRO	4,647.2	70.4%	3,272.0	0.0	0.4	10.0	10.0	$319.31	$191.59	3.7
821	Retail	LED Interior Direction (Track lighting / Wall-Wash Fixture)	RETRO	170.9	73.8%	126.0	0.0	0.0	15.0	15.0	$59.00	$35.40	1.3
822	Retail	LED Linear Replacement Lamps (Replacing T8)	RETRO	123.4	51.4%	63.4	0.0	0.0	10.0	10.0	$15.00	$9.00	1.9
823	Retail	LED Troffers (Replacing 1-Lamp T8)	RETRO	127.3	34.0%	43.3	0.0	0.0	15.0	15.0	$22.00	$13.20	1.2
824	Retail	LED Troffers (Replacing 2-Lamp T8)	RETRO	249.4	51.4%	128.2	0.0	0.0	15.0	15.0	$61.00	$36.60	1.3
825	Retail	LED Troffers (Replacing 3-Lamp T8)	RETRO	369.7	54.0%	199.8	0.0	0.0	15.0	15.0	$76.00	$45.60	1.7
826	Retail	LED Troffers (Replacing 4-Lamp T8)	RETRO	492.7	54.3%	267.3	0.0	0.0	15.0	15.0	$104.00	$62.40	1.6
827	Retail	LED Linear Ambient Fixture (<6000 lumens, replacing T8)	RETRO	248.8	50.3%	125.1	0.0	0.0	15.0	15.0	$46.67	$28.00	1.7
828	Retail	LED Linear Ambient Fixture (>6000 lumens, replacing T5HO)	RETRO	656.3	53.2%	348.9	0.0	0.0	15.0	15.0	$152.00	$91.20	1.4
829	Retail	LED Low-Bay Fixture	RETRO	686.9	67.0%	460.3	0.0	0.0	15.0	15.0	$42.88	$25.73	6.8
830	Retail	LED High-Bay Fixture (Replacing T8 High Bay)	RETRO	1,286.4	57.0%	733.5	0.1	0.1	15.0	15.0	$48.07	$28.84	9.6
831	Retail	LED High-Bay Fixture (Replacing Metal Halide)	RETRO	5,162.9	72.3%	3,733.0	0.4	0.4	15.0	15.0	$187.94	$112.76	12.5
832	Retail	Fluorescent Delamping	RETRO	109.8	100.0%	109.8	0.0	0.0	11.0	11.0	$18.50	$11.10	2.9
833	Retail	Lighting Occupancy Sensor	RETRO	570.5	30.0%	171.2	0.0	0.0	15.0	15.0	$65.40	$39.24	1.6
834	Retail	Lighting Daylight Sensor	RETRO	730.7	28.0%	204.6	0.0	0.0	15.0	15.0	$57.50	$34.50	2.2
835	Retail	Dual Occupancy / Daylight Sensor	RETRO	326.0	38.0%	123.9	0.0	0.0	15.0	15.0	$75.00	$45.00	1.0
836	Retail	Luminaire-Level Lighting Controls	RETRO	326.0	61.0%	198.8	0.0	0.0	15.0	15.0	$56.00	$33.60	2.2
837	Retail	Networked Lighting Control	RETRO	2.7	35.0%	0.9	0.0	0.0	15.0	15.0	$0.55	$0.33	1.1
838	Retail	LED Exit Sign	RETRO	65.5	71.4%	46.8	0.0	0.0	5.0	5.0	$32.50	$19.50	0.4
839	Retail	Non-Refrigerated Vending Machine Controls	RETRO	385.4	61.4%	236.8	0.0	0.0	5.0	5.0	$233.00	$139.80	0.3
840	Retail	Kitchen Exhaust Hood Demand Ventilation Control System	MO	0.0	0.0%	0.0	0.0	0.0	20.0	20.0	$1.73	$1.04	0.0
841	Retail	High Efficiency Hand Dryers	MO	1,909.5	83.0%	1,585.2	0.2	0.2	10.0	10.0	$483.00	$289.80	1.6
842	Retail	ENERGY STAR Uninterrupted Power Supply	RETRO	3,125.1	3.7%	114.4	0.0	0.0	15.0	15.0	$59.00	$35.40	1.3
843	Retail	Miscellaneous Custom	RETRO	6.7	15.0%	1.0	0.0	0.0	10.0	10.0	$0.40	$0.24	1.2
844	Retail	Pump and Fan Variable Frequency Drive Controls (Pumps)	MO	1,675.3	27.7%	464.6	0.1	0.1	15.0	15.0	$198.32	$118.99	1.8
845	Retail	Power Drive Systems	RETRO	4.3	23.0%	1.0	0.0	0.0	15.0	15.0	$0.13	$0.08	6.0
846	Retail	Switch Reluctance Motors	MO	28,430.4	30.6%	8,699.7	1.3	1.3	15.0	15.0	$527.50	$316.50	12.9
847	Retail	Energy Star Printer/Copier/Fax	MO	418.0	26.3%	110.0	0.0	0.0	6.0	6.0	$0.00	$0.00	0.0
848	Retail	Advanced Power Strip – Teri 1 Commercial Use	RETRO	188.2	57.7%	108.6	0.0	0.0	7.0	7.0	$10.00	$6.00	3.8
849	Retail	Smart Socket	RETRO	79.9	60.6%	48.4	0.0	0.0	7.0	7.0	$9.00	$5.40	1.9
850	Retail	Energy Star Server	MO	2,166.7	30.0%	650.0	0.1	0.1	9.0	9.0	$300.95	$180.57	0.9

Big Rivers — **Measure Assumption Tab**

Measure #	Building Type	Measure Name	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW	RC EUL	EE EUL	Measure Cost	Incentive Amount	TRC
851	Retail	Server Virtualization	RETRO	2,166.7	13.9%	301.1	0.0	0.0	9.0	9.0	$26.97	$16.18	4.9
852	Retail	Electrically Commutated Plug Fans in data centers	RETRO	86,783.0	18.2%	15,778.0	1.7	1.8	15.0	15.0	$480.00	$288.00	21.4
853	Retail	Computer Room Air Conditioner Economizer	RETRO	764.0	46.9%	358.0	0.0	0.0	15.0	15.0	$82.00	$49.20	2.8
854	Retail	High Efficiency CRAC unit	MO	8,940.1	25.3%	2,264.8	0.2	0.3	20.0	20.0	$750.00	$450.00	2.4
855	Retail	Data Center Hot/Cold Aisle Configuration	RETRO	13.3	7.5%	1.0	0.0	0.0	10.0	10.0	$0.23	$0.14	2.1
856	Retail	Strip Curtains	RETRO	0.0	0.0%	0.0	0.0	0.0	4.0	4.0	$10.22	$6.13	0.0
857	Retail	Floating Head Pressure Controls	RETRO	1,228.0	25.0%	307.0	0.0	0.0	15.0	15.0	$431.00	$258.60	0.5
858	Retail	Electronically Commutated (EC) Walk-In Evaporator Fan Motor	RETRO	2,883.6	55.0%	1,586.0	0.2	0.2	15.0	15.0	$305.00	$183.00	3.6
859	Retail	Evaporator Fan Motor Controls	RETRO	1,297.6	22.6%	293.0	0.0	0.0	13.0	13.0	$161.75	$97.05	1.1
860	Retail	Variable Speed Condenser Fan	RETRO	3,157.9	47.5%	1,500.0	0.2	0.2	15.0	15.0	$1,170.00	$702.00	0.9
861	Retail	Door Heater Controls for Cooler	RETRO	578.6	41.5%	240.1	0.0	0.0	10.0	10.0	$79.50	$47.70	1.5
862	Retail	Automated Door Closer for Refrigerator	RETRO	1,259,892.8	0.2%	2,398.7	0.3	0.3	8.0	8.0	$502.00	$301.20	2.0
863	Retail	Aerofoils for Open Display Cases	RETRO	45,880.0	10.0%	4,588.0	0.6	0.5	10.0	10.0	$311.54	$186.92	7.4
864	Retail	Display Case Door Retrofit, Medium Temp	RETRO	1,558.3	50.0%	779.1	0.1	0.1	15.0	15.0	$390.00	$234.00	1.4
865	Retail	Electronically Commutated (EC) Reach-In Evaporator Fan Motor	RETRO	2,883.6	55.0%	1,586.0	0.2	0.2	15.0	15.0	$305.00	$183.00	3.6
866	Retail	Q-Sync Motor for Walk-In and Reach-in Evaporator Fan Motor	RETRO	2,090.6	24.1%	504.6	0.1	0.1	10.0	10.0	$96.00	$57.60	2.7
867	Retail	Night Covers for Coolers	RETRO	1,510.5	9.0%	136.0	0.0	0.0	5.0	5.0	$42.00	$25.20	0.9
868	Retail	Door Heater Controls for Freezer	RETRO	2,016.2	32.5%	655.3	0.1	0.1	10.0	10.0	$79.50	$47.70	4.2
869	Retail	Automated Door Closer for Freezer	RETRO	1,259,892.8	0.6%	6,948.8	1.0	0.8	8.0	8.0	$502.00	$301.20	5.8
870	Retail	Night Covers for Freezers	RETRO	2,349.3	9.0%	211.3	0.0	0.0	5.0	5.0	$42.00	$25.20	1.4
871	Retail	Refrigeration - Custom	RETRO	6.7	15.0%	1.0	0.0	0.0	10.0	10.0	$0.40	$0.24	1.3
872	Retail	Retro-commissioning_Refrigerator Optimization	RETRO	4.8	21.0%	1.0	0.0	0.0	5.0	5.0	$0.22	$0.13	1.3
873	Retail	ESTAR Refrigerated Vending Machine	MO	1,277.5	12.0%	153.3	0.0	0.0	14.0	14.0	$500.00	$300.00	0.2
874	Retail	Refrigerated Vending Machine Controls	RETRO	1,662.9	23.5%	390.1	0.1	0.0	5.0	5.0	$245.00	$147.00	0.4
875	Retail	Commercial Ice Marker	MO	5,550.9	7.9%	440.3	0.1	0.0	9.0	9.0	$222.00	$133.20	0.9
876	Retail	LED Refrigerated Display Case Lighting Average 6W/LF	MO	114.6	73.7%	84.5	0.0	0.0	9.0	9.0	$11.00	$6.60	3.5
877	Retail	Pump and Fan Variable Frequency Drive Controls (Fans)	RETRO	13,400.3	59.0%	7,905.2	1.2	1.1	15.0	15.0	$2,250.00	$1,350.00	2.7
878	Retail	Cogged V-Belt (Synchronous)	RETRO	14,669.9	3.1%	454.8	0.1	0.1	15.0	15.0	$381.00	$228.60	0.8
879	Retail	HVAC - Energy Management System	RETRO	12.5	8.0%	1.0	0.0	0.0	15.0	15.0	$0.40	$0.24	1.8
880	Retail	GREM Controls	RETRO	0.0	0.0%	0.0	0.0	0.0	15.0	15.0	$0.00	$0.00	0.0
881	Retail	Demand Control Ventilation	RETRO	1,662.5	20.0%	332.5	0.1	0.0	10.0	10.0	$235.60	$141.36	0.7
882	Retail	High Efficiency DOAS	RETRO	5.2	35.7%	1.9	0.0	0.0	15.0	15.0	$15.22	$9.13	0.1
883	Retail	Advanced Rooftop Controls	RETRO	775.7	90.8%	704.7	0.1	0.1	10.0	10.0	$341.21	$204.72	1.1
884	Retail	Retro-commissioning_Bld Optimization	RETRO	12.5	8.0%	1.0	0.0	0.0	15.0	15.0	$0.12	$0.07	5.9
885	Retail	Commercial Weatherstripping	RETRO	222.3	2.0%	4.4	0.0	0.0	10.0	10.0	$8.00	$4.80	0.3
886	Retail	WholeBlg - Com RET	RETRO	6.7	15.0%	1.0	0.0	0.0	15.0	15.0	$0.40	$0.24	1.8
887	Retail	Strategic Energy Management	RETRO	0.0	0.0%	0.0	0.0	0.0	5.0	5.0	$0.27	$0.16	0.6
888	Retail	Power Distribution Equipment Upgrades (Transformers)	RETRO	990.2	0.6%	5.5	0.0	0.0	30.0	30.0	$6.27	$3.76	0.8
889	Retail	WholeBlg - Com NC	NC	4.0	25.0%	1.0	0.0	0.0	15.0	15.0	$0.40	$0.24	1.8
890	Office	Commercial Combination Oven (Electric)	MO	19,496.1	38.6%	7,532.5	3.8	0.9	12.0	12.0	$2,270.00	$1,362.00	3.6
891	Office	Commercial Electric Convection Oven	MO	10,863.7	19.0%	2,064.2	1.0	0.3	12.0	12.0	$960.00	$576.00	2.3
892	Office	Commercial Electric Griddle	MO	17,056.0	15.2%	2,596.0	1.3	0.3	12.0	12.0	$0.00	$0.00	0.0
893	Office	Commercial Electric Steam Cooker	MO	16,914.5	79.9%	13,506.7	6.9	1.7	12.0	12.0	$2,757.00	$1,654.20	5.2
894	Office	Dishwasher Low Temp Door (Energy Star)	MO	35,655.0	44.2%	15,765.8	8.0	2.0	16.0	16.0	$466.50	$279.90	45.4
895	Office	Dishwasher High Temp Door (Energy Star)	MO	38,282.0	16.4%	6,278.8	3.2	0.8	15.0	15.0	$1,550.00	$930.00	5.2
896	Office	Energy efficient electric fryer	MO	18,955.0	17.3%	3,274.0	1.7	0.4	12.0	12.0	$1,500.00	$900.00	2.3
897	Office	Insulated Holding Cabinets	MO	1,478.3	36.9%	545.3	0.3	0.1	12.0	12.0	$1,000.00	$600.00	0.6
898	Office	Compressed Air Leak Repair	RETRO	5.9	17.0%	1.0	0.0	0.0	3.0	3.0	$0.08	$0.05	2.3
899	Office	Retro-commissioning_Compressed Air Optimization	RETRO	4.8	21.0%	1.0	0.0	0.0	5.0	5.0	$0.22	$0.13	1.3
900	Office	Efficient Air Compressors (VSD)	MO	23,741.6	20.8%	4,935.1	0.7	0.6	13.0	13.0	$3,367.84	$2,020.70	0.9

Big Rivers | **Measure Assumption Tab**

Measure #	Building Type	Measure Name	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW	RC EUL	EE EUL	Measure Cost	Incentive Amount	TRC
901	Office	No Loss Condensate Drain	RETRO	476,153.6	0.4%	1,969.7	0.3	0.2	10.0	10.0	$244.00	$146.40	4.2
902	Office	Efficient Air Nozzles	MO	1,129.7	50.0%	564.9	0.1	0.1	15.0	15.0	$57.00	$34.20	7.1
903	Office	Air Conditioner - 17 IEER (5-20 Tons)	MO	1,885.5	14.1%	266.2	0.2	0.0	15.0	15.0	$153.28	$91.97	2.0
904	Office	Air Conditioner - 18 IEER (5-20 Tons)	MO	1,885.5	18.9%	356.1	0.2	0.0	15.0	15.0	$214.59	$128.75	1.9
905	Office	Air Conditioner - 21 IEER (5-20 Tons)	MO	1,885.5	30.5%	574.6	0.3	0.0	15.0	15.0	$398.52	$239.11	1.7
906	Office	Air Conditioner - 14.3 IEER (20+ Tons)	MO	2,117.5	9.1%	192.5	0.1	0.0	15.0	15.0	$71.00	$42.60	3.1
907	Office	Air Conditioner - 15 IEER (20+ Tons)	MO	2,117.5	13.3%	282.3	0.2	0.0	15.0	15.0	$109.23	$65.54	3.0
908	Office	Air Conditioner - 17 IEER (20+ Tons)	MO	2,117.5	23.5%	498.2	0.3	0.0	15.0	15.0	$218.46	$131.08	2.6
909	Office	Comprehensive Rooftop Unit Quality Maintenance (AC Tune-up)	RETRO	2,294.0	7.0%	160.6	0.1	0.0	3.0	3.0	$11.42	$6.85	4.0
910	Office	Air Side Economizer	RETRO	1,885.5	20.0%	377.1	0.2	0.0	10.0	10.0	$126.67	$76.00	2.5
911	Office	HVAC Occupancy Controls	RETRO	1,989.8	20.0%	398.0	0.2	0.0	15.0	15.0	$197.50	$118.50	2.3
912	Office	Air Conditioner - 16 SEER (<5 Tons)	MO	1,966.3	12.5%	245.8	0.1	0.0	15.0	15.0	$115.00	$69.00	2.5
913	Office	Air Conditioner - 18 SEER(<5 Tons)	MO	1,966.3	22.2%	437.0	0.2	0.0	15.0	15.0	$514.00	$308.40	1.0
914	Office	Air Conditioner - 21 SEER (<5 Tons)	MO	1,966.3	33.3%	655.4	0.4	0.0	15.0	15.0	$630.50	$378.30	1.2
915	Office	Smart Thermostat	RETRO	11,285.0	14.2%	1,598.0	0.9	0.0	11.0	11.0	$175.00	$105.00	8.3
916	Office	PTAC - 7,000 to 15,000 Btuh	MO	2,537.2	14.6%	369.6	0.2	0.0	8.0	8.0	$84.00	$50.40	3.0
917	Office	Air Cooled Chiller	MO	2,009.4	9.0%	181.0	0.1	0.0	23.0	23.0	$126.00	$75.60	2.1
918	Office	Water Cooled Chiller	MO	1,009.4	22.7%	229.4	0.1	0.0	23.0	23.0	$61.00	$36.60	5.4
919	Office	Window Film	RETRO	6,363.6	4.4%	280.0	0.2	0.0	10.0	10.0	$153.81	$92.29	1.5
920	Office	Triple Pane Windows	MO	6,363.6	6.0%	381.8	0.2	0.0	25.0	25.0	$700.00	$420.00	0.8
921	Office	Energy Recovery Ventilator	RETRO	2,117.5	15.5%	327.3	0.2	0.0	15.0	15.0	$1,500.00	$900.00	0.3
922	Office	Heat Pump - 16 SEER (<5 Tons)	MO	4,429.1	8.0%	352.9	0.1	0.1	15.0	15.0	$135.00	$81.00	2.5
923	Office	Heat Pump - 18 SEER(<5 Tons)	MO	4,429.1	15.0%	665.5	0.1	0.2	15.0	15.0	$445.76	$267.46	1.4
924	Office	Heat Pump - 21 SEER(<5 Tons)	MO	4,429.1	21.5%	951.0	0.2	0.2	15.0	15.0	$520.06	$312.04	1.8
925	Office	Heat Pump - 15.0 IEER COP 3.6 (65,000-134,000 Btu/hr)	MO	4,781.9	6.3%	300.9	0.1	0.1	15.0	15.0	$100.00	$60.00	2.9
926	Office	Heat Pump - 16.0 IEER COP 3.8 (65,000-134,000 Btu/hr)	MO	4,781.9	11.6%	554.8	0.1	0.1	15.0	15.0	$171.08	$102.65	3.1
927	Office	Heat Pump - 14.5 IEER COP 3.5 (135,000-239,000 Btu/hr)	MO	4,956.2	6.8%	336.2	0.1	0.1	15.0	15.0	$100.00	$60.00	3.3
928	Office	Heat Pump - 15.5 IEER COP 3.7 (135,000-239,000 Btu/hr)	MO	4,956.2	12.2%	605.8	0.1	0.1	15.0	15.0	$158.10	$94.86	3.7
929	Office	Heat Pump - 12 IEER 3.4 COP (>239,000 Btu/hr)	MO	5,206.9	6.8%	353.2	0.1	0.1	15.0	15.0	$100.00	$60.00	3.4
930	Office	Heat Pump - 13 IEER 3.6 COP (>239,000 Btu/hr)	MO	5,206.9	12.8%	665.4	0.1	0.2	15.0	15.0	$201.80	$121.08	3.2
931	Office	Geothermal HP - 17 EER < 135kbtu	MO	4,959.5	39.4%	1,956.2	0.4	0.4	25.0	25.0	$4,361.00	$2,616.60	0.5
932	Office	Geothermal HP - 19 EER < 135kbtu	MO	4,959.5	43.0%	2,132.8	0.4	0.5	25.0	25.0	$4,361.00	$2,616.60	0.6
933	Office	PTHP - 7,000 to 15,000 Btuh	MO	9,166.6	16.7%	1,527.8	0.3	0.3	15.0	15.0	$84.00	$50.40	17.6
934	Office	Heat Pump Water Heater	MO	15,870.4	73.3%	11,638.3	2.0	1.7	15.0	15.0	$1,797.00	$1,078.20	5.2
935	Office	Low Flow Faucet Aerator	RETRO	427.8	32.4%	138.5	0.0	0.0	10.0	10.0	$8.00	$4.80	10.1
936	Office	Pre-Rinse Spray Valves - DI	RETRO	18,058.7	54.2%	9,788.8	1.6	1.5	5.0	5.0	$54.00	$32.40	58.2
937	Office	Ozone Commercial Laundry	MO	2,984.0	25.0%	746.0	0.1	0.1	10.0	10.0	$20,309.70	$12,185.82	0.0
938	Office	Ext LED Replacing 100W MH (24/7)	RETRO	995.8	75.8%	754.8	0.0	0.1	10.0	10.0	$97.00	$58.20	2.8
939	Office	Ext LED Replacing 175W MH (24/7)	RETRO	1,743.6	71.0%	1,238.6	0.0	0.1	10.0	10.0	$123.81	$74.29	3.6
940	Office	Ext LED Replacing 250W MH (24/7)	RETRO	2,490.4	66.6%	1,658.5	0.0	0.2	10.0	10.0	$134.35	$80.61	4.5
941	Office	Ext LED Replacing 400W MH (24/7)	RETRO	3,984.1	64.5%	2,570.2	0.0	0.3	10.0	10.0	$196.16	$117.70	4.7
942	Office	Ext LED Replacing 1000W MH (24/7)	RETRO	9,467.3	70.4%	6,665.7	0.0	0.8	10.0	10.0	$319.31	$191.59	7.5
943	Office	Ext LED Replacing 100W MH (D2D)	RETRO	488.8	75.8%	370.5	0.0	0.0	10.0	10.0	$97.00	$58.20	1.4
944	Office	Ext LED Replacing 175W MH (D2D)	RETRO	855.9	71.0%	608.0	0.0	0.1	10.0	10.0	$123.81	$74.29	1.8
945	Office	Ext LED Replacing 250W MH (D2D)	RETRO	1,222.5	66.6%	814.1	0.0	0.1	10.0	10.0	$134.35	$80.61	2.2
946	Office	Ext LED Replacing 400W MH (D2D)	RETRO	1,955.7	64.5%	1,261.6	0.0	0.1	10.0	10.0	$196.16	$117.70	2.3
947	Office	Ext LED Replacing 1000W MH (D2D)	RETRO	4,647.2	70.4%	3,272.0	0.0	0.4	10.0	10.0	$319.31	$191.59	3.7
948	Office	LED Interior Direction (Track lighting / Wall-Wash Fixture)	RETRO	125.6	73.8%	92.6	0.0	0.0	15.0	15.0	$59.00	$35.40	1.2
949	Office	LED Linear Replacement Lamps (Replacing T8)	RETRO	90.7	51.4%	46.6	0.0	0.0	10.0	10.0	$15.00	$9.00	1.8
950	Office	LED Troffers (Replacing 1-Lamp T8)	RETRO	93.6	34.0%	31.8	0.0	0.0	15.0	15.0	$22.00	$13.20	1.1

Big Rivers | **Measure Assumption Tab**

Measure #	Building Type	Measure Name	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW	RC EUL	EE EUL	Measure Cost	Incentive Amount	TRC
951	Office	LED Troffers (Replacing 2-Lamp T8)	RETRO	183.3	51.4%	94.2	0.0	0.0	15.0	15.0	$61.00	$36.60	1.2
952	Office	LED Troffers (Replacing 3-Lamp T8)	RETRO	271.8	54.0%	146.9	0.0	0.0	15.0	15.0	$76.00	$45.60	1.5
953	Office	LED Troffers (Replacing 4-Lamp T8)	RETRO	362.1	54.3%	196.5	0.0	0.0	15.0	15.0	$104.00	$62.40	1.5
954	Office	LED Linear Ambient Fixture (<6000 lumens, replacing T8)	RETRO	182.9	50.3%	92.0	0.0	0.0	15.0	15.0	$46.67	$28.00	1.6
955	Office	LED Linear Ambient Fixture (>6000 lumens, replacing T5HO)	RETRO	482.4	53.2%	256.5	0.0	0.0	15.0	15.0	$152.00	$91.20	1.3
956	Office	LED Low-Bay Fixture	RETRO	504.9	67.0%	338.3	0.1	0.0	15.0	15.0	$42.88	$25.73	6.3
957	Office	LED High-Bay Fixture (Replacing T8 High Bay)	RETRO	945.6	57.0%	539.1	0.1	0.1	15.0	15.0	$48.07	$28.84	8.9
958	Office	LED High-Bay Fixture (Replacing Metal Halide)	RETRO	3,795.1	72.3%	2,744.0	0.5	0.4	15.0	15.0	$187.94	$112.76	11.6
959	Office	Fluorescent Delamping	RETRO	80.7	100.0%	80.7	0.0	0.0	11.0	11.0	$18.50	$11.10	2.7
960	Office	Lighting Occupancy Sensor	RETRO	419.4	30.0%	125.8	0.0	0.0	15.0	15.0	$65.40	$39.24	1.5
961	Office	Lighting Daylight Sensor	RETRO	537.1	28.0%	150.4	0.0	0.0	15.0	15.0	$57.50	$34.50	2.1
962	Office	Dual Occupancy / Daylight Sensor	RETRO	239.6	38.0%	91.1	0.0	0.0	15.0	15.0	$75.00	$45.00	1.0
963	Office	Luminaire-Level Lighting Controls	RETRO	239.6	61.0%	146.2	0.0	0.0	15.0	15.0	$56.00	$33.60	2.1
964	Office	Networked Lighting Control	RETRO	2.0	35.0%	0.7	0.0	0.0	15.0	15.0	$0.41	$0.24	1.3
965	Office	LED Exit Sign	RETRO	67.1	71.4%	47.9	0.0	0.0	5.0	5.0	$32.50	$19.50	0.5
966	Office	Non-Refrigerated Vending Machine Controls	RETRO	385.4	61.4%	236.8	0.0	0.0	5.0	5.0	$233.00	$139.80	0.3
967	Office	Kitchen Exhaust Hood Demand Ventilation Control System	MO	0.0	0.0%	0.0	0.0	0.0	20.0	20.0	$1.73	$1.04	0.0
968	Office	High Efficiency Hand Dryers	MO	261.6	83.0%	217.2	0.0	0.0	10.0	10.0	$483.00	$289.80	0.2
969	Office	ENERGY STAR Uninterrupted Power Supply	RETRO	3,125.1	3.7%	114.4	0.0	0.0	15.0	15.0	$59.00	$35.40	1.4
970	Office	Miscellaneous Custom	RETRO	6.7	15.0%	1.0	0.0	0.0	10.0	10.0	$0.40	$0.24	1.3
971	Office	Pump and Fan Variable Frequency Drive Controls (Pumps)	MO	3,090.2	27.7%	857.0	0.1	0.1	15.0	15.0	$198.32	$118.99	3.1
972	Office	Power Drive Systems	RETRO	4.3	23.0%	1.0	0.0	0.0	15.0	15.0	$0.13	$0.08	5.6
973	Office	Switch Reluctance Motors	MO	17,620.4	30.6%	5,391.8	0.8	0.7	15.0	15.0	$527.50	$316.50	7.4
974	Office	Energy Star Printer/Copier/Fax	MO	418.0	26.3%	110.0	0.0	0.0	6.0	6.0	$0.00	$0.00	0.0
975	Office	Advanced Power Strip – Teri 1 Commercial Use	RETRO	188.2	57.7%	108.6	0.0	0.0	7.0	7.0	$10.00	$6.00	4.2
976	Office	Smart Socket	RETRO	79.9	60.6%	48.4	0.0	0.0	7.0	7.0	$9.00	$5.40	2.1
977	Office	Energy Star Server	MO	2,166.7	30.0%	650.0	0.1	0.1	9.0	9.0	$300.95	$180.57	1.0
978	Office	Server Virtualization	RETRO	2,166.7	13.9%	301.1	0.0	0.0	9.0	9.0	$26.97	$16.18	5.3
979	Office	Electrically Commutated Plug Fans in data centers	RETRO	86,783.0	18.2%	15,778.0	2.3	1.8	15.0	15.0	$480.00	$288.00	23.4
980	Office	Computer Room Air Conditioner Economizer	RETRO	764.0	46.9%	358.0	0.1	0.0	15.0	15.0	$82.00	$49.20	3.1
981	Office	High Efficiency CRAC unit	MO	8,940.1	25.3%	2,264.8	0.3	0.3	20.0	20.0	$750.00	$450.00	2.7
982	Office	Data Center Hot/Cold Aisle Configuration	RETRO	13.3	7.5%	1.0	0.0	0.0	10.0	10.0	$0.23	$0.14	2.3
983	Office	Strip Curtains	RETRO	0.0	0.0%	0.0	0.0	0.0	4.0	4.0	$10.22	$6.13	0.0
984	Office	Floating Head Pressure Controls	RETRO	1,228.0	25.0%	307.0	0.0	0.0	15.0	15.0	$431.00	$258.60	0.5
985	Office	Electronically Commutated (EC) Walk-In Evaporator Fan Motor	RETRO	2,883.6	55.0%	1,586.0	0.2	0.2	15.0	15.0	$305.00	$183.00	3.6
986	Office	Evaporator Fan Motor Controls	RETRO	1,297.6	22.6%	293.0	0.0	0.0	13.0	13.0	$161.75	$97.05	1.1
987	Office	Variable Speed Condenser Fan	RETRO	3,157.9	47.5%	1,500.0	0.2	0.2	15.0	15.0	$1,170.00	$702.00	0.9
988	Office	Door Heater Controls for Cooler	RETRO	578.6	41.5%	240.1	0.0	0.0	10.0	10.0	$79.50	$47.70	1.5
989	Office	Automated Door Closer for Refrigerator	RETRO	1,259,892.8	0.2%	2,398.7	0.3	0.3	8.0	8.0	$502.00	$301.20	2.0
990	Office	Aerofoils for Open Display Cases	RETRO	45,880.0	10.0%	4,588.0	0.6	0.5	10.0	10.0	$311.54	$186.92	7.4
991	Office	Display Case Door Retrofit, Medium Temp	RETRO	1,558.3	50.0%	779.1	0.1	0.1	15.0	15.0	$390.00	$234.00	1.4
992	Office	Electronically Commutated (EC) Reach-In Evaporator Fan Motor	RETRO	2,883.6	55.0%	1,586.0	0.2	0.2	15.0	15.0	$305.00	$183.00	3.6
993	Office	Q-Sync Motor for Walk-In and Reach-in Evaporator Fan Motor	RETRO	2,090.6	24.1%	504.6	0.1	0.1	10.0	10.0	$96.00	$57.60	2.7
994	Office	Night Covers for Coolers	RETRO	1,510.5	9.0%	136.0	0.0	0.0	5.0	5.0	$42.00	$25.20	0.9
995	Office	Door Heater Controls for Freezer	RETRO	2,016.2	32.5%	655.3	0.1	0.1	10.0	10.0	$79.50	$47.70	4.2
996	Office	Automated Door Closer for Freezer	RETRO	1,259,892.8	0.6%	6,948.8	1.0	0.8	8.0	8.0	$502.00	$301.20	5.8
997	Office	Night Covers for Freezers	RETRO	2,349.3	9.0%	211.3	0.0	0.0	5.0	5.0	$42.00	$25.20	1.4
998	Office	Refrigeration - Custom	RETRO	6.7	15.0%	1.0	0.0	0.0	10.0	10.0	$0.40	$0.24	1.3
999	Office	Retro-commissioning_Refrigerator Optimization	RETRO	4.8	21.0%	1.0	0.0	0.0	5.0	5.0	$0.22	$0.13	1.3
1000	Office	ESTAR Refrigerated Vending Machine	MO	1,277.5	12.0%	153.3	0.0	0.0	14.0	14.0	$500.00	$300.00	0.2

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Measure #	Building Type	Measure Name	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW	RC EUL	EE EUL	Measure Cost	Incentive Amount	TRC
1001	Office	Refrigerated Vending Machine Controls	RETRO	1,662.9	23.5%	390.1	0.1	0.0	5.0	5.0	$245.00	$147.00	0.4
1002	Office	Commercial Ice Marker	MO	5,550.9	7.9%	440.3	0.1	0.0	9.0	9.0	$222.00	$133.20	0.9
1003	Office	LED Refrigerated Display Case Lighting Average 6W/LF	MO	114.6	73.7%	84.5	0.0	0.0	9.0	9.0	$11.00	$6.60	3.5
1004	Office	Pump and Fan Variable Frequency Drive Controls (Fans)	RETRO	6,785.8	59.0%	4,003.1	0.8	0.6	15.0	15.0	$2,250.00	$1,350.00	1.5
1005	Office	Cogged V-Belt (Synchronous)	RETRO	9,092.0	3.1%	281.9	0.0	0.0	15.0	15.0	$381.00	$228.60	0.6
1006	Office	HVAC - Energy Management System	RETRO	12.5	8.0%	1.0	0.0	0.0	15.0	15.0	$0.40	$0.24	2.0
1007	Office	GREM Controls	RETRO	0.0	0.0%	0.0	0.0	0.0	15.0	15.0	$0.00	$0.00	0.0
1008	Office	Demand Control Ventilation	RETRO	1,313.3	20.0%	262.7	0.1	0.0	10.0	10.0	$235.60	$141.36	0.7
1009	Office	High Efficiency DOAS	RETRO	5.2	35.7%	1.9	0.0	0.0	15.0	15.0	$15.22	$9.13	0.1
1010	Office	Advanced Rooftop Controls	RETRO	2,169.5	49.6%	1,076.5	0.2	0.1	10.0	10.0	$341.21	$204.72	1.9
1011	Office	Retro-commissioning_Bld Optimization	RETRO	12.5	8.0%	1.0	0.0	0.0	15.0	15.0	$0.12	$0.07	6.8
1012	Office	Commercial Weatherstripping	RETRO	222.3	2.0%	4.4	0.0	0.0	10.0	10.0	$8.00	$4.80	0.3
1013	Office	WholeBlg - Com RET	RETRO	6.7	15.0%	1.0	0.0	0.0	15.0	15.0	$0.40	$0.24	2.0
1014	Office	Strategic Energy Management	RETRO	33.3	3.0%	1.0	0.0	0.0	5.0	5.0	$0.27	$0.16	1.2
1015	Office	Power Distribution Equipment Upgrades (Transformers)	RETRO	990.2	0.6%	5.5	0.0	0.0	30.0	30.0	$6.27	$3.76	0.9
1016	Office	WholeBlg - Com NC	NC	4.0	25.0%	1.0	0.0	0.0	15.0	15.0	$0.40	$0.24	2.0
1017	Warehouse	Commercial Combination Oven (Electric)	MO	19,496.1	38.6%	7,532.5	1.8	0.8	12.0	12.0	$2,270.00	$1,362.00	2.4
1018	Warehouse	Commercial Electric Convection Oven	MO	10,863.7	19.0%	2,064.2	0.5	0.2	12.0	12.0	$960.00	$576.00	1.5
1019	Warehouse	Commercial Electric Griddle	MO	17,056.0	15.2%	2,596.0	0.6	0.3	12.0	12.0	$0.00	$0.00	0.0
1020	Warehouse	Commercial Electric Steam Cooker	MO	16,914.5	79.9%	13,506.7	3.3	1.4	12.0	12.0	$2,757.00	$1,654.20	3.5
1021	Warehouse	Dishwasher Low Temp Door (Energy Star)	MO	35,655.0	44.2%	15,765.8	3.9	1.7	16.0	16.0	$466.50	$279.90	30.0
1022	Warehouse	Dishwasher High Temp Door (Energy Star)	MO	38,282.0	16.4%	6,278.8	1.5	0.7	15.0	15.0	$1,550.00	$930.00	3.4
1023	Warehouse	Energy efficient electric fryer	MO	18,955.0	17.3%	3,274.0	0.8	0.3	12.0	12.0	$1,500.00	$900.00	1.6
1024	Warehouse	Insulated Holding Cabinets	MO	1,478.3	36.9%	545.3	0.1	0.1	12.0	12.0	$1,000.00	$600.00	0.4
1025	Warehouse	Compressed Air Leak Repair	RETRO	5.9	17.0%	1.0	0.0	0.0	3.0	3.0	$0.08	$0.05	2.2
1026	Warehouse	Retro-commissioning_Compressed Air Optimization	RETRO	4.8	21.0%	1.0	0.0	0.0	5.0	5.0	$0.22	$0.13	1.3
1027	Warehouse	Efficient Air Compressors (VSD)	MO	23,741.6	20.8%	4,935.1	0.7	0.5	13.0	13.0	$3,367.84	$2,020.70	0.9
1028	Warehouse	No Loss Condensate Drain	RETRO	476,153.6	0.4%	1,969.7	0.3	0.2	10.0	10.0	$244.00	$146.40	4.0
1029	Warehouse	Efficient Air Nozzles	MO	1,129.7	50.0%	564.9	0.1	0.1	15.0	15.0	$57.00	$34.20	6.8
1030	Warehouse	Air Conditioner - 17 IEER (5-20 Tons)	MO	293.4	14.1%	41.4	0.0	0.0	15.0	15.0	$153.28	$91.97	0.3
1031	Warehouse	Air Conditioner - 18 IEER (5-20 Tons)	MO	293.4	18.9%	55.4	0.0	0.0	15.0	15.0	$214.59	$128.75	0.3
1032	Warehouse	Air Conditioner - 21 IEER (5-20 Tons)	MO	293.4	30.5%	89.4	0.1	0.0	15.0	15.0	$398.52	$239.11	0.3
1033	Warehouse	Air Conditioner - 14.3 IEER (20+ Tons)	MO	329.5	9.1%	30.0	0.0	0.0	15.0	15.0	$71.00	$42.60	0.5
1034	Warehouse	Air Conditioner - 15 IEER (20+ Tons)	MO	329.5	13.3%	43.9	0.0	0.0	15.0	15.0	$109.23	$65.54	0.5
1035	Warehouse	Air Conditioner - 17 IEER (20+ Tons)	MO	329.5	23.5%	77.5	0.1	0.0	15.0	15.0	$218.46	$131.08	0.5
1036	Warehouse	Comprehensive Rooftop Unit Quality Maintenance (AC Tune-up)	RETRO	356.9	7.0%	25.0	0.0	0.0	3.0	3.0	$11.42	$6.85	0.7
1037	Warehouse	Air Side Economizer	RETRO	293.4	20.0%	58.7	0.0	0.0	10.0	10.0	$126.67	$76.00	0.4
1038	Warehouse	HVAC Occupancy Controls	RETRO	309.6	20.0%	61.9	0.0	0.0	15.0	15.0	$197.50	$118.50	0.4
1039	Warehouse	Air Conditioner - 16 SEER (<5 Tons)	MO	305.9	12.5%	38.2	0.0	0.0	15.0	15.0	$115.00	$69.00	0.4
1040	Warehouse	Air Conditioner - 18 SEER(<5 Tons)	MO	305.9	22.2%	68.0	0.0	0.0	15.0	15.0	$514.00	$308.40	0.2
1041	Warehouse	Air Conditioner - 21 SEER (<5 Tons)	MO	305.9	33.3%	102.0	0.1	0.0	15.0	15.0	$630.50	$378.30	0.2
1042	Warehouse	Smart Thermostat	RETRO	1,755.9	14.2%	248.6	0.2	0.0	11.0	11.0	$175.00	$105.00	1.4
1043	Warehouse	PTAC - 7,000 to 15,000 Btuh	MO	394.8	14.6%	57.5	0.0	0.0	8.0	8.0	$84.00	$50.40	0.5
1044	Warehouse	Air Cooled Chiller	MO	312.6	9.0%	28.2	0.0	0.0	23.0	23.0	$126.00	$75.60	0.4
1045	Warehouse	Water Cooled Chiller	MO	157.1	22.7%	35.7	0.0	0.0	23.0	23.0	$61.00	$36.60	0.9
1046	Warehouse	Window Film	RETRO	6,363.6	4.4%	280.0	0.2	0.0	10.0	10.0	$153.81	$92.29	1.7
1047	Warehouse	Triple Pane Windows	MO	6,363.6	6.0%	381.8	0.2	0.0	25.0	25.0	$700.00	$420.00	0.9
1048	Warehouse	Energy Recovery Ventilator	RETRO	329.5	0.0%	0.0	0.0	0.0	15.0	15.0	$1,500.00	$900.00	0.0
1049	Warehouse	Heat Pump - 16 SEER (<5 Tons)	MO	1,534.7	6.0%	91.7	0.0	0.0	15.0	15.0	$135.00	$81.00	0.7
1050	Warehouse	Heat Pump - 18 SEER(<5 Tons)	MO	1,534.7	11.9%	182.0	0.0	0.0	15.0	15.0	$445.76	$267.46	0.4

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1051	Warehouse	Heat Pump - 21 SEER(<5 Tons)	MO	1,534.7	16.3%	249.4	0.1	0.1	15.0	15.0	$520.06	$312.04	0.5
1052	Warehouse	Heat Pump - 15.0 IEER COP 3.6 (65,000-134,000 Btu/hr)	MO	1,705.9	5.9%	100.3	0.0	0.0	15.0	15.0	$100.00	$60.00	1.0
1053	Warehouse	Heat Pump - 16.0 IEER COP 3.8 (65,000-134,000 Btu/hr)	MO	1,705.9	11.0%	187.6	0.0	0.0	15.0	15.0	$171.08	$102.65	1.1
1054	Warehouse	Heat Pump - 14.5 IEER COP 3.5 (135,000-239,000 Btu/hr)	MO	1,762.2	6.2%	108.9	0.0	0.0	15.0	15.0	$100.00	$60.00	1.1
1055	Warehouse	Heat Pump - 15.5 IEER COP 3.7 (135,000-239,000 Btu/hr)	MO	1,762.2	11.4%	201.4	0.0	0.0	15.0	15.0	$158.10	$94.86	1.3
1056	Warehouse	Heat Pump - 12 IEER 3.4 COP (>239,000 Btu/hr)	MO	1,829.5	5.9%	107.9	0.0	0.0	15.0	15.0	$100.00	$60.00	1.1
1057	Warehouse	Heat Pump - 13 IEER 3.6 COP (>239,000 Btu/hr)	MO	1,829.5	11.8%	215.4	0.0	0.0	15.0	15.0	$201.80	$121.08	1.1
1058	Warehouse	Geothermal HP - 17 EER < 135kbtu	MO	1,763.8	47.8%	842.3	0.2	0.2	25.0	25.0	$4,361.00	$2,616.60	0.2
1059	Warehouse	Geothermal HP - 19 EER < 135kbtu	MO	1,763.8	50.8%	896.5	0.2	0.2	25.0	25.0	$4,361.00	$2,616.60	0.3
1060	Warehouse	PTHP - 7,000 to 15,000 Btuh	MO	3,805.2	16.7%	634.2	0.1	0.1	15.0	15.0	$84.00	$50.40	7.6
1061	Warehouse	Heat Pump Water Heater	MO	10,590.6	73.3%	7,766.4	1.0	1.2	15.0	15.0	$1,797.00	$1,078.20	3.3
1062	Warehouse	Low Flow Faucet Aerator	RETRO	197.5	32.4%	63.9	0.0	0.0	10.0	10.0	$8.00	$4.80	4.4
1063	Warehouse	Pre-Rinse Spray Valves - DI	RETRO	18,058.7	54.2%	9,788.8	1.3	1.5	5.0	5.0	$54.00	$32.40	54.9
1064	Warehouse	Ozone Commercial Laundry	MO	2,984.0	25.0%	746.0	0.1	0.1	10.0	10.0	$20,309.70	$12,185.82	0.0
1065	Warehouse	Ext LED Replacing 100W MH (24/7)	RETRO	995.8	75.8%	754.8	0.0	0.1	10.0	10.0	$97.00	$58.20	2.8
1066	Warehouse	Ext LED Replacing 175W MH (24/7)	RETRO	1,743.6	71.0%	1,238.6	0.0	0.1	10.0	10.0	$123.81	$74.29	3.6
1067	Warehouse	Ext LED Replacing 250W MH (24/7)	RETRO	2,490.4	66.6%	1,658.5	0.0	0.2	10.0	10.0	$134.35	$80.61	4.5
1068	Warehouse	Ext LED Replacing 400W MH (24/7)	RETRO	3,984.1	64.5%	2,570.2	0.0	0.3	10.0	10.0	$196.16	$117.70	4.8
1069	Warehouse	Ext LED Replacing 1000W MH (24/7)	RETRO	9,467.3	70.4%	6,665.7	0.0	0.8	10.0	10.0	$319.31	$191.59	7.6
1070	Warehouse	Ext LED Replacing 100W MH (D2D)	RETRO	488.8	75.8%	370.5	0.0	0.0	10.0	10.0	$97.00	$58.20	1.4
1071	Warehouse	Ext LED Replacing 175W MH (D2D)	RETRO	855.9	71.0%	608.0	0.0	0.1	10.0	10.0	$123.81	$74.29	1.8
1072	Warehouse	Ext LED Replacing 250W MH (D2D)	RETRO	1,222.5	66.6%	814.1	0.0	0.1	10.0	10.0	$134.35	$80.61	2.2
1073	Warehouse	Ext LED Replacing 400W MH (D2D)	RETRO	1,955.7	64.5%	1,261.6	0.0	0.1	10.0	10.0	$196.16	$117.70	2.3
1074	Warehouse	Ext LED Replacing 1000W MH (D2D)	RETRO	4,647.2	70.4%	3,272.0	0.0	0.4	10.0	10.0	$319.31	$191.59	3.7
1075	Warehouse	LED Interior Direction (Track lighting / Wall-Wash Fixture)	RETRO	122.4	73.8%	90.3	0.0	0.0	15.0	15.0	$59.00	$35.40	1.1
1076	Warehouse	LED Linear Replacement Lamps (Replacing T8)	RETRO	88.4	51.4%	45.4	0.0	0.0	10.0	10.0	$15.00	$9.00	1.5
1077	Warehouse	LED Troffers (Replacing 1-Lamp T8)	RETRO	91.2	34.0%	31.0	0.0	0.0	15.0	15.0	$22.00	$13.20	1.0
1078	Warehouse	LED Troffers (Replacing 2-Lamp T8)	RETRO	178.6	51.4%	91.8	0.0	0.0	15.0	15.0	$61.00	$36.60	1.0
1079	Warehouse	LED Troffers (Replacing 3-Lamp T8)	RETRO	264.8	54.0%	143.1	0.0	0.0	15.0	15.0	$76.00	$45.60	1.3
1080	Warehouse	LED Troffers (Replacing 4-Lamp T8)	RETRO	352.9	54.3%	191.5	0.0	0.0	15.0	15.0	$104.00	$62.40	1.3
1081	Warehouse	LED Linear Ambient Fixture (<6000 lumens, replacing T8)	RETRO	178.2	50.3%	89.6	0.0	0.0	15.0	15.0	$46.67	$28.00	1.3
1082	Warehouse	LED Linear Ambient Fixture (>6000 lumens, replacing T5HO)	RETRO	470.1	53.2%	249.9	0.0	0.0	15.0	15.0	$152.00	$91.20	1.1
1083	Warehouse	LED Low-Bay Fixture	RETRO	492.0	67.0%	329.7	0.0	0.0	15.0	15.0	$42.88	$25.73	5.3
1084	Warehouse	LED High-Bay Fixture (Replacing T8 High Bay)	RETRO	921.3	57.0%	525.3	0.1	0.1	15.0	15.0	$48.07	$28.84	7.6
1085	Warehouse	LED High-Bay Fixture (Replacing Metal Halide)	RETRO	3,697.8	72.3%	2,673.7	0.4	0.3	15.0	15.0	$187.94	$112.76	9.9
1086	Warehouse	Fluorescent Delamping	RETRO	78.7	100.0%	78.7	0.0	0.0	11.0	11.0	$18.50	$11.10	2.3
1087	Warehouse	Lighting Occupancy Sensor	RETRO	408.6	30.0%	122.6	0.0	0.0	15.0	15.0	$65.40	$39.24	1.3
1088	Warehouse	Lighting Daylight Sensor	RETRO	523.3	28.0%	146.5	0.0	0.0	15.0	15.0	$57.50	$34.50	1.8
1089	Warehouse	Dual Occupancy / Daylight Sensor	RETRO	233.5	38.0%	88.7	0.0	0.0	15.0	15.0	$75.00	$45.00	0.8
1090	Warehouse	Luminaire-Level Lighting Controls	RETRO	233.5	61.0%	142.4	0.0	0.0	15.0	15.0	$56.00	$33.60	1.8
1091	Warehouse	Networked Lighting Control	RETRO	1.9	35.0%	0.7	0.0	0.0	15.0	15.0	$0.39	$0.24	1.2
1092	Warehouse	LED Exit Sign	RETRO	61.3	71.4%	43.8	0.0	0.0	5.0	5.0	$32.50	$19.50	0.4
1093	Warehouse	Non-Refrigerated Vending Machine Controls	RETRO	385.4	61.4%	236.8	0.0	0.0	5.0	5.0	$233.00	$139.80	0.3
1094	Warehouse	Kitchen Exhaust Hood Demand Ventilation Control System	MO	0.0	0.0%	0.0	0.0	0.0	20.0	20.0	$1.73	$1.04	0.0
1095	Warehouse	High Efficiency Hand Dryers	MO	261.6	83.0%	217.2	0.0	0.0	10.0	10.0	$483.00	$289.80	0.2
1096	Warehouse	ENERGY STAR Uninterrupted Power Supply	RETRO	3,125.1	3.7%	114.4	0.0	0.0	15.0	15.0	$59.00	$35.40	1.3
1097	Warehouse	Miscellaneous Custom	RETRO	6.7	15.0%	1.0	0.0	0.0	10.0	10.0	$0.40	$0.24	1.2
1098	Warehouse	Pump and Fan Variable Frequency Drive Controls (Pumps)	MO	538.2	27.7%	149.3	0.0	0.0	15.0	15.0	$198.32	$118.99	0.6
1099	Warehouse	Power Drive Systems	RETRO	4.3	23.0%	1.0	0.0	0.0	15.0	15.0	$0.13	$0.08	5.7
1100	Warehouse	Switch Reluctance Motors	MO	40,629.6	30.6%	12,432.6	1.8	1.6	15.0	15.0	$527.50	$316.50	17.3

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Measure #	Building Type	Measure Name	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW	RC EUL	EE EUL	Measure Cost	Incentive Amount	TRC
1101	Warehouse	Energy Star Printer/Copier/Fax	MO	418.0	26.3%	110.0	0.0	0.0	6.0	6.0	$0.00	$0.00	0.0
1102	Warehouse	Advanced Power Strip – Teri 1 Commercial Use	RETRO	188.2	57.7%	108.6	0.0	0.0	7.0	7.0	$10.00	$6.00	4.0
1103	Warehouse	Smart Socket	RETRO	79.9	60.6%	48.4	0.0	0.0	7.0	7.0	$9.00	$5.40	2.0
1104	Warehouse	Energy Star Server	MO	2,166.7	30.0%	650.0	0.1	0.1	9.0	9.0	$300.95	$180.57	1.0
1105	Warehouse	Server Virtualization	RETRO	2,166.7	13.9%	301.1	0.0	0.0	9.0	9.0	$26.97	$16.18	5.1
1106	Warehouse	Electrically Commutated Plug Fans in data centers	RETRO	86,783.0	18.2%	15,778.0	2.1	1.7	15.0	15.0	$480.00	$288.00	22.5
1107	Warehouse	Computer Room Air Conditioner Economizer	RETRO	764.0	46.9%	358.0	0.0	0.0	15.0	15.0	$82.00	$49.20	3.0
1108	Warehouse	High Efficiency CRAC unit	MO	8,940.1	25.3%	2,264.8	0.3	0.2	20.0	20.0	$750.00	$450.00	2.6
1109	Warehouse	Data Center Hot/Cold Aisle Configuration	RETRO	13.3	7.5%	1.0	0.0	0.0	10.0	10.0	$0.23	$0.14	2.2
1110	Warehouse	Strip Curtains	RETRO	206.8	50.0%	103.4	0.0	0.0	4.0	4.0	$10.22	$6.13	2.3
1111	Warehouse	Floating Head Pressure Controls	RETRO	1,228.0	25.0%	307.0	0.0	0.0	15.0	15.0	$431.00	$258.60	0.5
1112	Warehouse	Electronically Commutated (EC) Walk-In Evaporator Fan Motor	RETRO	2,883.6	55.0%	1,586.0	0.2	0.2	15.0	15.0	$305.00	$183.00	3.6
1113	Warehouse	Evaporator Fan Motor Controls	RETRO	1,297.6	22.6%	293.0	0.0	0.0	13.0	13.0	$161.75	$97.05	1.1
1114	Warehouse	Variable Speed Condenser Fan	RETRO	3,157.9	47.5%	1,500.0	0.2	0.2	15.0	15.0	$1,170.00	$702.00	0.9
1115	Warehouse	Door Heater Controls for Cooler	RETRO	578.6	41.5%	240.1	0.0	0.0	10.0	10.0	$79.50	$47.70	1.5
1116	Warehouse	Automated Door Closer for Refrigerator	RETRO	1,259,892.8	0.2%	2,398.7	0.3	0.3	8.0	8.0	$502.00	$301.20	2.0
1117	Warehouse	Aerofoils for Open Display Cases	RETRO	45,880.0	10.0%	4,588.0	0.6	0.5	10.0	10.0	$311.54	$186.92	7.4
1118	Warehouse	Display Case Door Retrofit, Medium Temp	RETRO	1,558.3	50.0%	779.1	0.1	0.1	15.0	15.0	$390.00	$234.00	1.4
1119	Warehouse	Electronically Commutated (EC) Reach-In Evaporator Fan Motor	RETRO	2,883.6	55.0%	1,586.0	0.2	0.2	15.0	15.0	$305.00	$183.00	3.6
1120	Warehouse	Q-Sync Motor for Walk-In and Reach-in Evaporator Fan Motor	RETRO	2,090.6	24.1%	504.6	0.1	0.1	10.0	10.0	$96.00	$57.60	2.7
1121	Warehouse	Night Covers for Coolers	RETRO	1,510.5	9.0%	136.0	0.0	0.0	5.0	5.0	$42.00	$25.20	0.9
1122	Warehouse	Door Heater Controls for Freezer	RETRO	2,016.2	32.5%	655.3	0.1	0.1	10.0	10.0	$79.50	$47.70	4.2
1123	Warehouse	Automated Door Closer for Freezer	RETRO	1,259,892.8	0.6%	6,948.8	1.0	0.8	8.0	8.0	$502.00	$301.20	5.8
1124	Warehouse	Night Covers for Freezers	RETRO	2,349.3	9.0%	211.3	0.0	0.0	5.0	5.0	$42.00	$25.20	1.4
1125	Warehouse	Refrigeration - Custom	RETRO	6.7	15.0%	1.0	0.0	0.0	10.0	10.0	$0.40	$0.24	1.3
1126	Warehouse	Retro-commissioning_Refrigerator Optimization	RETRO	4.8	21.0%	1.0	0.0	0.0	5.0	5.0	$0.22	$0.13	1.3
1127	Warehouse	ESTAR Refrigerated Vending Machine	MO	1,277.5	12.0%	153.3	0.0	0.0	14.0	14.0	$500.00	$300.00	0.2
1128	Warehouse	Refrigerated Vending Machine Controls	RETRO	1,662.9	23.5%	390.1	0.1	0.0	5.0	5.0	$245.00	$147.00	0.4
1129	Warehouse	Commercial Ice Marker	MO	5,550.9	7.9%	440.3	0.1	0.0	9.0	9.0	$222.00	$133.20	0.9
1130	Warehouse	LED Refrigerated Display Case Lighting Average 6W/LF	MO	114.6	73.7%	84.5	0.0	0.0	9.0	9.0	$11.00	$6.60	3.5
1131	Warehouse	Pump and Fan Variable Frequency Drive Controls (Fans)	RETRO	13,008.0	59.0%	7,673.8	1.0	1.3	15.0	15.0	$2,250.00	$1,350.00	2.6
1132	Warehouse	Cogged V-Belt (Synchronous)	RETRO	20,964.7	3.1%	649.9	0.1	0.1	15.0	15.0	$381.00	$228.60	1.2
1133	Warehouse	HVAC - Energy Management System	RETRO	12.5	8.0%	1.0	0.0	0.0	15.0	15.0	$0.40	$0.24	1.7
1134	Warehouse	GREM Controls	RETRO	0.0	0.0%	0.0	0.0	0.0	15.0	15.0	$0.00	$0.00	0.0
1135	Warehouse	Demand Control Ventilation	RETRO	0.0	0.0%	0.0	0.0	0.0	10.0	10.0	$235.60	$141.36	0.0
1136	Warehouse	High Efficiency DOAS	RETRO	5.2	35.7%	1.9	0.0	0.0	15.0	15.0	$15.22	$9.13	0.1
1137	Warehouse	Advanced Rooftop Controls	RETRO	0.0	0.0%	0.0	0.0	0.0	10.0	10.0	$341.21	$204.72	0.0
1138	Warehouse	Retro-commissioning_Bld Optimization	RETRO	12.5	8.0%	1.0	0.0	0.0	15.0	15.0	$0.12	$0.07	5.6
1139	Warehouse	Commercial Weatherstripping	RETRO	222.3	2.0%	4.4	0.0	0.0	10.0	10.0	$8.00	$4.80	0.3
1140	Warehouse	WholeBlg - Com RET	RETRO	6.7	15.0%	1.0	0.0	0.0	15.0	15.0	$0.40	$0.24	1.7
1141	Warehouse	Strategic Energy Management	RETRO	0.0	0.0%	0.0	0.0	0.0	5.0	5.0	$0.27	$0.16	0.5
1142	Warehouse	Power Distribution Equipment Upgrades (Transformers)	RETRO	990.2	0.6%	5.5	0.0	0.0	30.0	30.0	$6.27	$3.76	0.7
1143	Warehouse	WholeBlg - Com NC	NC	4.0	25.0%	1.0	0.0	0.0	15.0	15.0	$0.40	$0.24	1.7
1144	Other	Commercial Combination Oven (Electric)	MO	19,496.1	38.6%	7,532.5	1.3	1.0	12.0	12.0	$2,270.00	$1,362.00	2.1
1145	Other	Commercial Electric Convection Oven	MO	10,863.7	19.0%	2,064.2	0.3	0.3	12.0	12.0	$960.00	$576.00	1.4
1146	Other	Commercial Electric Griddle	MO	17,056.0	15.2%	2,596.0	0.4	0.3	12.0	12.0	$0.00	$0.00	0.0
1147	Other	Commercial Electric Steam Cooker	MO	16,914.5	79.9%	13,506.7	2.3	1.7	12.0	12.0	$2,757.00	$1,654.20	3.2
1148	Other	Dishwasher Low Temp Door (Energy Star)	MO	35,655.0	44.2%	15,765.8	2.7	2.0	16.0	16.0	$466.50	$279.90	27.2
1149	Other	Dishwasher High Temp Door (Energy Star)	MO	38,282.0	16.4%	6,278.8	1.1	0.8	15.0	15.0	$1,550.00	$930.00	3.1
1150	Other	Energy efficient electric fryer	MO	18,955.0	17.3%	3,274.0	0.6	0.4	12.0	12.0	$1,500.00	$900.00	1.4

Big Rivers | **Measure Assumption Tab**

Measure #	Building Type	Measure Name	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW	RC EUL	EE EUL	Measure Cost	Incentive Amount	TRC
1151	Other	Insulated Holding Cabinets	MO	1,478.3	36.9%	545.3	0.1	0.1	12.0	12.0	$1,000.00	$600.00	0.4
1152	Other	Compressed Air Leak Repair	RETRO	5.9	17.0%	1.0	0.0	0.0	3.0	3.0	$0.08	$0.05	2.2
1153	Other	Retro-commissioning_Compressed Air Optimization	RETRO	4.8	21.0%	1.0	0.0	0.0	5.0	5.0	$0.22	$0.13	1.2
1154	Other	Efficient Air Compressors (VSD)	MO	23,741.6	20.8%	4,935.1	0.6	0.6	13.0	13.0	$3,367.84	$2,020.70	0.9
1155	Other	No Loss Condensate Drain	RETRO	476,153.6	0.4%	1,969.7	0.2	0.2	10.0	10.0	$244.00	$146.40	4.0
1156	Other	Efficient Air Nozzles	MO	1,129.7	50.0%	564.9	0.1	0.1	15.0	15.0	$57.00	$34.20	6.7
1157	Other	Air Conditioner - 17 IEER (5-20 Tons)	MO	994.1	14.1%	140.3	0.1	0.0	15.0	15.0	$153.28	$91.97	0.9
1158	Other	Air Conditioner - 18 IEER (5-20 Tons)	MO	994.1	18.9%	187.8	0.1	0.0	15.0	15.0	$214.59	$128.75	0.9
1159	Other	Air Conditioner - 21 IEER (5-20 Tons)	MO	994.1	30.5%	303.0	0.1	0.0	15.0	15.0	$398.52	$239.11	0.8
1160	Other	Air Conditioner - 14.3 IEER (20+ Tons)	MO	1,116.4	9.1%	101.5	0.0	0.0	15.0	15.0	$71.00	$42.60	1.5
1161	Other	Air Conditioner - 15 IEER (20+ Tons)	MO	1,116.4	13.3%	148.9	0.1	0.0	15.0	15.0	$109.23	$65.54	1.4
1162	Other	Air Conditioner - 17 IEER (20+ Tons)	MO	1,116.4	23.5%	262.7	0.1	0.0	15.0	15.0	$218.46	$131.08	1.2
1163	Other	Comprehensive Rooftop Unit Quality Maintenance (AC Tune-up)	RETRO	1,209.4	7.0%	84.7	0.0	0.0	3.0	3.0	$11.42	$6.85	1.9
1164	Other	Air Side Economizer	RETRO	994.1	20.0%	198.8	0.1	0.0	10.0	10.0	$126.67	$76.00	1.2
1165	Other	HVAC Occupancy Controls	RETRO	1,049.0	20.0%	209.8	0.1	0.0	15.0	15.0	$197.50	$118.50	1.1
1166	Other	Air Conditioner - 16 SEER (<5 Tons)	MO	1,036.7	12.5%	129.6	0.1	0.0	15.0	15.0	$115.00	$69.00	1.1
1167	Other	Air Conditioner - 18 SEER(<5 Tons)	MO	1,036.7	22.2%	230.4	0.1	0.0	15.0	15.0	$514.00	$308.40	0.5
1168	Other	Air Conditioner - 21 SEER (<5 Tons)	MO	1,036.7	33.3%	345.6	0.2	0.0	15.0	15.0	$630.50	$378.30	0.6
1169	Other	Smart Thermostat	RETRO	5,949.7	14.2%	842.5	0.4	0.0	11.0	11.0	$175.00	$105.00	3.8
1170	Other	PTAC - 7,000 to 15,000 Btuh	MO	1,337.6	14.6%	194.9	0.1	0.0	8.0	8.0	$84.00	$50.40	1.4
1171	Other	Air Cooled Chiller	MO	1,059.4	9.0%	95.4	0.0	0.0	23.0	23.0	$126.00	$75.60	1.0
1172	Other	Water Cooled Chiller	MO	532.2	22.7%	120.9	0.1	0.0	23.0	23.0	$61.00	$36.60	2.5
1173	Other	Window Film	RETRO	6,363.6	4.4%	280.0	0.1	0.0	10.0	10.0	$153.81	$92.29	1.3
1174	Other	Triple Pane Windows	MO	6,363.6	6.0%	381.8	0.2	0.0	25.0	25.0	$700.00	$420.00	0.7
1175	Other	Energy Recovery Ventilator	RETRO	1,116.4	0.0%	0.0	0.0	0.0	15.0	15.0	$1,500.00	$900.00	0.0
1176	Other	Heat Pump - 16 SEER (<5 Tons)	MO	2,607.0	7.6%	197.9	0.0	0.0	15.0	15.0	$135.00	$81.00	1.3
1177	Other	Heat Pump - 18 SEER(<5 Tons)	MO	2,607.0	14.4%	376.1	0.1	0.1	15.0	15.0	$445.76	$267.46	0.8
1178	Other	Heat Pump - 21 SEER(<5 Tons)	MO	2,607.0	20.5%	534.0	0.1	0.1	15.0	15.0	$520.06	$312.04	0.9
1179	Other	Heat Pump - 15.0 IEER COP 3.6 (65,000-134,000 Btu/hr)	MO	2,830.4	6.2%	175.8	0.0	0.0	15.0	15.0	$100.00	$60.00	1.6
1180	Other	Heat Pump - 16.0 IEER COP 3.8 (65,000-134,000 Btu/hr)	MO	2,830.4	11.5%	325.1	0.1	0.1	15.0	15.0	$171.08	$102.65	1.7
1181	Other	Heat Pump - 14.5 IEER COP 3.5 (135,000-239,000 Btu/hr)	MO	2,931.7	6.7%	195.5	0.0	0.0	15.0	15.0	$100.00	$60.00	1.8
1182	Other	Heat Pump - 15.5 IEER COP 3.7 (135,000-239,000 Btu/hr)	MO	2,931.7	12.1%	353.9	0.1	0.1	15.0	15.0	$158.10	$94.86	2.0
1183	Other	Heat Pump - 12 IEER 3.4 COP (>239,000 Btu/hr)	MO	3,073.0	6.6%	203.2	0.0	0.0	15.0	15.0	$100.00	$60.00	1.9
1184	Other	Heat Pump - 13 IEER 3.6 COP (>239,000 Btu/hr)	MO	3,073.0	12.6%	386.8	0.1	0.1	15.0	15.0	$201.80	$121.08	1.7
1185	Other	Geothermal HP - 17 EER < 135kbtu	MO	2,933.8	41.1%	1,204.3	0.2	0.3	25.0	25.0	$4,361.00	$2,616.60	0.3
1186	Other	Geothermal HP - 19 EER < 135kbtu	MO	2,933.8	44.5%	1,306.1	0.2	0.3	25.0	25.0	$4,361.00	$2,616.60	0.3
1187	Other	PTHP - 7,000 to 15,000 Btuh	MO	5,597.8	16.7%	933.0	0.1	0.2	15.0	15.0	$84.00	$50.40	10.1
1188	Other	Heat Pump Water Heater	MO	17,236.9	73.3%	12,640.4	1.7	1.9	15.0	15.0	$1,797.00	$1,078.20	5.3
1189	Other	Low Flow Faucet Aerator	RETRO	394.9	32.4%	127.8	0.0	0.0	10.0	10.0	$8.00	$4.80	8.8
1190	Other	Pre-Rinse Spray Valves - DI	RETRO	18,058.7	54.2%	9,788.8	1.3	1.5	5.0	5.0	$54.00	$32.40	54.9
1191	Other	Ozone Commercial Laundry	MO	2,984.0	25.0%	746.0	0.1	0.1	10.0	10.0	$20,309.70	$12,185.82	0.0
1192	Other	Ext LED Replacing 100W MH (24/7)	RETRO	995.8	75.8%	754.8	0.0	0.1	10.0	10.0	$97.00	$58.20	2.8
1193	Other	Ext LED Replacing 175W MH (24/7)	RETRO	1,743.6	71.0%	1,238.6	0.0	0.1	10.0	10.0	$123.81	$74.29	3.6
1194	Other	Ext LED Replacing 250W MH (24/7)	RETRO	2,490.4	66.6%	1,658.5	0.0	0.2	10.0	10.0	$134.35	$80.61	4.4
1195	Other	Ext LED Replacing 400W MH (24/7)	RETRO	3,984.1	64.5%	2,570.2	0.0	0.3	10.0	10.0	$196.16	$117.70	4.7
1196	Other	Ext LED Replacing 1000W MH (24/7)	RETRO	9,467.3	70.4%	6,665.7	0.0	0.8	10.0	10.0	$319.31	$191.59	7.5
1197	Other	Ext LED Replacing 100W MH (D2D)	RETRO	488.8	75.8%	370.5	0.0	0.0	10.0	10.0	$97.00	$58.20	1.4
1198	Other	Ext LED Replacing 175W MH (D2D)	RETRO	855.9	71.0%	608.0	0.0	0.1	10.0	10.0	$123.81	$74.29	1.8
1199	Other	Ext LED Replacing 250W MH (D2D)	RETRO	1,222.5	66.6%	814.1	0.0	0.1	10.0	10.0	$134.35	$80.61	2.2
1200	Other	Ext LED Replacing 400W MH (D2D)	RETRO	1,955.7	64.5%	1,261.6	0.0	0.1	10.0	10.0	$196.16	$117.70	2.3

Big Rivers | **Measure Assumption Tab**

Measure #	Building Type	Measure Name	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW	RC EUL	EE EUL	Measure Cost	Incentive Amount	TRC
1201	Other	Ext LED Replacing 1000W MH (D2D)	RETRO	4,647.2	70.4%	3,272.0	0.0	0.4	10.0	10.0	$319.31	$191.59	3.7
1202	Other	LED Interior Direction (Track lighting / Wall-Wash Fixture)	RETRO	139.7	73.8%	103.0	0.0	0.0	15.0	15.0	$59.00	$35.40	1.2
1203	Other	LED Linear Replacement Lamps (Replacing T8)	RETRO	100.9	51.4%	51.9	0.0	0.0	10.0	10.0	$15.00	$9.00	1.7
1204	Other	LED Troffers (Replacing 1-Lamp T8)	RETRO	104.1	34.0%	35.4	0.0	0.0	15.0	15.0	$22.00	$13.20	1.1
1205	Other	LED Troffers (Replacing 2-Lamp T8)	RETRO	203.9	51.4%	104.8	0.0	0.0	15.0	15.0	$61.00	$36.60	1.2
1206	Other	LED Troffers (Replacing 3-Lamp T8)	RETRO	302.2	54.0%	163.3	0.0	0.0	15.0	15.0	$76.00	$45.60	1.5
1207	Other	LED Troffers (Replacing 4-Lamp T8)	RETRO	402.7	54.3%	218.5	0.0	0.0	15.0	15.0	$104.00	$62.40	1.5
1208	Other	LED Linear Ambient Fixture (<6000 lumens, replacing T8)	RETRO	203.4	50.3%	102.3	0.0	0.0	15.0	15.0	$46.67	$28.00	1.5
1209	Other	LED Linear Ambient Fixture (>6000 lumens, replacing T5HO)	RETRO	536.5	53.2%	285.2	0.0	0.0	15.0	15.0	$152.00	$91.20	1.3
1210	Other	LED Low-Bay Fixture	RETRO	561.5	67.0%	376.2	0.0	0.0	15.0	15.0	$42.88	$25.73	6.1
1211	Other	LED High-Bay Fixture (Replacing T8 High Bay)	RETRO	1,051.4	57.0%	599.5	0.1	0.1	15.0	15.0	$48.07	$28.84	8.7
1212	Other	LED High-Bay Fixture (Replacing Metal Halide)	RETRO	4,220.1	72.3%	3,051.3	0.4	0.4	15.0	15.0	$187.94	$112.76	11.3
1213	Other	Fluorescent Delamping	RETRO	89.8	100.0%	89.8	0.0	0.0	11.0	11.0	$18.50	$11.10	2.6
1214	Other	Lighting Occupancy Sensor	RETRO	466.4	30.0%	139.9	0.0	0.0	15.0	15.0	$65.40	$39.24	1.5
1215	Other	Lighting Daylight Sensor	RETRO	597.2	28.0%	167.2	0.0	0.0	15.0	15.0	$57.50	$34.50	2.0
1216	Other	Dual Occupancy / Daylight Sensor	RETRO	266.4	38.0%	101.2	0.0	0.0	15.0	15.0	$75.00	$45.00	0.9
1217	Other	Luminaire-Level Lighting Controls	RETRO	266.4	61.0%	162.5	0.0	0.0	15.0	15.0	$56.00	$33.60	2.0
1218	Other	Networked Lighting Control	RETRO	2.2	35.0%	0.8	0.0	0.0	15.0	15.0	$0.45	$0.27	1.2
1219	Other	LED Exit Sign	RETRO	64.9	71.4%	46.4	0.0	0.0	5.0	5.0	$32.50	$19.50	0.4
1220	Other	Non-Refrigerated Vending Machine Controls	RETRO	385.4	61.4%	236.8	0.0	0.0	5.0	5.0	$233.00	$139.80	0.3
1221	Other	Kitchen Exhaust Hood Demand Ventilation Control System	MO	0.0	0.0%	0.0	0.0	0.0	20.0	20.0	$1.73	$1.04	0.0
1222	Other	High Efficiency Hand Dryers	MO	261.6	83.0%	217.2	0.0	0.0	10.0	10.0	$483.00	$289.80	0.2
1223	Other	ENERGY STAR Uninterrupted Power Supply	RETRO	3,125.1	3.7%	114.4	0.0	0.0	15.0	15.0	$59.00	$35.40	1.3
1224	Other	Miscellaneous Custom	RETRO	6.7	15.0%	1.0	0.0	0.0	10.0	10.0	$0.40	$0.24	1.2
1225	Other	Pump and Fan Variable Frequency Drive Controls (Pumps)	MO	2,087.7	27.7%	579.0	0.1	0.1	15.0	15.0	$198.32	$118.99	2.3
1226	Other	Power Drive Systems	RETRO	4.3	23.0%	1.0	0.0	0.0	15.0	15.0	$0.13	$0.08	6.0
1227	Other	Switch Reluctance Motors	MO	33,405.7	30.6%	10,222.1	2.1	1.0	15.0	15.0	$527.50	$316.50	15.1
1228	Other	Energy Star Printer/Copier/Fax	MO	418.0	26.3%	110.0	0.0	0.0	6.0	6.0	$0.00	$0.00	0.0
1229	Other	Advanced Power Strip – Teri 1 Commercial Use	RETRO	188.2	57.7%	108.6	0.0	0.0	7.0	7.0	$10.00	$6.00	4.0
1230	Other	Smart Socket	RETRO	79.9	60.6%	48.4	0.0	0.0	7.0	7.0	$9.00	$5.40	2.0
1231	Other	Energy Star Server	MO	2,166.7	30.0%	650.0	0.1	0.1	9.0	9.0	$300.95	$180.57	1.0
1232	Other	Server Virtualization	RETRO	2,166.7	13.9%	301.1	0.0	0.0	9.0	9.0	$26.97	$16.18	5.0
1233	Other	Electrically Commutated Plug Fans in data centers	RETRO	86,783.0	18.2%	15,778.0	1.9	1.9	15.0	15.0	$480.00	$288.00	22.3
1234	Other	Computer Room Air Conditioner Economizer	RETRO	764.0	46.9%	358.0	0.0	0.0	15.0	15.0	$82.00	$49.20	3.0
1235	Other	High Efficiency CRAC unit	MO	8,940.1	25.3%	2,264.8	0.3	0.3	20.0	20.0	$750.00	$450.00	2.5
1236	Other	Data Center Hot/Cold Aisle Configuration	RETRO	13.3	7.5%	1.0	0.0	0.0	10.0	10.0	$0.23	$0.14	2.2
1237	Other	Strip Curtains	RETRO	36.6	50.0%	18.3	0.0	0.0	4.0	4.0	$10.22	$6.13	0.4
1238	Other	Floating Head Pressure Controls	RETRO	1,228.0	25.0%	307.0	0.0	0.0	15.0	15.0	$431.00	$258.60	0.5
1239	Other	Electronically Commutated (EC) Walk-In Evaporator Fan Motor	RETRO	2,883.6	55.0%	1,586.0	0.2	0.2	15.0	15.0	$305.00	$183.00	3.6
1240	Other	Evaporator Fan Motor Controls	RETRO	1,297.6	22.6%	293.0	0.0	0.0	13.0	13.0	$161.75	$97.05	1.1
1241	Other	Variable Speed Condenser Fan	RETRO	3,157.9	47.5%	1,500.0	0.2	0.2	15.0	15.0	$1,170.00	$702.00	0.9
1242	Other	Door Heater Controls for Cooler	RETRO	578.6	41.5%	240.1	0.0	0.0	10.0	10.0	$79.50	$47.70	1.5
1243	Other	Automated Door Closer for Refrigerator	RETRO	1,259,892.8	0.2%	2,398.7	0.3	0.3	8.0	8.0	$502.00	$301.20	2.0
1244	Other	Aerofoils for Open Display Cases	RETRO	45,880.0	10.0%	4,588.0	0.6	0.5	10.0	10.0	$311.54	$186.92	7.4
1245	Other	Display Case Door Retrofit, Medium Temp	RETRO	1,558.3	50.0%	779.1	0.1	0.1	15.0	15.0	$390.00	$234.00	1.4
1246	Other	Electronically Commutated (EC) Reach-In Evaporator Fan Motor	RETRO	2,883.6	55.0%	1,586.0	0.2	0.2	15.0	15.0	$305.00	$183.00	3.6
1247	Other	Q-Sync Motor for Walk-In and Reach-in Evaporator Fan Motor	RETRO	2,090.6	24.1%	504.6	0.1	0.1	10.0	10.0	$96.00	$57.60	2.7
1248	Other	Night Covers for Coolers	RETRO	1,510.5	9.0%	136.0	0.0	0.0	5.0	5.0	$42.00	$25.20	0.9
1249	Other	Door Heater Controls for Freezer	RETRO	2,016.2	32.5%	655.3	0.1	0.1	10.0	10.0	$79.50	$47.70	4.2
1250	Other	Automated Door Closer for Freezer	RETRO	1,259,892.8	0.6%	6,948.8	1.0	0.8	8.0	8.0	$502.00	$301.20	5.8

Big Rivers — **Measure Assumption Tab**

Measure #	Building Type	Measure Name	Replacement Type	Base Annual Electric	% Elec Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW	RC EUL	EE EUL	Measure Cost	Incentive Amount	TRC
1251	Other	Night Covers for Freezers	RETRO	2,349.3	9.0%	211.3	0.0	0.0	5.0	5.0	$42.00	$25.20	1.4
1252	Other	Refrigeration - Custom	RETRO	6.7	15.0%	1.0	0.0	0.0	10.0	10.0	$0.40	$0.24	1.3
1253	Other	Retro-commissioning_Refrigerator Optimization	RETRO	4.8	21.0%	1.0	0.0	0.0	5.0	5.0	$0.22	$0.13	1.3
1254	Other	ESTAR Refrigerated Vending Machine	MO	1,277.5	12.0%	153.3	0.0	0.0	14.0	14.0	$500.00	$300.00	0.2
1255	Other	Refrigerated Vending Machine Controls	RETRO	1,662.9	23.5%	390.1	0.1	0.0	5.0	5.0	$245.00	$147.00	0.4
1256	Other	Commercial Ice Marker	MO	5,550.9	7.9%	440.3	0.1	0.0	9.0	9.0	$222.00	$133.20	0.9
1257	Other	LED Refrigerated Display Case Lighting Average 6W/LF	MO	114.6	73.7%	84.5	0.0	0.0	9.0	9.0	$11.00	$6.60	3.5
1258	Other	Pump and Fan Variable Frequency Drive Controls (Fans)	RETRO	11,882.8	59.0%	7,010.0	1.2	1.1	15.0	15.0	$2,250.00	$1,350.00	2.5
1259	Other	Cogged V-Belt (Synchronous)	RETRO	17,237.2	3.1%	534.4	0.1	0.1	15.0	15.0	$381.00	$228.60	1.0
1260	Other	HVAC - Energy Management System	RETRO	12.5	8.0%	1.0	0.0	0.0	15.0	15.0	$0.40	$0.24	1.9
1261	Other	GREM Controls	RETRO	0.0	0.0%	0.0	0.0	0.0	15.0	15.0	$0.00	$0.00	0.0
1262	Other	Demand Control Ventilation	RETRO	1,925.0	20.0%	385.0	0.1	0.0	10.0	10.0	$235.60	$141.36	0.9
1263	Other	High Efficiency DOAS	RETRO	5.2	35.7%	1.9	0.0	0.0	15.0	15.0	$15.22	$9.13	0.1
1264	Other	Advanced Rooftop Controls	RETRO	0.0	0.0%	0.0	0.0	0.0	10.0	10.0	$341.21	$204.72	0.0
1265	Other	Retro-commissioning_Bld Optimization	RETRO	12.5	8.0%	1.0	0.0	0.0	15.0	15.0	$0.12	$0.07	6.2
1266	Other	Commercial Weatherstripping	RETRO	222.3	2.0%	4.4	0.0	0.0	10.0	10.0	$8.00	$4.80	0.3
1267	Other	WholeBlg - Com RET	RETRO	6.7	15.0%	1.0	0.0	0.0	15.0	15.0	$0.40	$0.24	1.9
1268	Other	Strategic Energy Management	RETRO	0.0	0.0%	0.0	0.0	0.0	5.0	5.0	$0.27	$0.16	0.6
1269	Other	Power Distribution Equipment Upgrades (Transformers)	RETRO	990.2	0.6%	5.5	0.0	0.0	30.0	30.0	$6.27	$3.76	0.8
1270	Other	WholeBlg - Com NC	NC	4.0	25.0%	1.0	0.0	0.0	15.0	15.0	$0.40	$0.24	1.9
1271	Industrial	Efficient Air Compressor Equipment	MO	8.8	11.3%	1.0	0.0	0.0	13.0	13.0	$0.41	$0.25	1.7
1272	Industrial	Efficient Air Compressor Controls	RETRO	15.2	6.6%	1.0	0.0	0.0	3.0	3.0	$0.12	$0.07	1.6
1273	Industrial	Efficient HVAC Equipment	MO	7.7	13.0%	1.0	0.0	0.0	15.0	15.0	$0.19	$0.12	3.4
1274	Industrial	Efficient HVAC O&M	RETRO	33.3	3.0%	1.0	0.0	0.0	3.0	3.0	$0.09	$0.06	1.8
1275	Industrial	Efficient Lighting Equipment	RETRO	2.4	42.0%	1.0	0.0	0.0	15.0	15.0	$0.17	$0.10	4.5
1276	Industrial	Efficient Lighting O&M	RETRO	33.3	3.0%	1.0	0.0	0.0	3.0	3.0	$0.07	$0.04	2.8
1277	Industrial	Efficient MachDr Equipment	MO	8.3	12.0%	1.0	0.0	0.0	15.0	15.0	$0.17	$0.10	4.0
1278	Industrial	Efficient MachDr O&M	RETRO	33.3	3.0%	1.0	0.0	0.0	3.0	3.0	$0.10	$0.06	1.8
1279	Industrial	Efficient ProcHeat Equipment	MO	33.3	3.0%	1.0	0.0	0.0	15.0	15.0	$0.17	$0.10	4.5
1280	Industrial	Efficient ProcHeat O&M	RETRO	33.3	3.0%	1.0	0.0	0.0	3.0	3.0	$0.08	$0.05	2.6
1281	Industrial	Efficient ProcRefrig Equipment	MO	6.4	15.7%	1.0	0.0	0.0	15.0	15.0	$0.18	$0.11	3.8
1282	Industrial	Efficient ProcRefrig O&M	RETRO	33.3	3.0%	1.0	0.0	0.0	3.0	3.0	$0.11	$0.06	1.6
1283	Industrial	Other Process Equip	MO	3.9	25.6%	1.0	0.0	0.0	11.0	11.0	$0.35	$0.21	1.8
1284	Industrial	Other Process O&M	RETRO	14.3	7.0%	1.0	0.0	0.0	11.0	11.0	$0.30	$0.18	2.1
1285	Industrial	Power Distribution (Transformers)	RETRO	178.6	0.6%	1.0	0.0	0.0	30.0	30.0	$1.17	$0.70	0.9
1286	Industrial	Strategic Energy Management	RETRO	33.3	3.0%	1.0	0.0	0.0	3.0	3.0	$0.09	$0.05	2.3
1287	Industrial	Water Supply & Wastewater treatment pumps and process efficie	RETRO	5.4	18.5%	1.0	0.0	0.0	11.0	11.0	$0.45	$0.27	1.2
1288	Agriculture	Efficient Motor Pmp Equipment - Q1 Cost	MO	7.6	13.1%	1.0	0.0	0.0	15.0	15.0	$0.01	$0.00	113.8
1289	Agriculture	Efficient Motor Pmp Equipment - Q2 Cost	MO	7.6	13.1%	1.0	0.0	0.0	15.0	15.0	$0.02	$0.01	37.9
1290	Agriculture	Efficient Motor Pmp Equipment - Q3 Cost	MO	7.6	13.1%	1.0	0.0	0.0	15.0	15.0	$0.05	$0.03	13.7
1291	Agriculture	Efficient Motor Pmp O&M	RETRO	33.3	3.0%	1.0	0.0	0.0	15.0	15.0	$0.10	$0.06	7.2
1292	Agriculture	Efficient Refrigeration Equipment	MO	6.6	15.1%	1.0	0.0	0.0	15.0	15.0	$0.18	$0.11	3.8
1293	Agriculture	Refrigeration Equipment O&M	RETRO	33.3	3.0%	1.0	0.0	0.0	3.0	3.0	$0.11	$0.06	1.6
1294	Agriculture	Efficient Lighting	RETRO	2.4	42.0%	1.0	0.0	0.0	15.0	15.0	$0.17	$0.10	4.4
1295	Agriculture	Grow Lighting	RETRO	2.6	39.0%	1.0	0.0	0.0	15.0	15.0	$0.27	$0.16	2.9
1296	Agriculture	Efficient Ventilation	MO	1.9	54.0%	1.0	0.0	0.0	10.0	10.0	$0.32	$0.19	1.5
1297	Agriculture	Efficient Dehumidification	MO	3.7	27.0%	1.0	0.0	0.0	10.0	10.0	$0.19	$0.11	2.5
1298	Agriculture	Efficient HVAC	MO	7.7	13.0%	1.0	0.0	0.0	15.0	15.0	$0.19	$0.11	3.5

APPENDIX C: MODELING ASSUMPTIONS

GENERAL MODELING ASSUMPTIONS

Analysis Start Year	2027	
Analysis TimeFrame (Years)	15	
Inflation Rate (%):	2.50%	Big Rivers
Nominal Discount Rate (%):	4.75%	Big Rivers
Societal Discount Rate (%)	6.00%	GDS

AVOIDED COSTS AND RETAIL RATES ASSUMPTIONS (Nominal Dollars)

Electric Avoided Cost Type	Unit	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Summer On Peak Energy	($/kwh)	0.026	0.025	0.024	0.024	0.023	0.024	0.024	0.024	0.025	0.024	0.023	0.024	0.024	0.025	0.026
Summer Off-Peak Energy	($/kwh)	0.026	0.025	0.024	0.024	0.023	0.024	0.024	0.024	0.025	0.024	0.023	0.024	0.024	0.025	0.026
Winter On Peak Energy	($/kwh)	0.026	0.025	0.024	0.024	0.023	0.024	0.024	0.024	0.025	0.024	0.023	0.024	0.024	0.025	0.026
Winter Off-Peak Energy	($/kwh)	0.026	0.025	0.024	0.024	0.023	0.024	0.024	0.024	0.025	0.024	0.023	0.024	0.024	0.025	0.026
Summer Generation Capacity	($/kW-YR)	106.41	108.54	110.66	112.87	114.27	116.54	118.79	120.23	122.61	124.96	127.36	128.78	131.24	133.73	136.27
Winter Generation Capacity	($/kW-YR)	106.41	108.54	110.66	112.87	114.27	116.54	118.79	120.23	122.61	124.96	127.36	128.78	131.24	133.73	136.27
Avoided Transmission Capacity	($/kW-YR)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Avoided Distribution Capacity	($/kW-YR)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electric Retail Rate	($/kwh)	0.159	0.163	0.167	0.171	0.175	0.180	0.184	0.189	0.194	0.199	0.203	0.209	0.214	0.219	0.225
Avoided Water Marginal Rate	($/gallon)	0.008	0.008	0.008	0.008	0.008	0.008	0.008	0.008	0.008	0.008	0.008	0.008	0.008	0.008	0.008
Avoided Water Retail Rate	($/gallon)	0.008	0.008	0.008	0.008	0.008	0.008	0.008	0.008	0.008	0.008	0.008	0.008	0.008	0.008	0.008

ELECTRIC LINE LOSSES (Entered as a Multiplier)

Sector	Summer On Peak (%)	Summer Off Peak (%)	Winter On Peak (%)	Winter Off Peak (%)	Summer Demand	Winter Demand	T&D	Reserve Margin Multiplier
Residential	1.067	1.067	1.067	1.067	1.067	1.067	1.00	1.17
NonResidential	1.067	1.067	1.067	1.067	1.067	1.067	1.00	1.17

APPENDIX D: DEMAND RESPONSE ASSUMPTIONS

Measure	Assumptions	Value	Source
Direct Load Control (DLC) AC Switch	# of Control Units per Participant	1.14	2025 Big Rivers Saturation data; average number of AC units for those that have central AC
	Participant Annual Incentive - Res	$31/participant-year for summer only program	Puget Sound Energy 2023, Pacificorp 2023, BPA 2021, ComEd program, SCE program, Entergy AR program, Florida Power and Light program
	Participant Annual Incentive - C&I	$38/participant-year for summer only program	Puget Sound Energy 2023, Pacificorp 2023
	Annual Number of Control Hours	20	Assumes 16 events per year (5 summer/winter and 3 spring/fall), 4 hours per event. MISO LMR.
	Per Participant Load Reduction - Summer - Res	0.788 kW	BPA 2021, Puget Sound Energy 2023, Xcel Energy 2022
	Per Participant Load Reduction - Summer - C&I	1.65 kW	Puget Sound Energy 2023, BPA 2021
	Control Equipment Useful Life	10 years	Freeman, Sullivan & Co Cost Effectiveness of CECONY Demand Response Programs 2013; PA Act 129 Order 2013
	Utility Per Unit Equipment/ Labor Cost - Res	$230/new participant	Puget Sound Energy 2023, BPA 2021, Pacificorp 2023
	Utility Per Unit Equipment/ Labor Cost - C&I	$387/new participant	Puget Sound Energy 2023, BPA 2021, Pacificorp 2023
	Participant Share of Equipment/Labor Cost	$0	N/A
	One Time Incentive Towards Cost of Equipment	$28	Entergy AR program, Omaha Public Power District program
	O&M/Vendor Service Fees per Customer Res	$25/participant	Assumes DERMS vendor would run program. DLC AC/WH/SPP programs are cheaper than Evs/batteries. GDS estimate based on DERMS quote from Big Rivers of $350,000/year after initial setup.
	O&M/Vendor Service Fees per Customer C&I	$25/participant	Assumes DERMS vendor would run program. DLC AC/WH/SPP programs are cheaper than Evs/batteries. GDS estimate based on DERMS quote from Big Rivers of $350,000/year after initial setup.
	Participation Rate Res	11.50%	Average of studies: Pacificorp 2023, BPA 2021
	Participation Rate C&I	10%	Puget Sound Energy 2023, BPA 2018
	Saturation Res	90.6% with Central AC	2025 Big Rivers Saturation data
	Saturation C&I	72.2% with Central AC	CBECS data
DLC Thermostat	# of Control Units per Participant	1.14	2025 Big Rivers Saturation data; average number of AC units for those that have central AC
	Participant Annual Incentive - Res	$32/partcipant-year	Puget Sound Energy 2023, Pacificorp 2023, BPA 2021, Duke Energy 2020, Xcel Energy 2022, Eversource program, AES IN program, CenterPoint IN program, DTE Energy program, ConEdison program, Austin Energy program, SCE program, Entergy AR program, PEPCO program, Omaha Public Power District program
	Participant Annual Incentive - C&I	$54/participant-year	Puget Sound Energy 2023, Xcel Energy 2022, Entergy AR program, PEPCO program
	Annual Number of Control Hours	64	Assumes 16 events per year (5 summer/winter and 3 spring/fall), 4 hours per event. MISO LMR.
	Per Participant Load Reduction - Summer - Res	0.932 kW	Ameren MO Evaluation 2023, Xcel Energy 2022, MA Utilities DLC Evaluation 2019, PSC Oklahoma 2022, Pacificorp 2023, Puget Sound Energy 2023, BPA 2021, CenterPoint IN 2024, Ecobee 2020, PG&E 2021, NRECA 2021
	Per Participant Load Reduction - Winter - Res	1.61 kW	NRECA 2021, PG&E 2021, BPA 2021, Puget Sound Energy 2023
	Per Participant Load Reduction - Summer - C&I	1.949 kW	CenterPoint IN 2021, Xcel Energy 2022, Puget Sound Energy 2023, Pacificorp 2019
	Per Participant Load Reduction - Winter - C&I	2.542 kW	Puget Sound Energy 2023, Pacificorp 2019
	Control Equipment Useful Life	11 years	Illinois TRM v13
	Utility Per Unit Equipment/ Labor Cost	0	BYOT program, no equipment cost for utility
	Participant Share of Equipment/Labor Cost - Res	$130	Cost of Ecobee thermostat minus the one-time incentive to customer
	Participant Share of Equipment/Labor Cost - C&I	$102	Cost of Ecobee thermostat minus the one-time incentive to customer
	One Time Incentive Towards Cost of Equipment - Res	$60/new participant	ConEdison program, Austin Energy program, SCE program, Entergy AR program, PEPCO program, Omaha Public Power District program
	One Time Incentive Towards Cost of Equipment - C&I	$88/new participant	Entergy AR program, Xcel Energy program
	O&M/Vendor Service Fees per Customer Res	$25/participant	Assumes DERMS vendor would run program. DLC AC/WH/SPP programs are cheaper than Evs/batteries. GDS estimate based on DERMS quote from Big Rivers of $350,000/year after initial setup.
	O&M/Vendor Service Fees per Customer C&I	$25/participant	Assumes DERMS vendor would run program. DLC AC/WH/SPP programs are cheaper than Evs/batteries. GDS estimate based on DERMS quote from Big Rivers of $350,000/year after initial setup.
	Participation Rate Res	20%	Average of studies: Pacificorp 2023, BPA 2021
	Participation Rate C&I	14%	Pacificorp 2021, Xcel Energy 2022
	Saturation Res	90.6% with Central AC; 53.9% with electric space heating; 79% with wifi	2025 Big Rivers Saturation data
	Saturation C&I	70.3% with Central AC; 51% with Electric Space Heating	CBECS data
DLC Water Heater Switch	# of Control Units per Participant	1	
	Participant Annual Incentive - Res	$30/participant-year	Puget Sound Energy 2023, BPA 2021, Xcel Energy 2022, Pacificorp 2023, SCE program, Florida Power Light program, AES IN program
	Participant Annual Incentive - C&I	$30/participant-year	Pacificorp 2023
	Annual Number of Control Hours	64	Assumes 16 events per year (5 summer/winter and 3 spring/fall), 4 hours per event. MISO LMR.
	Per Participant Load Reduction - Summer - Res	0.39 kW	NREL 2022, BPA 2021, Puget Sound Energy 2023, CenterPoint IN 2023, Xcel Energy 2022, Pacificorp 2023
	Per Participant Load Reduction - Winter - Res	0.59 kW	NREL 2022, BPA 2021, Puget Sound Energy 2023, AES IN 2023, Xcel Energy 2022, Pacificorp 2023
	Per Participant Load Reduction - Summer - C&I	1.5	Pacificorp 2019
	Per Participant Load Reduction - Winter - C&I	1.5	Pacificorp 2019
	Control Equipment Useful Life	10 years	Freeman, Sullivan & Co Cost Effectiveness of CECONY Demand Response Programs 2013; PA Act 129 Order 2013
	Utility Per Unit Equipment/ Labor Cost	$330	Puget Sound Energy 2023, BPA 2021, Pacificorp 2023
	Participant Share of Equipment/Labor Cost	$0	
	One Time Incentive Towards Cost of Equipment	$0	
	O&M/Vendor Service Fees per Customer Res	$25/participant	Assumes DERMS vendor would run program. DLC AC/WH/SPP programs are cheaper than Evs/batteries. GDS estimate based on DERMS quote from Big Rivers of $350,000/year after initial setup.
	O&M/Vendor Service Fees per Customer C&I	$25/participant	Assumes DERMS vendor would run program. DLC AC/WH/SPP programs are cheaper than Evs/batteries. GDS estimate based on DERMS quote from Big Rivers of $350,000/year after initial setup.
	Participation Rate Res	20%	BPA 2021, NREL 2022, Puget Sound Energy 2023, PGE 2016
	Participation Rate C&I	20%	Assumed same as residential
	Saturation Res	69.20%	2025 Big Rivers Saturation data; saturation of electric storage WH
	Saturation C&I	50.40%	CBECS data
DLC Grid Enabled Water Heater	# of Control Units per Participant	1	
	Participant Annual Incentive - Res	$30/participant-year	Puget Sound Energy 2023, BPA 2021, Xcel Energy 2022, Pacificorp 2023, SCE program, Florida Power Light program, AES IN program
	Participant Annual Incentive - C&I	$30/participant-year	Pacificorp 2023
	Annual Number of Control Hours	64	Assumes 16 events per year (5 summer/winter and 3 spring/fall), 4 hours per event. MISO LMR.
	Per Participant Load Reduction - Summer - Res	0.43 kW	NREL 2022, BPA 2021, Puget Sound Energy 2023, Xcel Energy 2022, Pacificorp 2023
	Per Participant Load Reduction - Winter - Res	0.63 kW	NREL 2022, BPA 2021, Puget Sound Energy 2023, Xcel Energy 2022, Pacificorp 2023
	Per Participant Load Reduction - Summer - C&I	1.5	Pacificorp 2019
	Per Participant Load Reduction - Winter - C&I	1.5	Pacificorp 2019
	Control Equipment Useful Life	10 years	Freeman, Sullivan & Co Cost Effectiveness of CECONY Demand Response Programs 2013; PA Act 129 Order 2013
	Utility Per Unit Equipment/ Labor Cost	$50	Cost of control module. Puget Sound Energy 2023, BPA 2021, Pacificorp 2023
	Participant Share of Equipment/Labor Cost	$250	Assuming utility pays rebate for program participation. Costs for 50-gallon electric grid enabled water heaters range from $500-$800. Assumed $650 for mid-range WH.
	One Time Incentive Towards Cost of Equipment	$400	Xcel Energy 2022
	O&M/Vendor Service Fees per Customer Res	$25/participant	Assumes DERMS vendor would run program. DLC AC/WH/SPP programs are cheaper than Evs/batteries. GDS estimate based on DERMS quote from Big Rivers of $350,000/year after initial setup.
	O&M/Vendor Service Fees per Customer C&I	$25/participant	Assumes DERMS vendor would run program. DLC AC/WH/SPP programs are cheaper than Evs/batteries. GDS estimate based on DERMS quote from Big Rivers of $350,000/year after initial setup.
	Participation Rate Res	10%	BPA 2021, NREL 2022, Puget Sound Energy 2023, PGE 2016
	Participation Rate C&I	10%	Assumed same as residential
	Saturation Res	69.2% with electric storage WH; 79% with wifi	2025 Big Rivers Saturation data; saturation of electric storage WH
	Saturation C&I	50.40%	CBECS data
DLC Swimming Pool Pump	# of Control Units per Participant	1	
	Participant Annual Incentive	$12/participant-year	Duke Energy Florida program, Florida Power & Light program
	Annual Number of Control Hours	64	Assumes 16 events per year (5 summer/winter and 3 spring/fall), 4 hours per event. MISO LMR.
	Per Participant Load Reduction - Summer - Res	0.52 kW	EPRI 2017, Connected Pool Pump Market Assessment 2020
	Control Equipment Useful Life	10 years	Freeman, Sullivan & Co Cost Effectiveness of CECONY Demand Response Programs 2013; PA Act 129 Order 2013
	Utility Per Unit Equipment/ Labor Cost - Res	$141	Pacificorp 2023
	Participant Share of Equipment/Labor Cost	$0	
	One Time Incentive Towards Cost of Equipment	$0	
	O&M/Vendor Service Fees per Customer Res	$25/participant	Assumes DERMS vendor would run program. DLC AC/WH/SPP programs are cheaper than Evs/batteries. GDS estimate based on DERMS quote from Big Rivers of $350,000/year after initial setup.
	Participation Rate Res	20%	Assumes same participation rate as WH switch program

Measure Assumptions		Value	Source
	Saturation Res	18%	2022 Big Rivers Saturation data; saturation of electric pool pumps
Direct Load Control of EVs	Participant Annual Incentive	$39/participant-year	Eversource 2021, Puget Sound Energy 2023, Delaware Electric Cooperative program, Pacificorp 2023, BPA 2021, AES IN program
	Annual Number of Control Hours	64	Assumes 16 events per year (5 summer/winter and 3 spring/fall), 4 hours per event. MISO LMR.
	Per Participant Load Reduction - Summer - Res	0.295 kW	Eversource 2021, NRECA 2020, AES IN 2023, National Grid 2022, BPA 2021, Puget Sound Energy 2023, Pacificorp 2023
	Per Participant Load Reduction - Winter - Res	0.345 kW	Eversource 2021, AES IN 2023, Pacificorp 2023
	Per Participant Load Reduction - Summer - C&I	0.02 kW	Xcel Energy 2022
	Per Participant Load Reduction - Winter - C&I	0.03 kW	Xcel Energy 2022
	Control Equipment Useful Life	10 years	US DOE, Costs Associated with Non-Residential EV Supply Equipment, 2015
	Utility Per Unit Equipment/ Labor Cost	$0	Assumes level 2 charger controls EV- BYOD program
	Participant Share of Equipment/Labor Cost	$750 for new purchase; $0 for BYOD	Assumes installed cost of level 2 charger is $1000. Must have networked Level 2 charger to participate. NYSERDA 2022 white paper found that only 10% of residential EV chargers are already networked level 2 chargers. Remainder would need to be upgraded to participate.
	One Time Incentive Towards Cost of Equipment	$155	Eversource 2021, National Grid 2022, NRECA 2020, Delaware Electric Cooperative program, AES IN program
	O&M/Vendor Service Fees per Customer Res	$50/participant	Assumes DERMS vendor would run program. GDS estimate based on DERMS quote from Big Rivers of $350,000/year after initial setup.
	O&M/Vendor Service Fees per Customer C&I	$50/participant	Assumes DERMS vendor would run program. GDS estimate based on DERMS quote from Big Rivers of $350,000/year after initial setup.
	Participation Rate Res	20%	BPA 2021
	Participation Rate C&I	10%	GDS assumption of about 50% of MAP
	Saturation	100% of EVs	All EVs are eligible to participate
EV Time of Use Rate	Participant Annual Incentive	$0	No incentive for rate program
	Annual Number of Control Hours	1043	Assume 4 hrs/week day, year round
	Per Participant Load Reduction - Summer - Res	0.39 kW	SCE 2022, Xcel Energy 2022, ConEdison 2019, SDG&E 2021
	Per Participant Load Reduction - Winter - Res	0.325 kW	Xcel Energy 2022, SDG&E 2021
	Per Participant Load Reduction - Summer - C&I	0.02 kW	Xcel Energy 2022
	Per Participant Load Reduction - Winter - C&I	0.03 kW	Xcel Energy 2022
	Control Equipment Useful Life	10 years	US DOE, Costs Associated with Non-Residential EV Supply Equipment, 2015
	Utility Per Unit Equipment/ Labor Cost	$0	No cost to join rate
	Participant Share of Equipment/Labor Cost	$0	No cost to join rate
	One Time Incentive Towards Cost of Equipment	$0	No cost to join rate
	O&M/Vendor Service Fees per Customer Res	$10/participant-year	Puget Sound Energy 2023, Pacificorp 2023, BPA 2021
	O&M/Vendor Service Fees per Customer C&I	$10/participant-year	Puget Sound Energy 2023, Pacificorp 2023, BPA 2021
	Participation Rate Res	20%	Xcel Energy 2022
	Participation Rate C&I	20%	Assumed same as residential
	Saturation	100% of EVs	All EVs are eligible to participate
Time of Use Rate	Participant Annual Incentive	$0	N/A
	Annual Number of Control Hours	1043	Assume 4 hrs/week day, year round
	Per Participant Load Reduction - Summer - Res	8.60%	Average of studies: BPA 2021, Pacificorp 2023, PG&E 2023, Maryland Evaluation 2020, Dominion Energy 2022 Evaluation
	Per Participant Load Reduction - Winter - Res	3.60%	Average of studies: BPA 2021, Pacificorp 2023, PG&E 2023, Maryland Evaluation 2020, Dominion Energy 2022 Evaluation
	Per Participant Load Reduction - Summer - C&I	2.00%	Pacificorp 2023
	Per Participant Load Reduction - Winter - C&I	1.00%	Pacificorp 2023
	Control Equipment Useful Life	20 years	Useful life of smart meter. https://docs.cpuc.ca.gov/published/FINAL_DECISION/58362-07.htm#:~:text=The%20AMI%20system's%20useful%20life%20does%20not,is%20a%20reasonable%20forecast%20for%20the%20purposes
	Utility Per Unit Equipment/ Labor Cost	$0	No cost to join rate
	Participant Share of Equipment/Labor Cost	$0	No cost to join rate
	One Time Incentive Towards Cost of Equipment	$0	No cost to join rate
	O&M/Vendor Service Fees per Customer Res	$0	N/A, utility runs rate programs
	O&M/Vendor Service Fees per Customer C&I	$0	N/A, utility runs rate programs
	Participation Rate Res	10.2%	Duke Energy DR Study 2020, Average of next 10 top-performing opt-in TOU programs in EIA 861
	Participation Rate C&I	16.0%	Average of next 10 top-performing opt-in TOU programs in EIA 861
	Saturation Res	100%	All customers with a smart meter are eligible
	Saturation C&I	100%	All customers with a smart meter are eligible
Critical Peak Pricing Rate	Participant Annual Incentive	$0	N/A
	Annual Number of Control Hours	64	Assumes 16 events per year (5 summer/winter and 3 spring/fall), 4 hours per event. MISO LMR.
	Per Participant Load Reduction - Summer - Res	12.80%	Average of studies: Pacificorp 2023, Puget Sound Energy 2023, BPA 2021
	Per Participant Load Reduction - Winter - Res	7.70%	Average of studies: Pacificorp 2023, Puget Sound Energy 2023, BPA 2021
	Per Participant Load Reduction - Summer - C&I	7.90%	Average of studies: Pacificorp 2023, Puget Sound Energy 2023, BPA 2021
	Per Participant Load Reduction - Winter - C&I	6.00%	Average of studies: Pacificorp 2023, Puget Sound Energy 2023, BPA 2021
	Control Equipment Useful Life	20 years	Useful life of smart meter. https://docs.cpuc.ca.gov/published/FINAL_DECISION/58362-07.htm#:~:text=The%20AMI%20system's%20useful%20life%20does%20not,is%20a%20reasonable%20forecast%20for%20the%20purposes
	Utility Per Unit Equipment/ Labor Cost	$0	No cost to join rate
	Participant Share of Equipment/Labor Cost	$0	No cost to join rate
	One Time Incentive Towards Cost of Equipment	$0	No cost to join rate
	O&M/Vendor Service Fees per Customer Res	$0	N/A, utility runs rate programs
	O&M/Vendor Service Fees per Customer C&I	$0	N/A, utility runs rate programs
	Participation Rate Res	15%	Pacificorp 2023, Puget Sound Energy 2023, BPA 2021
	Participation Rate C&I	15%	Pacificorp 2023
	Saturation Res	100%	All customers with a smart meter are eligible
	Saturation C&I	100%	All customers with a smart meter are eligible
Peak Time Rebate	Participant Annual Incentive	$1/kWh saved	ComEd program, Ameren IL program, Delmarva Power program
	Annual Number of Control Hours	64	Assumes 16 events per year (5 summer/winter and 3 spring/fall), 4 hours per event. MISO LMR.
	Per Participant Load Reduction - Summer - Res	14%	Pacificorp 2023, PGE 2018 Pilot Study
	Per Participant Load Reduction - Winter - Res	8%	Pacificorp 2023, PGE 2018 Pilot Study
	Control Equipment Useful Life	20 years	Useful life of smart meter. https://docs.cpuc.ca.gov/published/FINAL_DECISION/58362-07.htm#:~:text=The%20AMI%20system's%20useful%20life%20does%20not,is%20a%20reasonable%20forecast%20for%20the%20purposes
	Utility Per Unit Equipment/ Labor Cost	$0	No cost to join rate
	Participant Share of Equipment/Labor Cost	$0	No cost to join rate
	One Time Incentive Towards Cost of Equipment	$0	No cost to join rate
	O&M/Vendor Service Fees per Customer Res	$0	N/A, utility runs rate programs
	Participation Rate Res	13%	Duke Energy DR Study 2020, Pacificorp 2023
	Saturation Res	100%	All customers with a smart meter are eligible
Battery Storage	# of Control Units per Participant	1	
	Participant Annual Incentive - Res	$400/participant	Massachusetts Energy Storage Demand Reduction Evaluation 2024, Xcel Energy 2022, Pacificorp 2023
	Participant Annual Incentive - C&I	$1500/participant	Based on incentive per kW for residential programs, for 11.25 kW C&I battery
	Annual Number of Control Hours	64	Assumes 16 events per year (5 summer/winter and 3 spring/fall), 4 hours per event. MISO LMR.
	Per Participant Load Reduction - Summer - Res	3 kW	Assumes utility could use 60% of 5kW residential battery
	Per Participant Load Reduction - Winter - Res	3 kW	Assumes utility could use 60% of 5kW residential battery
	Per Participant Load Reduction - Summer - C&I	11.25 kW	2017 SGIP Advanced Energy Storage Impact Evaluation. Peak demand reduction of 45% of rebated capacity for a 25 kW battery - Figure 4-36 of study.
	Per Participant Load Reduction - Winter - C&I	11.25 kW	2017 SGIP Advanced Energy Storage Impact Evaluation. Peak demand reduction of 45% of rebated capacity for a 25 kW battery - Figure 4-36 of study.
	Control Equipment Useful Life	10 years	Tesla Powerwall warranty
	Utility Per Unit Equipment/ Labor Cost	See below.	
	Participant Share of Equipment/Labor Cost - Res	Cost of residential battery is $15,479 in 2027 and decreases to $11,654 in 2045. Can assume a BYOB program where participant pays full cost and eligible pool of customers is small or could assume that utility pays for 25% of battery cost to incentivize customers to participate in program.	NREL 2024 cost forecast: https://atb.nrel.gov/electricity/2024/residential_battery_storage

Measure Assumptions		Value	Source
	Participant Share of Equipment/Labor Cost - C&I	Cost of 25 kW C&I battery is $230,495 in 2027 and decreases to $173,27 in 2045. Can assume a BYOB program where participant pays full cost and eligible pool of customers is small or could assume that utility pays for 25% of battery cost to incentivize customers to participate in program.	NREL 2024 cost forecast: https://atb.nrel.gov/electricity/2024/residential_battery_storage
	One Time Incentive Towards Cost of Equipment	See above.	
	O&M/Vendor Service Fees per Customer Res	$77/kW starting in 2027; decreases to $58/kW in 2045	NREL 2024 cost forecast: https://atb.nrel.gov/electricity/2024/residential_battery_storage
	O&M/Vendor Service Fees per Customer C&I	$43/kW starting in 2027; decreases to $33/kW in 2045	NREL 2024 cost forecast: https://atb.nrel.gov/electricity/2024/residential_battery_storage
	Participation Rate Res	50%	Xcel Energy 2022
	Participation Rate C&I	50%	Assumes same as residential
	Saturation Res	12% of customers with solar	LBL Tracking The Sun Report 2024
	Saturation C&I	8% of customers with solar	LBL Tracking The Sun Report 2024
Capacity Bidding	Participant Annual Incentive	$80/kW pledged/nominated per participant for year-round participation	Statewide California Capacity Bidding Evaluation 2021
	Annual Number of Control Hours	64	Assumes 16 events per year (5 summer/winter and 3 spring/fall), 4 hours per event. MISO LMR.
	C&I	25%	Average of studies: Statewide California Capacity Bidding Evaluation 2021, Pacificorp 2019; assumes day-ahead notification
	Per Participant Load Reduction Dispatched - Winter - C&I	25%	Average of studies: Statewide California Capacity Bidding Evaluation 2021, Pacificorp 2019; assumes day-ahead notification
	Nominated capacity compared to dispatched	150% of dispatched load	Statewide California Capacity Bidding Evaluation 2021
	Control Equipment Useful Life	20 years	Useful life of smart meter. https://docs.cpuc.ca.gov/published/FINAL_DECISION/58362-07.htm#:~:text=The%20AMI%20system's%20useful%20life%20does%20not,is%20a%20reasonable%20forecast%20for%20the%20purposes
	Utility Per Unit Equipment/ Labor Cost	$0	No equipment cost
	Participant Share of Equipment/Labor Cost	$0	No equipment cost
	One Time Incentive Towards Cost of Equipment	$0	No equipment cost
	Admin costs	$20/kW	Assume similar to Load Curtailment program
	O&M/Vendor Service Fees per Customer C&I	$70/kW	Pacificorp 2019
	Participation Rate C&I	21.5%	Pacificorp 2019
	Saturation C&I	100% of large C&I customers	All large C&I customers are eligible to participate.
Interruptible Rate	Participant Annual Incentive	$8/kW-month	Xcel Colorado program, PG&E program, BPA 2018, LADWP program, AES IN program, Entergy Louisiana program, Alliant Energy program, Unisource Arizona program
	Annual Number of Control Hours	64	Assumes 16 events per year (5 summer/winter and 3 spring/fall), 4 hours per event. MISO LMR.
	Per Participant Load Reduction - Summer - C&I	23%	Average of studies: Pacificorp 2023, Puget Sound Energy 2023, BPA 2021, PGE 2016
	Per Participant Load Reduction - Winter - C&I	23%	Average of studies: Pacificorp 2023, Puget Sound Energy 2023, BPA 2021, PGE 2016
	Control Equipment Useful Life	20 years	Useful life of smart meter. https://docs.cpuc.ca.gov/published/FINAL_DECISION/58362-07.htm#:~:text=The%20AMI%20system's%20useful%20life%20does%20not,is%20a%20reasonable%20forecast%20for%20the%20purposes
	Utility Per Unit Equipment/ Labor Cost	$10 per new kW pledged	BPA 2021, Puget Sound Energy 2023
	Participant Share of Equipment/Labor Cost	$0	No equipment cost
	One Time Incentive Towards Cost of Equipment	$0	No equipment cost
	Admin costs	$20/kW	BPA 2019, Snohomish County PUD
	O&M/Vendor Service Fees per Customer C&I	$20/kW	BPA 2021, Puget Sound Energy 2023
	Participation Rate C&I	19%	Pacificorp 2023, Xcel Energy 2022, BPA 2021, PG&E 2016
	Saturation C&I	100% of large C&I customers	All large C&I customers are eligible to participate.
Conservation Voltage Reduction (CVR)	Participant Annual Incentive	$0	Incentives are not typically paid to the participant
	Annual Number of Control Hours	64	Assumes 16 events per year (5 summer/winter and 3 spring/fall), 4 hours per event. MISO LMR.
	Per Participant Load Reduction - Summer - Res	1.70%	New Brunswick Power 2021, US DOE 2014
	Per Participant Load Reduction - Winter - Res	1.70%	New Brunswick Power 2021, US DOE 2014
	Per Participant Load Reduction - Summer - C&I	1.70%	New Brunswick Power 2021, US DOE 2014
	Per Participant Load Reduction - Winter - C&I	1.70%	New Brunswick Power 2021, US DOE 2014
	Control Equipment Useful Life	10-20 years	US DOE 2014
	Implementation costs	0	Big Rivers already has this capability
	Utility Per Unit Equipment/ Labor Cost	0	Big Rivers already has this capability
	Participant Share of Equipment/Labor Cost	$0	N/A
	One Time Incentive Towards Cost of Equipment	$0	Incentives are not typically paid to the participant
	O&M/Vendor Service Fees /Admin	$200,000/year	Includes support, software licensing, field verification, monitoring, analytics, etc.
	Participation Rate	100%	CVR would be applied at substation/feeder and all customers would experience voltage reduction automatically. Customers do not need to enroll in program.
	Saturation Res	100%	All customers are eligible
	Saturation C&I	100%	All customers are eligible
DR Generators	Participant Annual Incentive	$250/participant-year	DTE Energy program (https://www.generac.com/services-applications/grid-solutions-programs/detroit-dte/)
	Annual Number of Control Hours	64	Assumes 16 events per year (5 summer/winter and 3 spring/fall), 4 hours per event. MISO LMR.
	Per Participant Load Reduction - Summer - Res	50% of home's load	Assume that not all generators are whole-home generators and would only offset about half of the home's load
	Per Participant Load Reduction - Winter - Res	50% of home's load	Assume that not all generators are whole-home generators and would only offset about half of the home's load
	Control Equipment Useful Life	19 years	FEMA 2022 Generator Technical Review
	Utility Per Unit Equipment/ Labor Cost	0	Assumes customer already has generator
	Participant Share of Equipment/Labor Cost	0	Assumes customer already has generator
	One Time Incentive Towards Cost of Equipment	$100/new participant	DTE Energy program (https://www.generac.com/services-applications/grid-solutions-programs/detroit-dte/)
	O&M/Vendor Service Fees per Customer Res	$50/participant	Assumes DERMS vendor would run program. GDS estimate based on DERMS quote from Big Rivers of $350,000/year after initial setup.
	Participation Rate Res	5%	GDS Assumption
	Saturation Res	9.23%	2025 Big Rivers Saturation data; current saturation of whole house generators
General Program Costs (unless otherwise noted)	Implementation	$150,000 per program	Based on DERMS quote from Big Rivers of $500,000 for first year and $350,000/year after initial setup. Includes cost of DRMS set up, program design & engineering, integration with AMI
	Admin	$75,000/year	GDS Assumption. Can be split between similar programs. Internal admin at Big Rivers. Assumes DRMS vendor is assisting in running program.
	Marketing	$50/new participant	GDS Assumption. Includes outreach, education, and digital tools.
	Evaluation	$50,000 per program, evaluated every 2 years	GDS Assumption

Sources

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APPENDIX C

CONFIDENTIAL
DETAILED TRANSMISSION SYSTEM MAP

APPENDIX D

CONFIDENTIAL

TECHNICAL APPENDIX

APPENDIX E

CROSS REFERENCE TO 807 KAR 5:058

Appendix E
Cross-Reference to 807 KAR 5:058

Regulatory Citation	Regulatory Requirement	IRP Location
		Compliance Reference
807 KAR 5:058 Section 1 (1)	General Provisions. This administrative regulation shall apply to electric utilities under commission jurisdiction except a distribution company with less than $10,000,000 annual revenue or a distribution cooperative organized under KRS Chapter 279.	Not applicable to substantive IRP content
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.	Not applicable to substantive IRP content
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	On Sepember 16, 2026 Big Rivers submited Notice of Election of Use Electronic Filing Procedures. Because this proceeding is an electronic case, the utility is exempt from the hard-copy submission rules of 807 KAR 5:058 Section 1(3) pursuant to the Commission's mandate in *Electronic Emergency Docket Related to the Novel Coronavirus COVID-19*, Case No. 2020-00085, Order at 4–5 (July 22, 2021), which permanently eliminated the requirement to file physical copies of case documents.

Appendix E
Cross-Reference to 807 KAR 5:058

Regulatory Citation	Regulatory Requirement	IRP Location
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.	Not applicable to substantive IRP content
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:	Administrative requirement; not applicable to substantive IRP content
	5. Big Rivers Electric Corporation shall file thirty-three (33) months from the effective date; and	
	The schedule shall provide at such time as all electric utilities have filed integrated resource plans, the sequence shall repeat.	
807 KAR 5:058 Section 2 (1) (c)	The schedule shall remain in effect until changed by the commission on its own motion or on motion of one (1) or more electric utilities for good cause shown. Good cause may include a change in a utility's financial or resource conditions.	Administrative requirement; not applicable to substantive IRP content
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.	Commission procedural requirement
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.	Not applicable to substantive IRP content

Appendix E
Cross-Reference to 807 KAR 5:058

Regulatory Citation	Regulatory Requirement	IRP Location
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.	Not applicable to substantive IRP content
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.	The 2026 IRP includes footnotes that supplement this appendix by identifying locations where specific provisions of 807 KAR 5:058 are addressed.
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 1.1 (Overview) at Table 1.1(a)

Appendix E
Cross-Reference to 807 KAR 5:058

Regulatory Citation	Regulatory Requirement	IRP Location
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	Section 1.2 (Big Rivers, Its Members, Service Territory, Current Facilities and Planning Objectives) Section 6.2 (Objectives) Section 6.7.1 (Existing Resources) Section 6.12 (Conclusion)
807 KAR 5:058 Section 5 (2)	Description of models, methods, data, and key assumptions used to develop the results contained in the plan	Section 1.3 (IRP Summary) Chapter 3 Load Forecast Chapter 4 Demand-Side Management Chapter 6 Electrical Integration Analysis Technical Appendices: A Long-Term Load Forecast Report, B Demand-Side Management Potential Study, and D Technical Appendix

Appendix E
Cross-Reference to 807 KAR 5:058

Regulatory Citation	Regulatory Requirement	IRP Location
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 3 Load Forecast Appendix A Long-Term 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 1.3 (IRP Summary) Section 6.1 (Key Findings and Preferred Resource Strategy) Section 6.11 (IRP Preferred Resource Portfolio and Short-Term Action Plan) Section 9.1 (Action Plan Detail)
807 KAR 5:058 Section 5 (5)	Steps to be taken during the next three (3) years to implement the plan	Section 6.1.3 (Short-Term Action Plan) Section 6.11.2 (Short-Term Action Plan) Section 9.1 (Action Plan Detail)

Appendix E
Cross-Reference to 807 KAR 5:058

Regulatory Citation	Regulatory Requirement	IRP Location
807 KAR 5:058 Section 5 (6)	Discussion of key issues or uncertainties that could affect successful implementation of the plan.	Section 3.6 (Uncertainties) Section 5.8 (Environmental Study & Monitoring) Section 6.4 (Regulatory Environment) Section 6.5 (IRP Framework)
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 2 Significant Developments and Changes Since 2023 IRP Section 2.6 (Tabular Summary)
	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:	Chapter 3 Load Forecast Appendix A Long-Term Load Forecast Report
	(a) Residential heating;	n/a
	(b) Residential non-heating;	n/a

Appendix E
Cross-Reference to 807 KAR 5:058

Regulatory Citation	Regulatory Requirement	IRP Location
807 KAR 5:058 Section 7 (1) (a - g)	(c) Total residential (total of paragraphs (a) and (b) of this subsection);	Section 3.4 (Energy) Appendix A Long-Term Load Forecast Report, particularly at Section 3.1 (Residential Class)
	(d) Commercial;	Section 3.4 (Energy) Appendix A Long-Term Load Forecast Report, particularly at Section 3.2 (Commercial and Industrial Class)
	(e) Industrial;	Section 3.4 (Energy) Appendix A Long Term Load Forecast Report, particularly at Section 3.2 (Commercial and Industrial Class)
	(f) Sales for resale;	Section 3.4 (Energy) Appendix A Long-Term Load Forecast Report, particularly at Chapter 3 Energy Forecast Results

Appendix E
Cross-Reference to 807 KAR 5:058

Regulatory Citation	Regulatory Requirement	IRP Location
	(g) Utility use and other.	Section 3.4 (Energy) Appendix A Long-Term Load Forecast Repor, particularly at Chapter 3 Energy Forecast Results
	The utility shall also provide data at any greater level of disaggregation available.	Appendix A Long-Term Load Forecast Report
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:	Appendix A Long-Term Load Forecast Report, particular at Chapters 3 Energy Forecast Results and 4 Peak Demand
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 Long-Term Load Forecast Report, particular at Chapter 3 Energy Forecasts Results
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 Long-Term Load Forecast Report, particularly at Chapters 3 Energy Forecasts Results and 7 Weather Normalized Values

Appendix E
Cross-Reference to 807 KAR 5:058

Regulatory Citation	Regulatory Requirement	IRP Location
807 KAR 5:058 Section 7 (2) (c)	Recorded and weather-normalized coincident peak demand in summer and winter for the system	Appendix A Long-Term Load Forecast Report, particularly at Chapter 7 Weather Normalized Values
807 KAR 5:058 Section 7 (2) (d)	Total energy sales and coincident peak demand to retail and wholesale customers for which the utility has firm, contractual commitments	Section 3.4 (Energy) Appendix A Long-Term Load Forecast Repor, particularly at Chapters 3 Energy Forecasts Results and 4 Peak Demand
807 KAR 5:058 Section 7 (2) (e)	Total energy sales and coincident peak demand to retail and wholesale customers for which service is provided under an interruptible or curtailable contract or tariff or under some other nonfirm basis	Section 4.6.2 (Demand Response Program Options) Section 1.2.8 (Economic Development)
807 KAR 5:058 Section 7 (2) (f)	Annual energy losses for the system	Section 3.4 (Energy) Table 3.4 (a) (Total System Energy Summary) Appendix A Long-Term Load Forecast Report, particularly Chapter 10 Appendix

Appendix E
Cross-Reference to 807 KAR 5:058

Regulatory Citation	Regulatory Requirement	IRP Location
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 4 Demand-Side Management Appendix B Demand-Side Management Potential Study, particularly at Chapters 5 Energy Efficienty Program Potetial, 6 Demand Response Methodology, and 7 Demand Response Potential Appendix A, Long-Term Load Forecast at Section 1.3 (Native Forecast Summary) and Chapter 5 DSM Impact Scenario
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, particularly Chapter 10 Load Shape and Sorted Load Curve, Section 3.1.2 (Residential Use per Consumer Forecast), Chapter 9 Tracking Analysis and also Sections 1.3.1 (Monthly Peak Forecast) and 4.1 (Coincident Peak Demand)

Appendix E
Cross-Reference to 807 KAR 5:058

Regulatory Citation	Regulatory Requirement	IRP Location
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 Report, particularly Chapter 3 Energy Forecast Results and Chapter 6 Alernative System Forecasts and Uncertainty Analysis, and also Sections 1.3 (Native Forecast Summary) and 4.1 (Coincident Peak Demand)
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 Report, particularly Chapter 3 Energy Forecast Results
807 KAR 5:058 Section 7 (4) (b)	Summer and winter coincident peak demand for the system	Section 6.6 (Load Forecast) Appendix A Long-Term Load Forecast Report, particularly at Chapter 4 Peak Demand and Chapter 9 Tracking Analysis
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, particularly at Chapters 3 Energy Forecast Results and 4 Peak Demand

Appendix E
Cross-Reference to 807 KAR 5:058

Regulatory Citation	Regulatory Requirement	IRP Location
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	Chapter 4 Demand-Side Management, particularly at Section 4.6.2 (Demand Response Program Options) and Section 4.8 (DERMS Development Plan) Appendix B Demand-Side Management Potential Study,
807 KAR 5:058 Section 7 (4) (e)	Any other data or exhibits which illustrate projected changes in load or load characteristics	Section 1.2.7 (Big Rivers' Member Load and Load Growth) Appendix A Long-Term Load Forecast Report
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.	Procedrual filing requirement; not applicable to substantive IRP content
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, particularly at Chapter 8, Forecast Methodology

Appendix E
Cross-Reference to 807 KAR 5:058

Regulatory Citation	Regulatory Requirement	IRP Location
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, particularly at Sections 8.2 (Key Economic and Demographic Assumptions) through 8.4 (Forecast Development)
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, particularly at Sections 8.3 (Model Development, 8.4 (Forecast Development) and Chapter 10 Appendix
807 KAR 5:058 Section 7 (7) (d)	The plan shall include a complete description and discussion of the utility's treatment and assessment of load forecast uncertainty	Section 3.6 (Uncertainties) Appendix A Long-Term Load Forecast Report, particularly at Chapter 6 Alternative System Forecasts and Uncertainty Analysis and also Chapters 7 Weather Normalized Values and Chapter 9 Tracking Analysis
	The extent to which the utility's load forecasting methods and models explicitly address and incorporate the following factors:	

Appendix E
Cross-Reference to 807 KAR 5:058

Regulatory Citation	Regulatory Requirement	IRP Location
807 KAR 5:058 Section 7 (7) (e)	1. Changes in prices of electricity and prices of competing fuels;	Appendix A Long-Term Load Forecast Report, particularly at Chapter 8 Forecast Methodology
	2. Changes in population and economic conditions in the utility's service territory and general region;	Appendix A Long-Term Load Forecast Report, particularly at Chapter 3 Energy Forecast Results, Chapter 6 Alternative System Forecast and Uncertainty Analsysis, and Chapter 8 Forecast Metholody
	3. Development and potential market penetration of new appliances, equipment, and technologies that use electricity or competing fuels; 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 4.8 (DERMS Development Plan) Appendix B Demand-Side Management Potential Study, particularly at Chapters 5 -7

Appendix E
Cross-Reference to 807 KAR 5:058

Regulatory Citation	Regulatory Requirement	IRP Location
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	Appendix A Long-Term Forecast Report, particularly at Section 8.1 (Database Setup and Analysis) Section 2.1 (Changes to Load Forecast) Section 4.2.2 (Market Characterization) Section 4.8 (DERMS Development Plan)
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.	Chapter 4 Demand-Side Management, particularly at Section 4.2.2 (Market Characterization) and Section 4.8 (DERMS Development Plan) Appendix B Demand-Side Management Potential Study, particularly at Sections 1.2, 2.2, 2.3 and Chapters 5 through 8

Appendix E
Cross-Reference to 807 KAR 5:058

Regulatory Citation	Regulatory Requirement	IRP Location
	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 6 Electric Integration Analysis, particularly at Section 6.5 (IRP Framework) and Section 6.9 (Capacity Expansion Results) Chapter 9 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 6 Electric Integration Analysis, particularly at Sections 6.7.1 (Existing Resources), 6.7.5 through 6.7.9, and 6.8.6 Appendix D Technical Appendix

Appendix E
Cross-Reference to 807 KAR 5:058

Regulatory Citation	Regulatory Requirement	IRP Location
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 4 Demand-Side Management Chapter 6 Electric Integration Analysis, particularly at Section 6.8 (Model Inputs) and Section 6.7.2 (Demand Side Management Resources) Chapter 9 Action Plan Appendix B Demand-Side Management Potential Study Appendix D Technical Appendix
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 6 Electric integration Analysis, particularly at Sections 6.1 (Key Findings and Preferred Resource Strategy), 6.7.7 (Green Fuel Oil Backup), 6.7.9 (Reid CT Replacement Need), 6.8.6 (New Resource Options), and 6.9 (Capacity Expansion Results) Appendix D Technical Appendix

Appendix E
Cross-Reference to 807 KAR 5:058

Regulatory Citation	Regulatory Requirement	IRP Location
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 6 Electric Integration Analysis Section 4.8 (DERMS Development Plan) Appendix A Long Term Load Forecast Report, particularly at Section 2.2 (Distributed Generation Forecast) Appendix B Demand-Side Management Potential Study, particularly at Chapters 6 and 8 Appendix D Technical Appendix
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	Not applicable to substantive IRP content

Appendix E
Cross-Reference to 807 KAR 5:058

Regulatory Citation	Regulatory Requirement	IRP Location
807 KAR 5:058 Section 8 (3) (a)	A map of existing and planned generating facilities, transmission facilities with a voltage rating of sixty-nine (69) kilovolts or greater, indicating their type and capacity, and locations and capacities of all interconnections with other utilities. The utility shall discuss any known, significant conditions which restrict transfer capabilities with other utilities	Section 1.2.6 (Current Transmission System), including Confidential Figure 1.2.6(a) Section 6.7.1 (Existing Resources) Chapter 7 Transmission Planning Appendix C Confidential Detailed Tranmission System Map
	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 1.2.3 (Current Generation Facilities) Section 6.7.1 (Existing Resources) Section 6.9 (Capacity Expansion Results)

Appendix E
Cross-Reference to 807 KAR 5:058

Regulatory Citation	Regulatory Requirement	IRP Location
	2. Unit number(s);	Section 1.2.3 (Current Generation Facilities) Section 6.7.1 (Existing Resources) Section 6.9 (Capacity Expansion Results)
	3. Existing or proposed location;	Section 1.2.3 (Current Generation Facilities) Section 6.7.1 (Existing Resources) Section 6.9 (Capacity Expansion Results)
	4. Status (existing, planned, under construction, etc.);	Section 1.2.3 (Current Generation Facilities) Section 6.7.1 (Existing Resources) Section 6.9 (Capacity Expansion Results)

Appendix E
Cross-Reference to 807 KAR 5:058

Regulatory Citation	Regulatory Requirement	IRP Location
807 KAR 5:058 Section 8 (3) (b) (*1-11*)	5. Actual or projected commercial operation date;	Section 1.2.3 (Current Generation Facilities) Section 6.7.1 (Existing Resources) Section 6.9 (Capacity Expansion Results)
	6. Type of facility;	Section 1.2.3 (Current Generation Facilities) Section 6.7.1 (Existing Resources) Section 6.9 (Capacity Expansion Results)
	7. Net dependable capability, summer and winter;	Section 1.2.3 (Current Generation Facilities) Section 6.7.1 (Existing Resources) Section 6.9 (Capacity Expansion Results)
	8. Entitlement if jointly owned or unit purchase;	n/a

Regulatory Citation	Regulatory Requirement	IRP Location
	9. Primary and secondary fuel types, by unit;	Section 1.2.3 (Current Generation Facilities) Section 6.7.1 (Existing Resources) Section 6.9 (Capacity Expansion Results)
	10. Fuel storage capacity;	Section 1.2.3 (Current Generation Facilities) Section 6.7.7 (Green Fuel Oil Backup) Section 6.7.1 (Existing Resources) Section 6.9 (Capacity Expansion Results)
	11. Scheduled upgrades, deratings, and retirement dates	Section 6.7.1 (Existing Resources) Section 6.7.9 (Reid CT Replacement Need) Section 6.9 (Capacity Expansion Results) Chapter 9 Action Plan

Appendix E
Cross-Reference to 807 KAR 5:058

Regulatory Citation	Regulatory Requirement	IRP Location
	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 1.2.3(b) (Key Performance Indicators per IEEE Standards) Chapter 6 Electric Integration Analyis, including Section 6.7.1 (Existing Resources) and Section 6.8 (model inputs) Appendix D Technical Appendix
	b. Anticipated annual average heat rate;	Figure 1.2.3(c) (System Net Actual Heat Rate) and Table 1.2.3(a) (System Net Actual Heat Rate) Chapter 6 Electric Integration Analyis, including Section 6.7.1 (Existing Resources) and Section 6.8 (model inputs) Appendix D Tehnical Appendix

Appendix E
Cross-Reference to 807 KAR 5:058

Regulatory Citation	Regulatory Requirement	IRP Location
807 KAR 5:058 Section 8 (3) (b) (*12*)	c. Costs of fuel(s) per millions of British thermal units (MMBtu);	Chapter 6 Electric Integration Analyis, including Section 6.7.1 (Existing Resources) and Section 6.8 (model inputs) Appendix D Technical Appendix
	d. Estimate of capital costs for planned units (total and per kilowatt of rated capacity);	Chapter 6 Electric Integration Analysis, particularly at Section 6.7.1 (Existing Resources), Figure 6.8.6.1(a) and Figure 6.8.6.1(b) Appendix D Technical Appendix
	e. Variable and fixed operating and maintenance costs;	Chapter 6 Electric Integration Analyis, including Section 6.7.1 (Existing Resources) and Section 6.8 (model inputs) Appendix D Technical Appendix
	f. Capital and operating and maintenance cost escalation factors;	Chapter 6 Electric Integration Analyis, including Section 6.7.1 (Existing Resources) and Section 6.8 (model inputs) Appendix D Technical Appendix

Appendix E
Cross-Reference to 807 KAR 5:058

Regulatory Citation	Regulatory Requirement	IRP Location
	g. Projected average variable and total electricity production costs (in cents per kilowatt-hour).	Chapter 6 Electric Integration Analyis, including Section 6.7.1 (Existing Resources) and Section 6.8 (model inputs) Appendix D Technical Appendix
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 1.2.2 (RTO Membership/Bilateral Contracts) Section 1.2.8 (Economic Development) Chapter 3 Load Forecast Chapter 6 Electric Integration Analysis, including Section 6.7.1 (Existing Resources), confidential Figure 6.7.4(a) (Big Rivers' Summer Capacity Position) and confidential Figure 6.7.4(b) (Big Rivers' Winter Capacity Position) Appendix A Long-Term Load Forecast Report, particularly at Section 3.7 (Non-Member Energy Sales), 4.2 (Non-Member Capacity Sales) and 4.3 (Non-Coincident Peak Demand)

Appendix E
Cross-Reference to 807 KAR 5:058

Regulatory Citation	Regulatory Requirement	IRP Location
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	Chapter 6 Electric Integration Analysis particulary at Section 6.7.1 (Existing Resources) Appenidx A Long-Term Load Forecast Report, particularly at Section 2.2 (Distributed Generation Forecast) Appendix B Demand-Side Management Potential Study, particularly at Chapter , particularly at Section 8 (DERMS Devlopment Plan) Appendix D Technical Appendix
	For each existing and new conservation and load management or other demand-side programs included in the plan:	

Appendix E
Cross-Reference to 807 KAR 5:058

Regulatory Citation	Regulatory Requirement	IRP Location
	1. Targeted classes and end-uses;	Chapter 4 Demand-Side Management, particularly at Section 4.8 (DERMS Development Plan) Section 6.7.2 (Demand Side Management Resources) Appendix B Demand-Side Management Potential Study, particularly at Table 5-2 (Programs Evaluated in Study) and Chapters 3, 4, 6 and 7
	2. Expected duration of the program;	Chapter 4 Demand-Side Management, particularly at Section 4.8 (DERMS Development Plan) Section 6.7.2 (Demand Side Management Resources) Appendix B Demand-Side Management Potential Study

Appendix E
Cross-Reference to 807 KAR 5:058

Regulatory Citation	Regulatory Requirement	IRP Location
807 KAR 5:058 Section 8 (3) (e)	3. Projected energy changes by season, and summer and winter peak demand changes;	Chapter 4 Demand-Side Management,particularly at Section 4.8 (DERMS Development Plan) Section 6.7.2 (Demand Side Management Resources) Appendix B Demand-Side Management Potential Study
	4. Projected cost, including any incentive payments and program administrative costs; and	Chapter 4 Demand-Side Management,particularly at Section 4.8 (DERMS Development Plan) Section 6.7.2 (Demand Side Management Resources) Appendix B Demand-Side Management Potential Study

Appendix E
Cross-Reference to 807 KAR 5:058

Regulatory Citation	Regulatory Requirement	IRP Location
	5. Projected cost savings, including savings in utility's generation, transmission and distribution costs	Chapter 4 Demand-Side Management,particularly at Section 4.8 (DERMS Development Plan) Section 6.7.2 (Demand Side Management Resources) Appendix B Demand-Side Management Potential Study
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 6.7.4 (Current Summer and Winter Firm Capacity Position) Section 6.6 (Load Forecast) Section 6.9 (Capacity Expansion Results)

Appendix E
Cross-Reference to 807 KAR 5:058

Regulatory Citation	Regulatory Requirement	IRP Location
	2. Capacity from existing resources before consideration of retirements;	Section 6.7.4 (Current Summer and Winter Firm Capacity Position) Section 6.9 (Capacity Expansion Results)
	3. Capacity from planned utility-owned generating plant capacity additions;	Section 6.7.4 (Current Summer and Winter Firm Capacity Position) Section 6.7.7 (Green Fuel Oil Backup and 6.7.9 (Reid CT Replacement Need) Section 6.9 (Capacity Expansion Results)
	4. Capacity available from firm purchases from other utilities;	Section 6.7.4 (Current Summer and Winter Firm Capacity Position) Section 6.9 (Capacity Expansion Results)

Appendix E
Cross-Reference to 807 KAR 5:058

Regulatory Citation	Regulatory Requirement	IRP Location
	5. Capacity available from firm purchases from nonutility sources of generation;	Section 6.7.4 (Current Summer and Winter Firm Capacity Position) Section 6.9 (Capacity Expansion Results)
	6. Reductions or increases in peak demand from new conservation and load management or other demand-side programs;	Chapter 4 Demand-Side Management Section 6.7.4 (Current Summer and Winter Firm Capacity Position) Section 6.9 (Capacity Expansion Results) Appendix D Technial Appendix
	7. Committed capacity sales to wholesale customers coincident with peak;	Section 6.7.4 (Current Summer and Winter Firm Capacity Position) Section 6.9 (Capacity Expansion Results)

Appendix E
Cross-Reference to 807 KAR 5:058

Regulatory Citation	Regulatory Requirement	IRP Location
	8. Planned retirements;	Table 1.2.3(c) (Operating Characteristics of Existing Big Rivers Resources) Section 6.7.4 (Current Summer and Winter Firm Capacity Position) Section 6.7.9 (Reid CT Replacement Need) Section 6.5.5 (Green and Wilson Retirement Approaches) Section 6.9 (Capacity Expansion Results) Section 9.1 (Action Plan Detail)
	9. Reserve requirements;	Section 6.7.4 (Current Summer and Winter Firm Capacity Position) Section 6.7.3 (PRM and Coincidence Factor Assumptions) Section 6.9 (Capacity Expansion Results)

Appendix E
Cross-Reference to 807 KAR 5:058

Regulatory Citation	Regulatory Requirement	IRP Location
	10. Capacity excess or deficit;	Section 6.7.4 (Current Summer and Winter Firm Capacity Position) Section 6.1.1 (Key Findings) Section 6.9 (Capacity Expansion Results)
	11. Capacity or reserve margin.	Section 6.7.4 (Current Summer and Winter Firm Capacity Position) Section 6.9 (Capacity Expansion Results)
	On planned annual generation:	
	1. Total forecast firm energy requirements;	Section 6.6 (Load Forecast) Section 6.9 (Capacity Expansion Results)

Appendix E
Cross-Reference to 807 KAR 5:058

Regulatory Citation	Regulatory Requirement	IRP Location
807 KAR 5:058 Section 8 (4) (b)	2. Energy from existing and planned utility generating resources disaggregated by primary fuel type;	Section 6.7.5 (Current Annual Generation Position) Section 6.9 (Capacity Expansion Results) Section 6.10.1 (Scenario Analysis Results) Appendix D Technial Appendix
	3. Energy from firm purchases from other utilities;	Section 6.9 (Capacity Expansion Results) Section 6.10.1 (Scenario Analysis Results)
	4. Energy from firm purchases from nonutility sources of generation; and	Section 6.9 (Capacity Expansion Results) Section 6.10.1 (Scenario Analysis Results) Appendix D Technial Appendix

Appendix E
Cross-Reference to 807 KAR 5:058

Regulatory Citation	Regulatory Requirement	IRP Location
	5. Reductions or increases in energy from new conservation and load management or other demand-side programs	Chapter 4 Demand-Side Managementparticularly at Section 4.8 (DERMS Development Plan) Section 6.9 (Capacity Expansion Results) Appendix B Demand-Side Management Potential Study Appendix D Technial Appendix
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.	Chapter 6 Electric Integration Analysis, particularly at Section 6.1.2 (Preferred Resource Portfolio) and Section 6.9 (Capacity Expansion Results)
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 6 Electric Integration Analysis, particularly at Section 6.5 (IRP Framework) and Section 6.8 (Model Inputs)

Appendix E
Cross-Reference to 807 KAR 5:058

Regulatory Citation	Regulatory Requirement	IRP Location
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 6 Electric Integration Analysis, particularly at Section 6.5 (IRP Framework) and Section 6.8 (Model Inputs)
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 6 Electric Integration Analysis, particularly at Section 6.5 (IRP Framework), Section 6.8 (Model Inputs) and Section 6.9 (Capacity Expansion Results)
807 KAR 5:058 Section 8 (5) (d)	The resource assessment and acquisition plan shall include a description and discussion of: Criteria used in determining the appropriate level of reliability and the required reserve or capacity margin, and discussion of how these determinations have influenced selection of options	Section 2.4 (Significant Changes - MISO) Chapter 6 Electric Integration Analysis, particularly at Section 6.7.3 (PRM and Coincidence Factor Assumptions), Section 6.5 (IRP Framework), Section 6.6 (Load Forecast), Section 6.7.4 (Current Summer and Winter Firm Capacity Position) and Section 6.8 (Model Inputs) Chapter 8 Resource Adequcy and Planning

Appendix E
Cross-Reference to 807 KAR 5:058

Regulatory Citation	Regulatory Requirement	IRP Location
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	Appendix A Long-Term Load Forecast Report particularly at Section 8.1 (Database Setup and Analyses) Section 3.8 (Model Development) Chapter 4 Demand-Side Managementparticularly at Section 4.8 (DERMS Development Plan) Section 6.5 (IRP Framework) Section 6.8 (Model Inputs) Appendix B Demand-Side Management Potential Study, particular at Section 1.2,2.2, 2.3 and Chapters 6 through 8
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 5 Environmental Section 6.4 (Regulatory Environment) Section 6.5 (IRP Framework) Section 6.8 (Model Inputs)

Appendix E
Cross-Reference to 807 KAR 5:058

Regulatory Citation	Regulatory Requirement	IRP Location
807 KAR 5:058 Section 8 (5) (g)	The resource assessment and acquisition plan shall include a description and discussion of: Consideration given by the utility to market forces and competition in the development of the plan. Technical discussion, descriptions and supporting documentation shall be contained in a technical appendix	Section 2.4 (Significant Changes - MISO) Section 2.5 (Market Trends Summary) Section 6.5 (IRP Framework) Appendix B Demand-Side Management Potential Study, particularly at Section 2.2 throught 2.4
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 6.10 (IRP Results) Appendix D 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 6.8.1 (Discount Rate and Inflation Assumptions) Section 6.10 (IRP Results)
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 6.10 (IRP Results) Appendix D Technical Appendix

Appendix E
Cross-Reference to 807 KAR 5:058

Regulatory Citation	Regulatory Requirement	IRP Location
807 KAR 5:058 Section 9 (4)	The integrated resource plan shall, at a minimum, include and discuss the following financial information: Average system rates (revenues per kilowatt hour) by year	Section 6.10 (IRP Results) Table 9(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	Not applicable to substantive IRP content
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	Not applicable to substantive IRP content
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	Not applicable to substantive IRP content
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	Not applicable to substantive IRP content
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	Not applicable to substantive IRP content

APPENDIX F

CROSS-REFERENCE TO 2023 IRP STAFF RECOMMENDATIONS

Appendix F
Cross-Reference to Staff's 2023 IRP Staff Recommendations

Recommendation Category	Staff Recommendation	2026 IRP Reference
Load Forecast	In the future, BREC should provide more detailed explanations regarding the manipulation of the data and the calculations ultimately used in forecast calculations within the IRP as well as clear explanations for any inconsistencies between tables. For example, the IRP would have benefited from having the table provided to Commission Staff in BREC's response to Staff's First Request, Item 9, as well as an explanation as to the BREC CP to MISO CP. Furthermore, BREC should define all terms, such as BREC CP to MISO CP, that are not common to the industry.	Chapter 3 Load Forecast, particularly at Table 3.4(a), Section 3.1 (Load Forecast Introduction) Section 3.3 (Non-Coincident Peak) and Section 3.7 (Forecast Development) Section 6.6 (Load Forecast) Section 6.7.3 (PRM and Coincidence Factor Assumptions) Appendix G Acronyms Listing
Load Forecast	For the next IRP, BREC should ensure that its load forecasts are based on realistic assumptions that reflect its intentions. In addition, given BREC's preferred portfolio in the present case, additional scenarios should have been run exploring what combination of resources would be necessary to satisfy its Non-Member contract customers, as well as its actual peak demand.	Chapter 3 Load Forecast Section 1.2.2 (RTO Membership / Bilateral Contracts) Chapter 6 Electric Integration Analysis, particularly at Section 6.6 (Load Forecast) and Section 6.7.3 (PRM and Coincidence Factor Assumptions) Appendix A Long-Term Load Forecast Report

Appendix F
Cross-Reference to Staff's 2023 IRP Staff Recommendations

Recommendation Category	Staff Recommendation	2026 IRP Reference
DSM	Moving forward, Commission Staff expects BREC to fully utilize the DSM MPS and carefully review and evaluate the study findings. Staff recommends that BREC develop a plan to implement DSM and EE programs that BREC has identified as being cost-effective and meet targets for BREC's energy savings and demand reductions goals in the future. BREC has not shown any amount of effort into creating DSM/EE programs that were found cost-effective and result in energy-savings in the DSM MPS. Commission Staff notes that should a minimal capacity deficit arise, DSM programs are a unique and cost-effective way to reduce energy consumption for its customers so that BREC would have the opportunity to meet its native load with its own generation, rather having to purchase additional energy from the MISO market and incurring unnecessary costs.	Chapter 4 Demand-Side Management, particularly at Section 4.8 (DERMS Development Plan) Chapter 6 Electric Integration Analysis, particularly at Section 6.1.3 (Short-Term Action Plan) and Section 6.7.2 (Demand Side Management Resources) Appendix B Demand-Side Management Potential Study
Record Keeping	For the next IRP, BREC should ensure that its witnesses are familiar with and able to discuss in detail the reasoning supporting all assumptions and recommendations.	Noted Not addressed through IRP content; applicable to future proceeding activities
Discovery	Be prepared to re-run modeling simulations as required by Commission Staff.	Noted Not addressed through IRP content; applicable to future proceeding activities

Appendix F
Cross-Reference to Staff's 2023 IRP Staff Recommendations

Recommendation Category	Staff Recommendation	2026 IRP Reference
Construction and Compliance Timelines	Future modeling should include an assumption that retirements and new generation construction not be permitted to be selected by the model in years that BREC cannot feasibly comply with retirement statutes and still add interconnected replacement generation. Senate Bill 349 (which was not enacted until after the IRP was filed) adds time to the retirement timeline. Since the regulatory approval timeline for a retirement and site compatibility and CPCN approval for capacity replacement construction has increased, BREC would be unlikely to complete the retirement, construction of replacement generation, and interconnection process within the time frame included in its Base Case Portfolio. BREC should state in its IRP the estimated timeline for construction and the bases for the time frames used.	Section 1.3 (IRP Summary) Chapter 6 Electric Integration Analysis, particularly at Section 6.8.6 (New Resource Options), Section 6.5.5 (Green and Wilson Retirement Approaches) and 6.7.9 (Reid CT Replacement Need) Section 9.1 Action Plan Detail Appendix D Technical Appendix
Modeling and Assumptions – Base Case and Six Scenarios	For long range planning purposes, if BREC knows that no co-generation partner has been obtained when conducting its IRP analyses, BREC should (a) include a discussion of what it intends to do with the excess capacity as a part of a scenario run that assumes a co-generation partner is obtained and (b) conduct another scenario run that assumes no co-generation partner is obtained and there is no need for a relatively larger generation unit. A *priori* assumptions regarding the selection of and timing of generation technologies being added or retired should be avoided unless mandated by pending or recent enforceable regulations or for which the utility has committed for retirement in a given year. For modeling purposes, regulations being challenged in court should be modeled in scenario analyses, but not ignored as if they did not exist. If such assumptions are made, the model should be permitted to select addition or retirement of any generation technologies in any year. The model should consider the useful lives of generation resources, fuel costs, and any other costs or benefits beyond the 15-year planning horizon. If capacity limits are placed on a resource, BREC should explain the basis for those limits.	Chapter 6 Electric Integration Analysis, particularly at Section 6.2.1 (Planning Horizon), Section 6.8.6 (New Resource Options), Section 6.8.7 (New Resource Accreditation) and Section 6.8.8 (Renewable Resource Development Limits) Appendix D Technical Appendix

Appendix F
Cross-Reference to Staff's 2023 IRP Staff Recommendations

Recommendation Category	Staff Recommendation	2026 IRP Reference
Explanation of Contingencies	Unless the model predicts an economic benefit to purchasing capacity, its BREC's modeled portfolios should attempt to meet net reserve margin requirements via owned generation. The net cost of any expected purchases or sales of capacity based on seasonal capacity shortfalls or surplus should be represented in the IRP. If a contingency, such as renewal of Non-Member sales, has a significant impact on load forecast, BREC should indicate how it will respond if the plan may result in a capacity shortfall or surplus.	Chapter 6 Electric Integration Analysis, particularly at Section 6.7.5 (Current Annual Generation Position) and Section 6.9 (Capacity Expansion Results) Appendix D Technical Appendix
Explanation of Model Selections	When the portfolio selection and scenario evaluation analyses produce results that seem counterintuitive or unexpected, BREC should provide an explanation of those results. In addition, BREC should strive to be more precise in describing and explaining assumptions pertaining to individual potential resources. The IRP should include the terms of loan forgiveness for the PACE Solar and Storage projects to explain why a federally subsidized program was not selected under most scenarios.	Chapter 6 Electric Integration Analysis, particularly at Section 6.8 (Model Inputs) Appendix D Technical Appendix

Appendix F
Cross-Reference to Staff's 2023 IRP Staff Recommendations

Recommendation Category	Staff Recommendation	2026 IRP Reference
Environmental Compliance	BREC should either complete such an analysis or provide more detailed information about how it selected the carbon dispatch adder costs sensitivities. Whether using adder cost sensitivities or carbon capture and other compliance cost estimates, retirement of Wilson Station should be permitted by the model. If BREC is making decisions based on an estimated cost of $4 billion, the IRP should include the basis for this estimate in future IRPs.	Chapter 6 Electric Integration Analysis, particularly at Section 6.2.1 (Planning Horizon), Section 6.8.5 (Carbon Tax), Section 6.8.6 (New Resource Options), and Section 6.8.7 (New Resource Accreditation) Appendix D Technical Appendix
Environmental Compliance	Since BREC included the PACE Solar and Storage projects for its Base Portfolio even though it was not selected under most scenarios, Commission Staff does not necessarily take issue with the methodology for including compliance costs. However, BREC should include more information on how environmental compliance informed its decision-making at the portfolio selection stage. BREC should also clarify the purpose of the Aggressive Carbon Reduction Portfolio.	Chapter 5 Environmental Chapter 6 Electric Integration Analysis, particularly at Section 6.4 (Regulatory Environment) and Section 6.5 (IRP Framework) Appendix D Technical Appendix

APPENDIX G

ACRONYMS LISTING

WITH DEFINITIONS OF SELECT TERMS

Acronym / Term	Definition	Notes
AAR	Ambient Adjusted Ratings	
ACE	Affordable Clean Energy Rule	
ACEEE	American Council for An Energy-Efficient Economy	
ACES	Alliance For Cooperative Energy Services Power Marketing, LLC	ACES supported development of the 2026 IRP through resource planning and market expertise
AEO	Annual Energy Outlook	
AERO	Aeroderivative Natural Gas Turbine	
AI	Artificial Intelligence	
ARM	Anticipated Reverse Margin	
ATC	Around-the-Clock	
BART	Best Available Retrofit Technology	
Bcf	Billion Cubic Feet	
BES	Bulk Electric System	
BREC/Big Rivers/The Company	Big Rivers Electric Corporation	
BSER	Best System of Emissions Reductions	
BTU	British Thermal Unit	
C&I	Commercial And Industrial	
CAA	Clean Air Act	
CAIR	Clean Air Interstate Rule	
CAPEX	Capital Expenditures	
CBECS	Commercial Buildings Energy Consumption Survey	
CC	Combined Cycle	
CCR	Coal Combustion Residuals	
CCRMU	Coal Combustion Residuals Management Unit	
CCS	Carbon Capture And Sequestration	
CEMS	Continuous Emissions Monitoring Systems	
CEO	Chief Executive Officer	
CFR	Code Of Federal Regulations	
CIL/CEL	Capacity Import Limit/Capacity Export Limit	

Clearspring	Clearspring Energy Advisors, LLC	Authors of Appendix A Long-Term Load Forecast Report
COD	Commercial Operation Date	
CONE	Cost of New Entry	
CP	Coincident Peak. Three CP measures are referenced in this IRP: (1) **Member Coincident Peak,** the demand of an individual Member Owner at the time of the Big Rivers system peak; (2) **Big Rivers Coincident Peak**, the maximum demand on the Big Rivers system; and (3) **Big Rivers MISO Coincident Peak**, Big Rivers' demand at the time of the applicable MISO system peak, which is used for capacity planning purposes	The term CP may refer to different peak-demand measures used for load forecasting and resource planning. To distinguish among these measures, this IRP separately identifies Member CP, Big Rivers CP, and Big Rivers MISO CP
CPCN	Certificate of Public Convenience and Necessity	
CPF	Coincidental Peak Factor	
CPP	Clean Power Plan	
CRL	Combustion Residual Leachate	
CSAPR	Cross-State Air Pollution Rule	
CT	Combustion Turbine	
CVR	Conservation Voltage Reduction	
DEER	Database For Energy Efficient Resources	
DEHV	Daviess County Extra-High Voltage	
DERMS	Distributed Energy Resource Management System	
DLC	Direct Load Control	
DLOL	Direct Loss of Load	
DOE	Department of Energy	
DR	Demand Response	
DSM	Demand Side Management	
ECP	Environmental Compliance Plan	

EGU	Electric Generating Unit	
EHV	Extra-High Voltage	
EIA	Energy Information Administration	
ELG	Effluent Limitations Guidelines	
EM&V	Evaluation, Measurement And Verification	
EnCompass	Long-Term Capacity Expansion and Production Cost Simulation Model	ACES utilized EnCompass to develop the IRP
EPA	Environmental Protection Agency	
ES	Environmental Surcharge	
FAC	Fuel Adjustment Clause	
FER	Facility Evaluation Report	
FERC	Federal Energy Regulatory Commission	
FGD	Flue Gas Desulphurization	
FIP	Federal Implementation Plan	
FPM	Filterable Particulate Matter	
G&T	Generation and Transmission	
GCI	General Commercial and Industrial	
GDS	GDS Associates, Inc.	Authors of Appendix B Demand-Side Potential Study
GHG	Greenhouse Gas	
GIA	Generator Interconnection Agreement	
GRP	Gross Regional Product	
GW	Gigawatt	
GWh	Gigawatt-Hour	
HAP	Hazardous Air Pollutant	
HCI	Hydrogen Chloride	
HF	Hydrogen Fluoride	
Hg	Mercury	
HMI	Human-Machine Interface	
HMP&L	Henderson Municipal Power & Light	Municipal utility associated with Station Two
HVAC	Heating, Ventilation, And Air Conditioning	

ICAP	Installed Capacity	
IEEE	Institute of Electrical and Electronics Engineers	
IMM	Independent Market Monitor	
IRA	Inflation Reduction Act	
IRP	Integrated Resource Plan	
ISAC	Intermediate Seasonal Accredited Capacity	
ITC	Investment Tax Credit	
JPEC	Jackson Purchase Energy Corporation	A Member-Owner Headquartered in Paducah, KY
KAR	Kentucky Administrative Regulations	
KDAQ	Kentucky Division for Air Quality	
KDWM	Kentucky Division of Waste Management	
Kenergy	Kenergy Corp	A Member-Owner Headquartered In Henderson, KY
KRS	Kentucky Revised Statutes	
kV	Kilovolt	
kW	Kilowatt	
kWh	Kilowatt-Hour	
KY PSC	Kentucky Public Service Commission	
lb.	Pound	
LCOE	Levelized Cost of Energy	
LIC	Large Industrial Customer	
LLC	Limited Liability Company	
LMR	Load Modifying Resource	
Load MWh	Load Megawatt-Hours	
LOLE	Loss Of Load Expectation	
LRTP	Long Range Transmission Plan	
LRZ	Local Resource Zone	MISO-defined geographic area used for resource adequacy planning and capacity market administration.
LSE	Load-Serving Entity	

LSI	Legacy Coal Combustion Residuals Surface Impoundment	
MACT	Maximum Achievable Control Technology	
MATS	Mercury And Air Toxics Standards	
MCRECC	Meade County Rural Electric Cooperative Corporation	A Member-Owner Headquartered in Brandenburg, KY
MECS	Manufacturing Energy Consumption Survey	
MISO	Midcontinent Independent System Operator, Inc.	Regional transmission organization of which Big Rivers is a member
MM	Million	
MMBtu	Million British Thermal Units	
MPS	Market Potential Study	
MSRM	Member Rate Stability Mechanism	
MTEP	MISO Transmission Expansion Plan	
MVAR	Megavolt-Ampere Reactive	
MW	Megawatt	
MWh	Megawatt-Hour	
NAAQS	National Ambient Air Quality Standards	
NAG	Net Actual Generation	
NAPDR	National Action Plan On Demand Response	
NCP	Non-Coincident Peak	The IRP refers to the **Member Non-Coincident Peak,** which is the Annual Demand of an Individual Big Rivers Member, Without Regard to When the Other Members or the Big Rivers System Peak Occurs.
NEEP	Northeast Energy Efficiency Partnership	

NERC	North American Electric Reliability Corporation	
Net CONE	Net Cost Of New Entry	
NewERA	Empowering Rural America Program	
NGCC	Natural Gas Combined Cycle	
NOx	Oxides Of Nitrogen	
NPDES	National Pollutant Discharge Elimination System	
NREL	National Renewable Energy Laboratory	
NSPS	New Source Performance Standards	
O&M	Operations And Maintenance	
OBBB	One Big Beautiful Bill	
OBBBA	One Big Beautiful Bill Act	
OMU	Owensboro Municipal Utilities	
OPGW	Optical Ground Wire	
P5	Fifth Percentile Stochastic Cost Outcome	
P95	Ninety-Fifth Percentile Stochastic Cost Outcome	
PCT	Participant Cost Test	
PM	Particulate Matter	
PPA	Power Purchase Agreement	
PRA	Planning Resource Auction	
PRM	Planning Reserve Margin	
PRMR	Planning Reserve Margin Requirement	
PTC	Production Tax Credit	
PURPA	Public Utility Regulatory Policies Act	
PVrr	Present Value of Revenue Requirements	
PY	Planning Year	
Q4	Fourth Quarter	
RA	Resource Adequacy	
RBDC	Reliability-Based Demand Curve	
RCRA	Resource Conservation and Recovery Act	
RDS	Rural Delivery Service	

RECS	Residential Energy Consumption Survey	
REHV	Reid Extra-High Voltage	
RFP	Request For Proposals	
RFI	Request for information	
RHR	Regional Haze Rule	
RICE	Reciprocating Internal Combustion Engine	
RTO	Regional Transmission Organization	
RTR	Risk and Technology Review	
SAC	Seasonal Accredited Capacity	
SAE	Statistically Adjusted End-Use	
SEPA	Southeastern Power Administration	
SERC	Southeast Electric Reliability Corporation	
SIP	State Implementation Plan	
SLM	Smelter Loss Mitigation	
SMR	Small modular reactor	
SO2	Sulfur dioxide	
SPP	Southwest Power Pool	
SSI	Statistically Significant Increase	
ST	Steam turbine	
T&D	Transmission and Distribution	
TIER	Times Interest Earned Ratio	
TOC	Transmission Operation Center	
TOU	Time of Use	
TRC	Total Resource Cost	
TVA	Tennessee Valley Authority	
UCAP	Unforce Capacity	
UCT	Utility Cost Test	
VOLL	Value of Lost Load	
VP	Vice President	
WACC	Weighted Average Cost of Capital	
WFGD	Wet flue gas desulfurization	
WTP	Willingness to participate	
ZRC	Zonal Resource Credit	

APPENDIX H

FIGURES AND TABLES LISTING

APPENDIX H - FIGURES AND TABLES LISTING

Figure Number	Figure Name	Section Reference
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