COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of*:*

ELECTRONIC 2023 INTEGRATED RESOURCE	**)**	**CASE NO.**
PLAN OF BIG RIVERS ELECTRIC CORPORATION	**)**	**2023-00310**

BIG RIVERS ELECTRIC CORPORATION'S
RESPONSES TO COMMISSION STAFF'S
SUPPLEMENTAL REQUEST FOR INFORMATION

Big Rivers Electric Corporation ("Big Rivers" or the "Company") by counsel, files its responses to Commission Staff's Supplemental Request for Information, issued in the above-captioned case on January 26, 2024.

FILED: February 16, 2024

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

REQUEST NO. 2-1: ***Refer to BREC's 2023 Integrated Resource Plan (IRP), Section 5.1.1, page 76. Provide the large industrial load growth that BREC is going to expect. Include in response the companies and the MW load requirement of the companies.***

RESPONSE: Big Rivers' 2023 IRP, Appendix A, page 41 shows the Direct Serve class MWh growth. Big Rivers' 2023 IRP, Appendix A, page 49 shows the Direct Serve class coincident peak ("CP") MW growth. The load growth in the Direct Serve class comes mostly from Pratt Paper (KY), LLC ("Pratt Paper"), Blockware Mining, Domtar Paper, and Nucor Corporation.

Witness: Terry Wright, Jr.

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

REQUEST NO. 2-2: ***Refer to IRP, Section 5.2, pages 77-78.***

a. ***Explain why BREC decided to use $1 million for the program scenario.***

b. ***Provide BREC's budgeting and actual amount for each of its DSM/EE programs that are in its portfolio. Include in the response BREC's total DSM/EE portfolio program costs.***

RESPONSE:

a. This amount is consistent with prior IRP analysis. For the last 5 iterations of the DSM Potential Study Big Rivers has evaluated a $1 million DSM/EE budget to provide consistency for Big Rivers and our Member Cooperatives' consideration.

b. Big Rivers currently has one pilot DSM program in its portfolio. The DSM-14 Low-Income Weatherization Support Program has a current annual budget of $100,000. There was no activity in this program in 2023 and therefore no cost associated with it.

Witness: Russell L. Pogue

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

REQUEST NO. 2-3: ***Refer to IRP, Section 5.2, Table 5.2, pages 80-81.***

a. Provide a TRC Test Ratio with a Potential Program at $500,000.

b. Explain why the residential section sector received less of the annual funding scenario than the non-residential sector.

c. Provide BREC's residential and non-residential annual MW savings from its DSM/EE programs.

RESPONSE:

a. The TRC under a funding scenario with a $500,000 annual spend would be nearly identical to the $1 million annual budget since the Program Potential approach is scaling up the levelized end-use savings costs to meet the selected budget.

i. TRC (Total) = 3.1

ii. TRC (Residential) = 2.4

iii. TRC (Non-Residential) = 3.6

b. In the Program Potential scenario, each end-use category for the residential and non-residential sectors is assigned a levelized cost per kWh and measure life derived from the individual measures that passed the Achievable Potential phase, in lieu of specific programs being designed. These were then scaled up to a $1 million annual budget. The non-residential sector receiving more budget implies that the cost of energy saving measures in the non-residential sector was lower than in the residential sector. If Big Rivers were to budget $1 million annually for DSM

savings, it would most likely focus on designing programs featuring a subset of the most cost-effective measures, informed by other factors as well (such as targeting lower income members or increasing insulation/air-sealing).

c. Please refer to Appendix B, Big Rivers 2023 IRP, Demand-Side Management Potential Study, sections 3 and 4 for all tables presenting the kWh and kW estimated savings for the potential scenarios. To the extent this request seeks information related to Big Rivers' current programs, please see Big Rivers' Rresponse to Commission Staff's Request No. 2-22.

Witness: Joshua Hoyt (Clearspring Energy Advisors, LLC)

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

REQUEST NO. 2-4: ***Refer to IRP, Section 5.5, pages 85-86. Explain what efforts BREC is actively undertaking to limit customer usage and provide necessary customer education to assist in reducing usage. Include in the response how BREC attempts to maximize customer demand response for its DSM/EE programs.***

RESPONSE: Big Rivers is in the process of evaluating a potential Demand Response (DR) tariff for both its Member-Owners and large industrial customers. Presently, one (1) of Big Rivers' direct serve loads is an active participant in MISO Demand Response (DR) programs, which has helped Big Rivers better understand how the DR programs work within the MISO market. The energy services department at Big Rivers continues to reach out to large loads to educate and gauge interest in DR and will consider proposing a DR tariff, if there is sufficient interest.

Witness: Terry Wright, Jr.

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

REQUEST NO. 2-5: ***Refer to IRP, Section 5.5, page 87.***

a. ***Provide all assumptions that BREC used when calculating the Demand Response Program Results.***

b. ***Explain what BREC means by "Dynamic Pricing".***

c. ***For the fleet charging (off-peak) program, explain the reasoning for the high TRC score. Include in the response which BREC non-residential customers would participate in this program.***

RESPONSE:

a. The assumptions used in the Demand-Response evaluations are listed below:

i. Cycling of central air conditioning (25%)

1. Base kWh = 3,200 (per unit)
2. Base kW = 2.3 (diversified)
3. kW Reduction = 0.6 (4 groups)
4. Measure Cost = $225 (hardware + install)
5. Member Incentive = $125 + $4/mo bill credit

ii. Cycling of central air conditioning (50%)

1. Base kWh = 3,200 (per unit)
2. Base kW = 2.3 (diversified)
3. kW Reduction = 1.2 (2 groups)

4. Measure Cost = $225 (hardware + install)

5. Member Incentive = $125 + $4/mo bill credit

iii. Central air conditioning control

1. Base kWh = 3,200 (per unit)

2. Base kW = 2.3 (diversified)

3. kW Reduction = 2.3 (1 group)

4. Measure Cost = $225 (hardware + install)

5. Member Incentive = $125 + $4/mo bill credit

iv. Cycling of electric water heating (25%)

1. Base kWh = 3,476 (per unit)

2. Base kW = 0.35 (diversified)

3. kW Reduction = 0.1 (4 groups)

4. Measure Cost = $225 (hardware + install)

5. Member Incentive = $125 + $4/mo. bill credit

v. Cycling of electric water heating (50%)

1. Base kWh = 3,476 (per unit)

2. Base kW = 0.35 (diversified)

3. kW Reduction = 0.2 (2 groups)

4. Measure Cost = $225 (hardware + install)

5. Member Incentive = $125 + $4/mo bill credit

vi. Electric water heating control

1. Base kWh = 3,476 (per unit)

2. Base kW = 0.35 (diversified)

3. kW Reduction = 0.35 (1 group)

4. Measure Cost = $225 (hardware + install)

5. Member Incentive = $125 + $4/mo. bill credit

vii. Peak-Time Rebate (Residential and Non-Residential)

1. Peak Event kW Reduction = 0.39

2. Events per year = 10

3. Hours per year = 40

4. Cost per Member = $5.66

5. Rebate per Member = $40 (total)

viii. Direct Load Control (Residential)

1. Peak Event kW Reduction = 2.0 (diversified)

2. Measure Cost = $225 (hardware + install)

3. Rebate per Member = $4/mo. bill credit

ix. Direct Load Control (Non-Residential – Utility Owned)

1. Peak Event kW Reduction = 250 (diversified)
2. Measure Cost per kW = $400 (hardware + install)
3. Runtime Hours = 100
4. Top 250 MISO Price = $0.24 per kWh
5. Rebate per Member = $0.12 per kWh bill credit

x. Direct Load Control (Non-Residential – Customer Owned)

1. Peak Event kW Reduction = 250 (diversified)
2. Measure Cost per kW = $400 (hardware + install)
3. Runtime Hours = 100
4. Top 250 MISO Price = $0.24 per kWh
5. Rebate per Member = $75,000

xi. Battery Storage (Residential)

1. Base kW = 6
2. System Cost Per MWh = $621
3. Cycles per year = 350
4. Hours per cycle = 4
5. Battery degradation factor = 0.19

6. Coincidence Factor = 0.25 (% chance to hit peak)
7. On-Peak/Off-Peak Savings = [redacted] (From ACES)
8. System Cost = $6,726 (including install)
9. Rebate = $2,354

xii. Battery Storage (Non-Residential)

1. Base kW = 500
2. System Cost Per MWh = $335
3. Cycles per year = 350
4. Hours per cycle = 4
5. Battery degradation factor = 0.23
6. Coincidence Factor = 0.25 (% chance to hit peak)
7. On-Peak/Off-Peak Savings = [redacted] (From ACES)
8. System Cost = $234,500 (including install)
9. Rebate = $82,075

xiii. Residential Level 2 Electric Vehicle Charging

1. Annual Active Charging Hours = 336
2. Annual EV kWh = 3,870

3. % Home Charging = 86%
4. Plug Hours = 7,688
5. Standby Hours = 1,072
6. Baseline Avg. Standby Power = 9.9 W (networked)
7. Efficient Avg. Standby Power = 6.4 W (networked)
8. Efficient Avg. Standby Power = 3.2 W (no vehicle)
9. Peak kW Reduction = 0.28 (diversified)
10. Measure cost = $157 (incremental + setup)
11. Member Rebate = $157

xiv. Commercial Fleet Charging

1. Peak kW Reduction = 38 (electric school bus)
2. System Cost = Assumed meter and charging equipment is already invested. Utility negotiates to control/monitor existing charging equipment.
3. Member Rebate = $50/mo. bill credit

xv. Residential Time-of-Use Rates

1. Base On-Peak MWh = 750,545 (2023)

2. Base Off-Peak MWh = 692,811 (2023)
3. On-Peak MWh Shift = 3%
4. New On-Peak MWh = 731,240
5. New Off-Peak MWh = 712,115
6. On-Peak Price = [redacted] (from ACES)
7. Off-Peak Price = [redacted] (from ACES)
8. Load Factor = 30% (Residential)

xvi. Residential Critical Peak Rates

1. Base CPP MWh = 28,867 (2023 – based on top 100 hours)
2. Base Other MWh = 1,414,489 (2023)
3. CPP MWh Shift = 17%
4. New CPP MWh = 23,947
5. New Other MWh = 1,419,409
6. On-Peak Price = $0.375 (MISO top 100 hours in 2022)
7. Off-Peak Price = [redacted] (from ACES)
8. Load Factor = 30% (Residential)

xvii. Non-Residential Time-of-Use Rates

1. Base On-Peak MWh = 410,012 (2023)

2. Base Off-Peak MWh = 378,472 (2023)

3. On-Peak MWh Shift = 3%

4. New On-Peak MWh = 399,466

5. New Off-Peak MWh = 389,018

6. On-Peak Price = [redacted] (from ACES)

7. Off-Peak Price = [redacted] (from ACES)

8. Load Factor = 65% (Commercial)

xviii. Non-Residential Critical Peak Rates

1. Base CPP MWh = 15,770 (2023 – based on top 100 hours)

2. Base Other MWh = 772,714 (2023)

3. CPP MWh Shift = 17%

4. New CPP MWh = 13,082

5. New Other MWh = 775,402

6. On-Peak Price = $0.375 (MISO top 100 hours in 2022)

7. Off-Peak Price = [redacted] (from ACES)

8. Load Factor = 65% (Commercial)

b. Please refer to Appendix B, Big Rivers 2023 IRP, Demand-Side Management Potential Study, section 5.2.3, page 5-2. Dynamic pricing refers to time-

differentiated pricing of energy and demand. This can include direct market driven prices from markets such as MISO.

c. The high TRC value for the fleet charging program is derived from the assumed structure. Rather than be an alert/control measure, it is assumed that the utility would work through their key accounts or member services group to identify and negotiate up front with the customers so that their charging facilities would always be off-peak in exchange for a regular monthly bill credit. Therefore, there is no large capital investment on the part of the utility. Fast charging for fleet vehicles (especially larger ones like busses, tractors, and larger delivery vehicles) uses a large amount of power in a short period of time. Eliminating this demand combined with the avoided costs results in a large benefit. Big Rivers non-residential members who could benefit from this program include any business with a fleet such as:

i. Delivery vehicles (FedEx, UPS, USPS, etc.)

ii. Agricultural companies and farms with electric tractors

iii. School districts with electric busses

iv. Larger contractor business (plumbing and electrical)

Witness: Joshua Hoyt (Clearspring Energy Advisors, LLC)

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S
SECOND REQUEST FOR INFORMATION

REQUEST NO. 2-6: ***Refer to IRP, Section 5.6, page 88. Provide the capacity costs that BREC is referring to when discussing MISO's forward capacity prices.***

RESPONSE: See the CONFIDENTIAL table below, based on ACES forward capacity curve 11/4/2022:

Year	Capacity ($/kW)
2023	[redacted]
2024	
2025	
2026	
2027	
2028	
2029	
2030	
2031	
2032	
2033	
2034	
2035	
2036	
2037	
2038	
2039	
2040	
2041	
2042	
2043	
2044	
2045	
2046	

CONFIDENTIAL
Filed with Motion for
Confidential Treatment

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S
SECOND REQUEST FOR INFORMATION

Year	Capacity ($/kW)
2047	[redacted]
2048	
2049	
2050	
2051	
2052	
2053	

Witness: Terry Wright, Jr.

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

REQUEST NO. 2-7: ***Refer to IRP, Appendix B, Section 1, page 5.***

a. ***Provide the demand-related and energy-related costs that BREC used.***

b. ***Provide BREC's historical load growth from the past three years.***

RESPONSE:

a. The energy and capacity cost of power is provided in the following CONFIDENTIAL table:

Year	Energy $/kWh	Capacity $/kW
2023	[redacted]	
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		

CONFIDENTIAL
Filed with Motion for Confidential Treatment

Year	Energy $/kWh	Capacity $/kW
2039	[redacted]	
2040		
2041		
2042		
2043		
2044		
2045		
2046		
2047		
2048		
2049		
2050		
2051		
2052		
2053		

b. Big Rivers' 2023 IRP, Appendix A, page 91, displays a detailed view of any Native System historical load growth broken out by energy and consumers at each retail class, and any kW Native system growth. A more condensed summary can be found on Big Rivers' 2023 IRP, Appendix A, page 8.

Witnesses: **Joshua Hoyt (Clearspring Energy Advisors, LLC) (for subpart a.)**

Matthew Sekeres (Clearspring Energy Advisors, LLC) (for subpart b.)

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

REQUEST NO. 2-8: ***Refer to IRP, Appendix B, Section 2, page 1. State how many members participated in BREC's 2022 residential member survey.***

RESPONSE: A total of 1,436 residential retail members responded to the online survey. The response rate was 5.6%.

Witness: Russell L. Pogue

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

REQUEST NO. 2-9: ***Refer to IRP, Appendix B, Section 2, Tables 2.2, page 4. State which non-residential customer (industry type) has the largest load impact.***

RESPONSE: Please refer to the Demand-Side Management Potential Study, Table 2.2, page 2-4 of Appendix B of Big Rivers 2023 IRP. No specific energy usage data from Big Rivers was available by industry type. However, an estimate of the number of accounts was developed using the Census Bureau County Business Patterns. This estimate indicated that the largest sector by number of accounts was Retail Trade (18.4%), followed by Healthcare and Social assistance (13.4%).

Witness: Joshua Hoyt (Clearspring Energy Advisors, LLC)

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

REQUEST NO. 2-10: ***Refer to IRP, Appendix B, Section 3, Tables 3.2 and 3.3, page 2. Confirm that the largest load reduction savings for a residential customer is achieved by reducing HVAC usage. If not, then explain which type of end-use would have the largest load savings.***

RESPONSE: Big Rivers confirms that the largest load reduction savings for a residential customer is typically achieved by reducing HVAC usage. As shown in Tables 3.2 and 3.3, the largest Technical Potential load reduction for the residential customer segment in both energy and demand is expected to come from the HVAC end-use category.

Witness: Joshua Hoyt (Clearspring Energy Advisors, LLC)

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

REQUEST NO. 2-11: ***Refer to IRP, Appendix B, Section 5, page 2. Explain what current DSM/EE programs BREC has that lowers its peak load.***

RESPONSE: Big Rivers does not currently have any DSM programs that lower peak load.

Witness: Terry Wright, Jr.

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

REQUEST NO. 2-12: ***Refer to IRP, Appendix B, Section 5.3.4, page 5. Explain how BREC modeled the Peak-Time Rebate (PTR) program. Include in the response the reasons for the program's high TRC score.***

RESPONSE: The Peak-Time Rebate program is a mass-market behavioral demand response program. The program works by subscribing utility customers who provide a communication protocol (cellphone, e-mail, etc.). When peak conditions are identified (usually a day or so ahead of time), a notification is pushed out that asks customers to reduce energy use during a specific time window. Periodically, the consultant analyzes the peak window on a customer basis and estimates each customer's savings. Customers with a positive savings value receive a credit on their bill based on how many kWs were saved over each of the hours of the event period (a single event might cover multiple hours).

The high TRC score is derived from the cost structure and demand reduction results of the program. The major cost components are the annual cost of the communication portal service, the consultant analytic time, and the rebate itself. It avoids expensive infrastructure investment that needs to be recovered. The costs and amount of kW reduction used in the study per peak event is derived from actual Clearspring Energy Advisors experience.

Witness: Joshua Hoyt (Clearspring Energy Advisors, LLC)

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

REQUEST NO. 2-13: ***Refer to IRP, Appendix B, Section 5.4.1, page 6. Explain if BREC would introduce a time-of-use (TOU) or critical peak pricing (CPP) rate as a DSM program or as an optional rate design tariff option. Include in the response if the TOU or CPP would be more cost-effective and lower BREC's peak load as a DSM program or an optional rate design tariff option.***

RESPONSE: Big Rivers has not determined the appropriate structure of a tariff for TOU or CPP at this time. Big Rivers does not serve retail load and therefore would have to coordinate with the Member-Owner's metering and administrative infrastructure in order to introduce a TOU or CPP rate. Offering TOU through a DSM program or optional rate Tariff design would depend on the overall cost and benefit provided to Big Rivers' membership.

Witness: Terry Wright, Jr.

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

REQUEST NO. 2-14: ***Refer to BREC's responses to Sierra Club's First Request for Information (Sierra Club's First Request), Items 5, 6, 10, and 11.***

a. If BREC has not performed an analysis of the potential costs of compliance considering potential EPA regulations not yet implemented, state how BREC has determined cost inputs for future EPA compliance. If BREC has performed an analysis, provide it.

b. State which environmental compliance variables are included in BREC's IRP modeling.

RESPONSE:

a. Big Rivers has not performed any formal analysis for the cost of compliance with potential EPA regulations that are not yet implemented, and thus it has not determined specific cost inputs for future EPA compliance. However, cost input estimates related to future environmental compliance are reflected in the modeling as described in response to subpart b., below.

b. Carbon dispatch adder sensitivities were priced into the model starting at $5, $15, and $25 dollars per ton in the Low, Mid, and High cases respectively.

Witnesses: **Michael S. Mizell (for subpart a)**

John Christensen (1898 & Co.) (for subpart b)

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

REQUEST NO. 2-15: ***Refer to BREC's responses to Sierra Club's First Request, Item 21. If BREC is in the early stages of evaluating carbon capture and sequestration, state how BREC has determined cost inputs for future potential EPA compliance other than carbon adders.***

a. State whether BREC's IRP model took into consideration potential changes to MISO intermittent resource capacity accreditation.

b. If BREC's IRP model did not include potential changes to MISO intermittent resource capacity accreditation as a variable, state why not.

RESPONSE: Please see Big Rivers' Response to Commission Staff's Request No. 2-14 relating to environmental compliance variables.

a. The IRP modeling included the latest known capacity accreditation methodology available at the time the models were built.

b. Potential changes to MISO intermittent resource capacity accreditation methodologies are uncertain, such that changes may either increase or decrease capacity value at an unknown future date.

Witness: Terry Wright, Jr.

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

REQUEST NO. 2-16: ***Refer to BREC's response to the Attorney General's First Request for Information (Attorney General's First Request), Item 3a. Explain when BREC will know whether it will need to purchase additional energy and capacity to backfill shortfalls in the coming planning year. Include in the response the amount of capacity that may need to be purchased on a seasonal basis to satisfy MISO capacity and reserve requirements each year up through and including 2029.***

RESPONSE: MISO performs updates to values impacting the Seasonal Accredited Capacity Accreditation, including confirmations for MISO's Planning Year 2024/2025 Planning Resource Auction, through March 25, 2024, with the Planning Resource Auction window opening on March 26, 2024. Below is the latest estimate of Big Rivers' seasonal capacity position (megawatts long or (short)) based on current assumptions, including recently posted SAC values. Big Rivers' seasonal capacity position through 2029 does not currently indicate a [redacted]

[redacted]

	Summer	Fall	Winter	Spring
PY23-24	[redacted]			
PY24-25				
PY25-26				
PY26-27				
PY27-28				
PY28-29				
PY29-30				

CONFIDENTIAL
Filed with Motion for Confidential Treatment

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S
SECOND REQUEST FOR INFORMATION

Witness: Terry Wright, Jr.

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

REQUEST NO. 2-17: ***Refer to the Application, Table 7.1.6(a), page 132. Refer also to the Application, Table 4.3(a). Other than the units, explain what the Non-Member Sales and Annual Peak amounts in the tables represent and why they are different. Include in the response why the lesser amounts in Table 7.6.1(a) are included in BREC's modeling.***

RESPONSE: As stated in the IRP Application, page 132, the data in Table 7.1.6(a) "shows Big Rivers' annual Member load forecasts along with **requirements** to serve non-Member load" (*emphasis added*). As stated in the IRP Application, page 67, "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." Table 4.3(a) displays the annual peak NCP forecast. The Non-Member Sales NCP forecast, also shown in Table 4.3(a), includes sales to Nebraska customers.

The Non-Member Peak load shown in Table 7.1.6(a) and included in the Base Case, are lower as a result of the capacity already purchased to serve the Nebraska customers in Southwest Power Pool (SPP), which is not an additional requirement and could be considered a "net" Non-Member capacity position.

Witness: Terry Wright, Jr.

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

REQUEST NO. 2-18: ***Refer to BREC's response to Commission Staff's First Request for Information (Staff's First Request), Item 2.***

a. Confirm that BREC's contracted Non-Member customers in the Southwest Power Pool (SPP) are not reflected in its MISO planning reserve margin requirement (PRMR) and that its other Non-Member customers (KYMEA and OMU) residing in Kentucky are reflected in its MISO PRMR.

b. If BREC neither generates nor transmits energy to its Non-Member contract customers in the SPP, explain operationally how these customers are served.

c. Explain why Non-Member load should not be reflected in the total system peak.

d. Refer also to the Application, Table 7.1.6(a), page 132. Confirm that the Non-Member Annual Energy (GWh) and Annual Peak (MW) amounts represent the Non-Members residing in Kentucky and not the Non-Members residing in the SPP. If not, explain how and what portion, if any, of Non-Member energy and capacity is included in BREC's modeling.

RESPONSE:

a. Confirmed.

b. Big Rivers serves Nebraska customers' energy needs pursuant to the SPP Open Access Transmission Tariff. Big Rivers acquires energy through bilateral purchases and submission of hourly bids in SPP's Day Ahead and Real Time Balancing market. Big Rivers purchases capacity bilaterally to meet SPP resource adequacy requirements, which is submitted via SPP's Engineering Data Submission Tool.

c. Non-Member Sales are included in Table 4.3(a) as a part of total System NCP. In Table 7.1.6(a), Member and Non-Member Load is included in the Base Case, with the exception of Nebraska customers as explained in Big Rivers' Response to Commission Staff's Request No. 1-17.

d. Confirmed. See Big Rivers' Response to Commission Staff's Request No. 2-17.

Witness: Terry Wright, Jr.

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

REQUEST NO. 2-19: ***Refer to BREC's response to Staff's First Request, Item 3. Explain whether BREC's own energy and capacity usage is captured in the AUX category. If not, explain [what] the AUX power represents and how BREC's own energy and capacity use are included in the modeling.***

RESPONSE: Big Rivers' own energy and capacity usage is captured in "AUX" or auxiliary power as listed in Table 2.2.8(a) (and Table 2.2.8(b)) of the IRP. This category represents auxiliary power required by certain Big Rivers generators which have retired.

Witness: Terry Wright, Jr.

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

REQUEST NO. 2-20: ***Refer to BREC's response to Staff's First Request, Item 8.***

a. Explain why OMU is modeled as inclusive of SEPA hydropower supply when that amount reduces BREC's obligation for both energy and capacity.

b. Explain why OMU net of SEPA hydropower supply would not be included in the model in the same manner as KYMEA.

RESPONSE:

a. The Table 7.1.6(a) base case load has been analyzed using an hourly load profile to allow EnCompass to optimize all resource usage, including the OMU SEPA resource. It is important to note that both Big Rivers and OMU have PPAs with SEPA and both receive their own separate allocation of energy and capacity. The amount that is reducing Big Rivers' obligation is Big Rivers' SEPA entitlement.

b. Pursuant to the Agreement for the Purchase and Sale of Full-Requirements Capacity and Energy between Big Rivers and OMU, Big Rivers utilizes its SEPA entitlement. Contractual requirements to serve KYMEA, which is effectively a call option, are different.

Witness: Terry Wright, Jr.

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

REQUEST NO. 2-21: ***Refer to BREC's response to Staff's First Request, Item 9.***

a. Explain what the coincidence factor for BREC CP to MISO CP represents and why it is necessary for modeling purposes.

b. For the Base Case, explain why transmission losses are excluded from Base Case Member peak in the Encompass model. If included, explain how.

c. Explain whether distribution losses are included in the modeling. If included, explain how.

d. Refer also to IRP, Table 7.1.6(a). In the table, explain what the forecast of Non-member (OMU and KYMEA) energy and peak actually represent. Include in the response whether actual historical energy (GWh) and capacity (MW) coincident with Member energy and Member system peak were included in the Encompass model.

RESPONSE:

a. BREC's Member-Owner load is made up of several different customer classes across the three different Member-Owners. Each Member-Owner's load peaks individually at different times, meaning that the overall peak of Big Rivers' total Member-Owner load is not the sum of the individual peaks; rather, it is the coincident peak ("BREC CP"), which typically occurs when all three Member-Owners are near (but not at) their individual peaks. Similarly, the MISO system peak occurs when many of their member utilities are near peak, resulting in the highest load that MISO will conjunctively measure at any one point in time. The BREC to MISO coincidence factor represents the approximate percentage of Big Rivers' coincident peak,

measured at the time of the MISO system peak. The resulting MISO CP value is used in planning to ensure that Big Rivers has enough capacity to cover its obligations to the MISO footprint during a peak event.

b. The MISO coincidence adjusted demand forecast is scaled up by 2.34% to account for transmission losses and is applied monthly in the demand forecast.

c. Distribution losses are included in the forecast. Distribution energy losses are included and broken out separately in the Rural "total" section shown in Big Rivers' 2023 IRP at Appendix A, page 39. The Rural system peak totals shown in Big Rivers' 2023 IRP at Appendix A, page 49, also include distribution losses in the values.

d. Non-Member energy and peak values reflect the volumes that Big Rivers expects to be providing to OMU and KYMEA based on contractual terms. Actual historical load and capacity were used to create the OMU forecast. KYMEA peak usage and energy was forecasted based on expected LMPs.

Witnesses: **John Christensen (1898 & Co.) (for subpart a)**

Matthew Sekeres (Clearsprings Energy Advisors, LLC) (for subpart c)

Terry Wright, Jr. (for subparts b and d)

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

REQUEST NO. 2-22: ***Refer to BREC's response to Staff's First Request, Item 11. Provide annual DSM program total costs and generation savings since BREC's DSM program was first implemented.***

RESPONSE: Big Rivers' DSM-14 Low-Income Weatherization Support Program – Pilot was introduced in 2020. One project was completed in 2020 at a cost of $2,548, and one project was completed in 2021 at a cost of $3,000. No projects were completed in 2022 or 2023 due to availability of Weatherization Ready funds through the Department of Energy. Based on discussions with the Kentucky Housing Corp, Big Rivers anticipates that the program may be more impactful in 2025, based on anticipated Weatherization Ready funding levels.

Demand reduction as a result of these two projects is de minimis and has not been calculated.

Witness: Russell L. Pogue

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

REQUEST NO. 2-23: ***Refer to BREC's response to Staff's First Request, Item 13.***

a. ***Explain how the Encompass model was configured to simulate a typical two day week, one on peak day and one off peak day.***

b. ***If not answered above, explain whether for modeling purposes, one weekly on peak day and one weekly off-peak day means that there were 52 observations for peak and off-peak days per year.***

c. ***Explain whether for each typical on peak and off peak day, there are 24 hourly observations used in the model.***

d. ***Explain whether the results of this method were or have been compared to running the Encompass model with all of the hourly observations in the review period in order to test the accuracy and assertion that the results are mainly unaffected by the reduction in observations leading to reduced simulation time. If so, provide the results of that comparison.***

RESPONSE:

a. In typical two-day week simulations, two days are used to represent each month over the study period. Results are reported as the first day of the "month" representing the on-peak day, and the second day of the "month" representing the off-peak day. Average values are calculated across each day for the month, except for certain inputs such as Demand (MW) for Load Groups, in which a ranked peak algorithm is used. This preserves the peak load, energy, and hour of peak, and in most cases, the minimum load. The Net Dispatch Limit (%) typically used for renewable and energy efficiency shapes uses a similar ranked average algorithm which will

preserve the average availability and attempt to preserve the maximum and minimum values. All calculations are done by EnCompass' built-in algorithms.

b. During typical on-peak and typical off-peak analysis, two days are simulated for each month. This would equate to 24 "days" per year.

c. Each "day" in the simulation is 24 hours long.

d. Simulating hourly observations for an entire year (8760 hours per year) in expansion planning is impractical due to memory and system requirements. 1898 & Co. has tried simulating entire calendar years on an hourly basis during Expansion Planning simulations in EnCompass for other clients and has been unsuccessful even when using computers with 64 processor cores and hundreds of gigabytes of memory. It has been the professional observation of 1898 & Co. that EnCompass' typical 2-day expansion planning simulations are sufficient to develop a portfolio for further study in the Base, Alternative, and Advanced Carbon Reduction Portfolios of the Production Cost Modeling.

Witness: John Christensen (1898 & Co.)

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

REQUEST NO. 2-24: ***Refer to BREC's response to Staff's First Request, Item 14.***

a. Because BREC didn't make any forecasted fixed or variable O&M costs available to the consultants for the Green units resulting in the Green units retirement in 2029, did not allow the Encompass model the option to retire either the Reid or Wilson units, or allow the model to decide whether and did not rerun the base case scenarios once all data for the PACE project was known and available, explain why the Commission should have any confidence that BREC's preferred plan is the most reasonable least cost plan.

b. Provide the annual forecast O&M and capital expenditures for the two Green units, separating the costs out by unit where appropriate.

c. Provide the results from at least one additional run of the Encompass model, all else being equal, allowing the model the option to retire and replace one or both Green units, the Reid unit and the Wilson unit.

RESPONSE:

a. Big Rivers provided forecasted fixed O&M costs for the Green Units, but there are no non-fuel variable O&M costs for the Green units, as the units were recently converted to natural gas. There were two retirement scenarios for Green, one in 2029 (aligning with the amortization of the Green Conversion in 2029, as discussed in Case No. 2021-00079) and one in 2043 (based on the Member-Owners' contract terms), both of which had fixed O&M costs associated with them.[1] If Big Rivers runs the Green units past 2029, significant capital and O&M costs would

[1] *See Electronic Application of Big Rivers Electric Corporation for a Certificate of Public Convenience and Necessity Authorizing the Conversion of the Green Station Units and an Order Approving the Establishment of a Regulatory Asset*, Case No. 2021-00079 (Mar. 1, 2021).

have to be expended to ensure reliability and resilience to the Member-Owners, which costs are reflected in the modeling of the 2043 retirement scenario.

The Request further suggests that all the data for the PACE project are known and available; however, all of the data is not available—the PACE project is a relatively new opportunity and the application was only recently submitted to RUS in January of 2024. Big Rivers will file the appropriate application with the Commission once there is sufficient data available to support it.

Finally, Reid has very low fixed O&M costs, and it would have been unlikely that the model would have shown Reid as retired. Wilson is a reliable base-load resource with a strong operational history, and Big Rivers has no intent to retire Wilson before the end of the Member-Owners contracts' term. Please also see Big Rivers' Response to subpart c below, as well as its Response to Commission Staff's Request No. 2-24.

b. Please see the attached CONFIDENTIAL workbook (filed subject to a motion for confidential treatment) for the Green Units, broken out by category.

c. It is infeasible to model a potential replacement for the Reid unit and/or the Wilson unit at this time. Big Rivers' efforts to develop the 2023 IRP involved many months of examination and discussion by and among various departments and disciplines, both internal and external to Big Rivers. Not only would the requested additional modeling require the unrealistic assumption that Big Rivers would or could replace such a significant portion of its power supply,

it would require a complete re-tooling of the entire EnCompass model, as well as a resetting of multiple, fundamental, baseline assumptions including (but not limited to) geographical considerations associated with potential power supply locations, transmission impacts, potential retirement costs, and other necessary capital expenditures, operational changes, generation resource reliability and diversity considerations, market risk, and potential stranded assets. There are significant data and computational challenges associated with altering such fundamental assumptions, and any efforts to do so at this stage would undoubtedly suffer from the extensive data-gathering and related work that informs the year-long process of preparing an integrated resource plan.

As the applicable regulation notes, Big Rivers is entitled to make certain key assumptions in the course of performing its analysis, and those assumptions are addressed, in part, at Section 10 ("Action Plan") of the IRP:

> *For Big Rivers, the 2023 IRP highlights a path based on an "all of the above" approach to sustainability and reliability, working to incorporate coal, natural gas, hydropower, and solar energy to increase sustainability while maintaining efficient and reliable baseload electricity for all Member-Owners.*
>
> *Big Rivers' mission to safely deliver low-cost reliable wholesale power to its Member-Owners is an ongoing effort, necessitating robust analysis of existing and potential load and resources. Big Rivers will leverage its access to wholesale power markets to maximize Member value while ensuring sufficient steel in the ground to minimize risk and promote reliability.*

> *This triennial IRP filing incorporates the best information available at the time of analysis, and as circumstances change, plans will be adjusted. This plan is not a commitment for certain actions now or at any future date.*[2]

Please also see Big Rivers' response to Commission Staff's Request No. 2-30.

Witnesses: **John Christensen (1898 & Co.) (for subpart b)**

Nathanial A. Berry (for subparts a and c)

[2] Big Rivers' 2023 Integrated Resource Plan at p. 178; *see also* 807 KAR 5:058 Sec. 8 and KRS 278.264.

PSC 2-24 ATTACHMENT

This attachment, in its entirety, has been submitted under seal with an accompanying request for confidential treatment.

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

REQUEST NO. 2-25: ***Refer to BREC's response to Staff's First Request, Item 18. Confirm that the IRP represents BREC's current long-range plan going forward and that it represents its intentions as of the filing date.***

RESPONSE: Big Rivers 2023 IRP represented its intentions as of the filing date using the information gathered and modeled during the yearlong IRP process. The IRP filing is best viewed as the continuation of a process, representing a snapshot in time amidst ongoing analyses.

Big Rivers' long-range plan going forward remains the same as stated in the 2023 IRP: "a path based on an 'all of the above' approach to sustainability and reliability, working to incorporate coal, natural gas, hydropower, and solar energy to increase sustainability, while maintaining efficient and reliable baseload electricity for all Member-Owners." Big Rivers aims to seek and act on the best available information while remaining focused on compliance, responsibility, reliability, and cost-effectiveness**.** As stated in Big Rivers' response to Commission Staff's Request No. 2-40 related to the proposed PACE project, when information and resources become available for Big Rivers to adjust its generation resources in the best interest of its Member-Owners, Big Rivers will take steps to obtain any required Commission approval it needs to implement those adjustments.

Witness: Nathanial A. Berry

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

REQUEST NO. 2-26: ***Refer to BREC's response to Staff's First Request, Item 20. Refer also to the Application, page 107. Explain whether BREC's respective generator pricing nodes are different from the load node, where all purchases are made and priced. If there are differences, explain the differences and how that is modeled in the Encompass model.***

RESPONSE: Please refer to Big Rivers' Response to Kentuckians for the Commonwealth/Kentucky Resource Council Request No. 2-47 for additional details. The EnCompass IRP analysis is representative of a zonal market interaction as opposed to a full nodal model – this is typical in IRP analysis. Each BREC generator area or "node" was fed a pricing time series which was generated from MISO market simulations using Horizons Energy National Database. Similarly, the Big Rivers' load area "node" in the model was configured to allow for all load energy to be purchased from the MISO market based on an hourly price time series. Generally, the pricing for generator nodes was less than the pricing for the load node in any given hour. This is generally consistent with the way the MISO market functions day to day.

Witness: John Christensen (1898 & Co.)

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

REQUEST NO. 2-27: ***Refer to BREC's response to Staff's First Request, Item 21. If BREC intends to attempt to renew the Non-Member contracts, explain why the extension was not modeled in the IRP.***

RESPONSE: As indicated in Big Rivers' Response to Commission Staff's Request No. 1-21, Big Rivers is pursuing renewal of the Non-member contracts, with the exception of the Nebraska contracts. Extensions were not modeled in the IRP as the probability of extension was unknown at time of IRP modeling, as were the terms upon which any potential renewal would be made.

Witness: Terry Wright, Jr.

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

REQUEST NO. 2-28: ***Refer to BREC's response to Staff's First Request, Item 22.***

a. ***State whether BREC's IRP model included potential changes to MISO intermittent resource capacity accreditation as a variable.***

b. ***If BREC's IRP model did not include potential changes to MISO intermittent resource capacity accreditation as a variable, state why not.***

RESPONSE:

a. Please see Big Rivers' Response to Commission Staff's Request No. 2-15.

b. Please see Big Rivers' Response to Commission Staff's Request No. 2-15.

Witness: Terry Wright, Jr.

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

REQUEST NO. 2-29: ***Refer to BREC's response to Staff's First Request, Item 25. Confirm that depending on the month and loading level, the Encompass model would select the appropriate value from one of the various capacity blocks in the table.***

RESPONSE: Table 7.1.4 (c) represents the operational parameters of the Big Rivers combined cycle, as constrained in the EnCompass model. Depending upon the unit's month and current operating point, the heat rate associated with those values in the table would be used to determine the dispatch costs.

Witness: John Christensen (1898 & Co.)

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

REQUEST NO. 2-30: ***Refer to BREC's response to Staff's First Request, Item 26. BREC states that "Providing the model with the opportunity to retire a unit(s) in any year creates significant data and computational challenges with limited value in this case."***

a. Provide support that allowing the model to retire units in any year provides limited value in this case. Include in the response a discussion of when allowing the model to do so would provide significant value.

b. Explain whether the Encompass model is able to model BREC's units cost effectively retiring in any year.

c. Explain whether BREC made the decision to restrict the model's capability with respect to allowing the model to retire units in any year. If so, explain the rationale for the decision.

RESPONSE:

a. See Big Rivers' response to Commission Staff's Request No. 2-24. It would be more valuable to study retirement options at discrete points in time such as after changes in environmental regulations or major maintenance milestones rather than on a yearly basis.

b. See Big Rivers' response to Commission Staff's Request No. 2-24. Typically utilities do not model allowing unit retirement every year, but only when there is a significant shift in anticipated cost profile, such as amidst large outage requirements or pending regulatory changes.

c. See Big Rivers' response to Commission Staff's Request No. 2-24.

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S
SECOND REQUEST FOR INFORMATION

Witnesses: Nathanial A. Berry (for subparts a and c)

John Christensen (1898 & Co.) (for subpart b)

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

REQUEST NO. 2-31: ***Refer to BREC's response to Staff's First Request, Item 28.***

a. Explain the purpose of the Variable O&M amount and why it is added to the Wilson variable O&M cost.

b. Explain why the adder is excluded from the Green and Reid units.

c. Explain whether MISO or BREC decided to include the adder.

d. Explain the operational causes of the $38.10 variable O&M for Unbridled solar.

e. Explain whether the annual amounts in the table were broken out by seasonal or smaller time increments. If so, explain how variable O&M was modeled.

RESPONSE:

a. The values represented in Table 7.1.4(e) on page 118 of the IRP show the non-fuel variable O&M costs. They are not adders; they are actual costs incurred in MW production. As an example, limestone is a component of a non-fuel variable O&M cost.

b. Green 1, Green 2, and Reid CT are natural gas fired. These units do not have any non-fuel variable O&M costs.

c. Inclusion of non-fuel variable O&M when calculating production costs was decided by Big Rivers, consistent with common industry practice that began prior to the establishment of MISO.

d. The Unbridled solar unit is modeled as a PPA agreement with a fixed rate of $38.10/MWh. There are no additional costs in the model for Unbridled beyond its PPA energy price.

e. The variable O&M amounts referred to in Big Rivers' Response to Commission Staff's Request No. 1-28 were modeled annually between January 1st and December 31st of each year. Modeling was not performed on a seasonal or smaller time increment basis.

Witnesses: **Nathanial A. Berry (subparts a – c)**

John Christensen (1898 & Co.) (subparts d and e)

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

REQUEST NO. 2-32: ***Refer to BREC's response to Staff's First Request, Item 29.***

a. ***Explain whether there is any utility scale wind facilities in BREC's MISO Load Zone 6.***

b. ***Explain when BREC sent out its All-Source Request For Proposal (RFP), when the responses were received, the analysis supporting the statement that the wind and solar purchase power agreements were not economical compared to the NGCC.***

RESPONSE:

a. According to MISO's Interconnection Queue[1] there are several approved wind projects in Indiana, which is in MISO Local Resource Zone 6, but none are in the Big Rivers Local Balancing area.

b. The All-Source RFP was issued April 1, 2022, with proposals due by June 1, 2022.[2] The NGCC bid in the All-Source Request for Proposals provided dispatchable energy and reliable capacity at a market-competitive heat rate. The solar, storage, and hybrid resources could not provide the same level of flexibility that Big Rivers needs to protect its members from price exposure in the market at or near the same pricing point.

[1] https://www.misoenergy.org/planning/resource-utilization/GI_Queue/gi-interactive-queue/

[2] See Big Rivers' Response to Kentuckians for the Commonwealth/Kentucky Resource Council's Request No. 1-9 for a copy of the RFP.

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S
SECOND REQUEST FOR INFORMATION

Witnesses: **Terry Wright, Jr. (for subpart a)**

Nathanial A. Berry (for subpart b)

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

REQUEST NO. 2-33: ***Refer to BREC's response to Staff's First Request, Item 30c and 35.***

a. Explain whether the response means that BREC modeled the 100 MW solar and the 50 MW 4-hour battery storage separately as if they were not going to function as a combined/complementary unit.

b. If so, refer to BREC's response to Staff's First Request, Item 29c where wind and solar resources were not economical compared to the NGCC unit. Explain the apparent differences in outcomes.

c. Explain how the RFP responses compare to the generic economic / operational assumptions used in the Encompass model.

RESPONSE:

a. The 100 MW Solar and 50 MW 4-hour battery (PACE Project) were modeled as separate components of a single project. Because they are AC-coupled components, they will be able to function independently of each other but may realize synergies depending on real-world market conditions.

b. The PACE project enjoys significant cost and financing advantages over other potential opportunities involving intermittent generation. On November 30, 2023, Big Rivers was invited by the Rural Utilities Service to submit a full application for the PACE program. The invitation included an opportunity to obtain a loan in the amount of $100,000,000, of which up to 20 percent is eligible for forgiveness. Big Rivers also anticipates receiving other Investment Tax

Credits associated with the solar project. The completed PACE application was submitted in January 2024.

c. During the capacity expansion analysis, the generic alternatives were modeled with the assumption that Big Rivers would own and operate the selected facility. The RFP responses with respect to intermittent resources, conversely, reflected PPA structures. Please refer to IRP Table 7.1.4(a) and Table 7.1.4(g) for further information on the modeled resource alternatives.

Witness: **John Christensen (1898 & Co.) (for subparts a and c)**

Talina R. Mathews (for subpart b)

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

REQUEST NO. 2-34: ***Refer to BREC's response to Staff's First Request, Item 31. Regardless of whether the values for the MISO cost of new entry are in nominal or real dollars, explain why it is reasonable to make the simplifying assumption that the price to remain constant over the 25-year review period.***

RESPONSE: The MISO cost of new entry (CONE) input was sourced from the MISO October 4th, 2021, CONE filing report for LRZ 6. Aside from the annual MISO capacity auction, a comparable analysis/metric for forecasting capacity pricing does not exist. Please also note that the CONE-based price for capacity did not remain constant over the 25-year study; the values were escalated to reflect year-over-year increases in pricing tied to inflation estimates.

Witness: John Christensen (1898 & Co.)

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

REQUEST NO. 2-35: ***Refer to BREC's response to Staff's First Request, Item 32.***

a. Explain whether the Encompass model is capable of dispatching units as must run, putting the units in reserve shutdown or modeling actual experienced unit behavior. If so, explain why the model was programmed to have the units bid into the MISO market as "economic" and not allowed these additional options.

b. Explain whether the Wilson, Reid, and Green units are ever bid into the MISO market as something other than "economic" or go into reserve shutdown status.

c. If the units are bid into the MISO market as "must run," explain whether BREC is paid the hourly cost of the unit or the LMP, whichever is higher. If not, explain what amount is paid to BREC.

d. Explain how maintenance outages (planned or otherwise) was treated in the Encompass model.

RESPONSE:

a. The EnCompass model is an economic dispatch modeling tool and is used to determine the economic value of existing resources and fleet alternatives among several other co-optimization variables. The model does contain the functionality to consider resources as "must run." However, to determine a least-cost portfolio, it is prudent to dispatch these units against simulated market pricing, unless the unit cannot start/stop as needed (as, for example, in the case of a nuclear steam unit). The EnCompass model does not attempt to model different unit statuses such as reserved shutdown or others which are tied to outage reporting under NERC guidelines rather than market operations.

b. Wilson, Reid, and Green units have been offered to the MISO market as "must run" to accommodate testing, reliability, or economic conditions. There is no "reserve shutdown" offer status in the MISO market.

c. When units are offered as "must run," MISO pays the generators the hourly LMP for the cleared volume.

d. For unplanned or forced outages, EnCompass uses random number draws to determine which individual units will experience an outage on a given simulation day due to mechanical failure, which resources will experience partial outage, and which units have no operational limitations. Forced outages are modeled in EnCompass slightly differently depending on the type of simulation. In expansion planning runs, the model was set to "use capacity durations" which takes the maximum capacity for that day on each unit and derates it based on the unit's forced outage rate. For hourly production cost runs, this input is set to "New outages with convergence," which uses the forced outage rate to determine the number of full forced outage days per year and will randomly select the dates in each year using a random draw. Planned outages are entered into the model as discrete dates by unit.

Witnesses: **John Christensen (1898 & Co.) (for subparts a and d)**

Terry Wright, Jr. (for subparts c and b)

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S
SECOND REQUEST FOR INFORMATION

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

REQUEST NO. 2-36: ***Refer to BREC's response to Staff's First Request, Item 32. Refer also to Case No. 2023-00312, Rebuttal Testimony of Terry Wright, Jr., page 3, lines 12-22 and page 4, lines 1-4. Compare, contrast and explain the extent to which the Encompass model mimicked or incorporated the method by which BREC's capacity resources are accredited by MISO.***

RESPONSE: Capacity modeling within EnCompass was based upon available data from MISO. For existing units, SAC values were taken directly from MISO with no adjustments. For new units, we incorporated components of the SAC Calculation, but could not incorporate all the components. For example, we took into account the maximum capacity, the ISAC/ICAP ratio, and an ELCC factor, but could not take into account performance during Tier 2 hours as we would have no historical basis for this calculation.

Please also see Big Rivers' Response to Commission Staff's Request No. 2-15.

Witnesses: **Terry Wright, Jr.**

John Christensen (1898 & Co.)

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

REQUEST NO. 2-37: ***Refer to BREC's response to Staff's First Request, Item 35.***

a. ***Explain whether the annual capacity factors for the generic wind and solar resources are different if measured seasonally in MISO's new seasonal capacity requirement.***

b. ***Potential resource performance can change according to the season. Explain whether BREC modeled potential resource attributes, including capacity factors, according to the new MISO seasonal capacity requirement or simply included annual figures.***

RESPONSE:

a. The annual capacity factor and MISO's seasonal capacity requirement are two different things. The annual capacity factors measure the expected energy production over a year against the maximum potential energy production over a year. MISO's seasonal capacity requirement looks at the likelihood that the generation will be available when it is called upon based on a Loss of Load Expectation of 1 day in 10 years. The output of an annual capacity factor is an annual percentage while the output of MISO's new seasonal accreditation is a MW value for each season for each unit.

b. The capacity factors listed in Big Rivers' Response to Commission Staff's Request No. 1-35 were calculated and presented on an annual basis. The profiles modeled in EnCompass were input with hourly granularity, which would capture seasonal behavior. Wind and Solar resources also had different firm capacity values in each MISO capacity season. The shifts in firm

capacity values were driven by ELCC values, which changed seasonally. Again, all such seasonal changes were captured within the EnCompass model's more granular hourly profiles.

Witnesses: **Terry Wright Jr. (for subpart a)**

John Christensen (1898 & Co.) (for subpart b)

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

REQUEST NO. 2-38: ***Refer to BREC's response to Staff's First Request, Item 38(b).***

a. Explain why a $1 million annual DSM budget was used. State why actual estimated costs were not used for programs with TRC scores indicating cost-effectiveness.

b. Explain what BREC means by "it was assumed that all the measures from the achievable potential would be available."

c. State whether the Encompass model is capable of integrating individual DSM programs as variables. If so, explain why this function was not utilized.

RESPONSE:

a. A $1 million annual DSM budget was used because of the need for a discrete investment budget. The $1 million figure used in the 2023 IRP aligns with Big Rivers' previous IRP cycles, therefore creating consistency with past approved IRP work. The Demand-Side Management Potential study is an estimate of the varying levels of energy efficiency that might be available in the utility service area. It is not a DSM Design study, which creates specific programs that would be ready for real-world deployment.

b. Individual measures that successfully passed the Achievable Potential analysis were all considered available to provide potential energy and demand savings in the Program Potential phase. As discussed in subpart a., the DSM study is a Potential study and not a Design

study. Without specific programs, the various end-use categories were assigned costs from the passing measures and Potential savings were scaled up to meet the $1 million annual budget.

c. EnCompass is capable of analyzing multiple energy efficiency and demand response programs. As discussed in subpart b of this Response, the Program potential modeled as part of this IRP was a conglomerate of energy savings by end-use, based on measures passing the Achievable potential analysis. The DSM study goal was estimating DSM potential, it is not a design study.

Witnesses: **Joshua Hoyt (Clearspring Energy Advisors, LLC) (for subparts a, b and c)**

John Christensen (1898 & Co.) (for subpart part c)

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

REQUEST NO. 2-39: ***Refer to BREC's response to Staff's First Request, Item 39 and 40.***

a. Explain when BREC intends to submit the PACE project into the MISO interconnection queue or whether BREC has conducted any transmission studies that indicate that the PACE project will alleviate any transmission contingencies or constraints. If so, provide either the study results or an update on the status of these studies.

RESPONSE: MISO is temporarily preventing new submittals into the Generator Interconnection Online Portal. MISO anticipates reopening the queue window in late Q1 2024 with an application deadline in late Q2 2024. Consequently, the PACE project will be submitted to MISO no earlier than Q2 2024. No transmission contingencies or constraints have been identified that will be alleviated by the PACE project.

Witness: Christopher Bradley

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

REQUEST NO. 2-40: ***Refer to BREC's response to Staff's First Request, Item 40.***

a. Provide a status update to BREC's loan application.

b. Explain whether BREC has taken any of the preliminary actions toward the siting and permitting for the PACE project and, if so, provide a status update of those actions.

c. Explain when BREC intends to file an application for a certificate of public convenience and necessity (CPCN) and for new financing obligations.

RESPONSE:

a. Big Rivers submitted its PACE application on January 29, 2024, seeking $100 million from RUS.

b. Big Rivers has identified potential site options for the McCracken Solar project. It has not pursued siting or permitting efforts at this time, pending further clarity from RUS on Big Rivers' application for financing.

c. Big Rivers will file an application seeking a certificate of public convenience and necessity (CPCN) prior to beginning construction and consistent with the requirements of applicable law, including KRS 278.020. This will occur after Big Rivers receives notification from RUS of a conditional approval on the loan application. Big Rivers does not expect to seek approval in connection with new financing obligations in connection with this project, as the financing would be solely from RUS.

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S
SECOND REQUEST FOR INFORMATION

Witness: Talina R. Mathews

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

REQUEST NO. 2-41: ***Refer to BREC's response to Staff's First Request, Item 41b. Refer also to Item 14 and Item 53. If the fixed and variable O&M costs for the Green units were not available to the Encompass model, then explain how the phrase "but because the expense of keeping the facility operational was greater than the economic benefits of replacement" is valid. Wouldn't the expense of keeping the facility operational depend on the ongoing costs that were not available? If not, please explain why not.***

RESPONSE: Please refer to Big Rivers' Responses to Commission Staff's Requests Nos. 2-24(b) and 2-31(b). Fixed O&M costs associated with Green Station running until 2029 and 2043 (respectively) were evaluated in the EnCompass model and used in part to compare the unit's economic viability with other options. The projected fixed costs associated with Green 1 and Green 2 remaining operational until 2043 was a significant factor in the models' decision to retire them and pursue a new combined cycle power plant with an efficient heat rate. Following expansion planning, EnCompass was used to model chronological economic dispatch in all hours of the year, which considers the unit heat rate, variable O&M, and fuel costs, including natural gas delivery adders. The economic value of the new combined cycle was greater than the value of keeping the Green 1 and Green 2 units.

Witness: John Christensen (1898 & Co.)

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

REQUEST NO. 2-42: ***Refer to BREC's response to Staff's First Request, Item 42.***

a. ***Under the New ERA Program, explain the circumstances under which combustion turbines would be required to install carbon capture and sequestration (CCS) technology.***

b. ***Confirm that BREC's current intention is to place CCS technology on the Wilson unit. Include in the response whether the Wilson and NGCC units were modeled as equipped with CCS technology beginning in 2032 in the BREC's preferred plan. If not, explain why not and rerun the modeling of the preferred plan to include CCS technology as the only change to the assumptions.***

c. ***Explain the energy penalties for the Wilson and NGCC units from installing CCS technology and whether that impacts the available MISO accredited capacity of the units.***

d. ***Explain how the forecasted MISO energy LMPs were adjusted to account for the installation of CCS technology across the MISO load zones.***

RESPONSE:

a. Under the New ERA program, combustions turbines are not required to install CCS technology. The program prioritizes greenhouse gas reductions rather than requiring the use of specific technologies. The new NGCC unit is modeled with CCS technology in the most stringent carbon scenario.

b. Big Rivers' current intention is to consider pursuing CCS technology on the Wilson unit if invited to apply for the New ERA funding and loan program. If Big Rivers is not selected

to apply, the economics of CCS technology will be evaluated. Wilson and NGCC units were modeled as equipped with CCS technology in the most stringent carbon scenario.

c. There is a capacity (and energy) penalty when implementing CCS technology on any power plant, including the Wilson and NGCC units. The reduction in accreditable capacity is due to the additional station service load required to operate the carbon capture and sequestration equipment. The additional load reduces the net output of the unit(s), which in turn results in lower generation verification test results.

d. The modeling included carbon dispatch adder sensitivities (low, mid, and high) in which the market LMPs were impacted by a carbon dispatch adder applied across MISO. These sensitivities are proxies for the market impacts of potential future CO_2 regulation scenarios.

Witnesses: **Talina R. Mathews (for subparts a and b)**

Nathanial A. Berry (for subpart c)

John Christensen (1898 & Co.) (for subpart d)

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

REQUEST NO. 2-43: ***Refer to BREC's response to Staff's First Request, Item 43.***

a. Explain the New ERA Program criteria for whether a NGCC unit would be required to install CCS technology.

b. If the NGCC unit will be required to install CCS technology by 2032, explain why the reduction in greenhouse gasses is a relevant factor in whether or not to apply for financing and grant incentives.

RESPONSE:

a. See Big Rivers' Response to Commission Staff's Request No. 2-42(a).

b. The new NGCC unit is modeled with CCS technology in the Aggressive Carbon Reduction scenario because, in that case, Big Rivers anticipates any new fossil generator may be required to have such technology available in order to gain regulatory approvals for its construction. The New ERA program was established to help with the transition to clean, affordable and reliable energy. The program prioritizes greenhouse gas reductions, and Big Rivers' proposed project submitted as a LOI for New ERA reflects this priority. *See* CONFIDENTIAL attachment to Kentuckians for the Commonwealth and Kentucky Resource Council's Request No. 1-13.

Witness: Talina R. Mathews

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

REQUEST NO. 2-44: ***Refer to BREC's response to Staff's First Request, Item 44. Explain whether BREC has investigated any of the practical aspects of installing CCS at its generation sites, including how and where the CO2 will be stored prior to transportation to long term storage, how the gas will be transported, and what costs, including liability, will be borne by BREC.***

RESPONSE: The practical aspects of installing CCS will be included in future studies conducted by Big Rivers.

Witness: Talina R. Mathews

IN THE MATTER OF:
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

REQUEST NO. 2-45: ***Refer to BREC's response to Staff's First Request, Item 50. Explain whether BREC has actually purchased capacity either bilaterally or in the Planning Reserve Auction and, if so, the amount purchased and the period covered by the purchase.***

RESPONSE: Big Rivers purchases all of the capacity to meet its MISO Planning Reserve requirements in the Planning Resource Auction. Big Rivers may also purchase capacity within a planning year to address anticipated capacity shortfalls either bilaterally or through the Planning Resource Auction, depending on what Big Rivers views as the most economic and risk-prudent approach. Big Rivers has acquired seventy-five (75) zonal resource credits (ZRCs) for the Planning Year 2024/25 for the period 6/1/24-5/31/25, all bilaterally. The 2024/2025 MISO Planning Resource Auction results are not yet available. The offer window closes March 29 and results are to be posted April 26, after which time Big Rivers will evaluate future planning years' capacity needs and the best approach to resolving them.

Witness: Terry Wright, Jr.

IN THE MATTER OF
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

I, Christopher Bradley, verify, state, and affirm that the information request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Christopher Bradley
Vice President System Operations
Big Rivers Electric Corporation

STATE OF KENTUCKY)
) ss:
COUNTY OF DAVIESS)

14th SUBSCRIBED AND SWORN TO before me by Christopher Bradley on this the 14 day of February, 2024.

My commission expires: October 31, 2024

Notary Public

Notary ID: KYNP16841

IN THE MATTER OF
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

I, Nathanial A. Berry, verify, state, and affirm that the information request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Nathanial A. Berry
Chief Operating Officer
Big Rivers Electric Corporation

STATE OF KENTUCKY)
) ss:
COUNTY OF DAVIESS)

SUBSCRIBED AND SWORN TO before me by Nathanial A. Berry on this the 15 day of February, 2024.

My commission expires: 1-14-2026

Notary Public

Notary ID: KYNP43026

IN THE MATTER OF
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

I, Terry Wright, Jr., verify, state, and affirm that the information request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Terry Wright, Jr.
VP of Energy Services
Big Rivers Electric Corporation

STATE OF KENTUCKY)
) ss:
COUNTY OF DAVIESS)

SUBSCRIBED AND SWORN TO before me by Terry Wright, Jr. on this the 15 day of February, 2024.

My commission expires: 1-14-2026

Notary Public

Notary ID: KYNP43026

IN THE MATTER OF
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

I, Russell L. Pogue, verify, state, and affirm that the information request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Russell L. Pogue
Manager Power Marketing
and Member Relations
Big Rivers Electric Corporation

STATE OF KENTUCKY)
) ss:
COUNTY OF DAVIESS)

SUBSCRIBED AND SWORN TO before me by Russell L. Pogue on this the 15 day of February, 2024.

My commission expires: 1-14-2026

Notary Public

Notary ID: KYNP43026

IN THE MATTER OF
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

I, Michael S. Mizell, verify, state, and affirm that the information request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Michael S. Mizell
Chief Administrative Officer
Big Rivers Electric Corporation

STATE OF KENTUCKY)
) ss:
COUNTY OF DAVIESS)

15th SUBSCRIBED AND SWORN TO before me by Michael S. Mizell on this the 15th day of February, 2024.

My commission expires: October 31, 2024

Notary Public

Notary ID: KYNP16841

IN THE MATTER OF
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

I, Talina R. Mathews, verify, state, and affirm that the information request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Talina R. Mathews
Chief Financial Officer
Big Rivers Electric Corporation

STATE OF KENTUCKY)
) ss:
COUNTY OF DAVIESS)

SUBSCRIBED AND SWORN TO before me by Talina R. Mathews on this the 15th day of February, 2024.

My commission expires: October 31, 2024

Notary Public

Notary ID: KYNP16841

IN THE MATTER OF
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

I, John Christensen, verify, state, and affirm that the information request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

John Christensen
Senior Project Manager
Burns & McDonnell Engineering Co., Inc.

STATE OF Minnesota)
) ss:
COUNTY OF St. Louis)

9th SUBSCRIBED AND SWORN TO before me by John Christensen on this the day of February, 2024.

My commission expires: January 31st, 2027

ERIN KAYE JOHNSON
Notary Public-Minnesota
My Commission Expires Jan 31, 2027

Erin K. Johnson
Notary Public

Notary ID: 13076791000037

IN THE MATTER OF
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

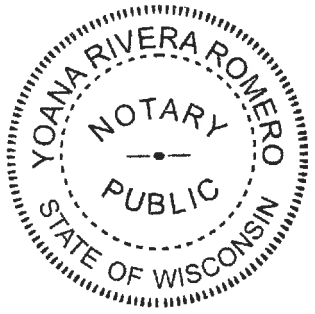
I, Joshua P. Hoyt, verify, state, and affirm that the information request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Joshua P. Hoyt
Principal Consultant
Clearspring Energy Advisors, LLC

STATE OF Wisconsin)
) ss:
COUNTY OF Dane)

SUBSCRIBED AND SWORN TO before me by Joshua P. Hoyt on this the 7 day of February, 2024.

My commission expires: Feb 14, 2027



Notary Public

Notary ID:_____

IN THE MATTER OF
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

I, Steven A. Fenrick, verify, state, and affirm that the information request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Steven A. Fenrick
Principal Consultant
Clearspring Energy Advisors, LLC

STATE OF Kentucky)
) ss:
COUNTY OF Jefferson)

12th SUBSCRIBED AND SWORN TO before me by Steven A. Fenrick on this the 12th day of February, 2024.

My commission expires: 11/22/2027

Notary Public

DANLIE QUIROGA MONTEJO
Notary Public - State at Large
Kentucky
My Commission Expires Nov. 22, 2027
Notary ID KYNP82990

Notary ID:

IN THE MATTER OF
ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2023-00310

BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION

I, Matthew Sekeres, verify, state, and affirm that the information request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Matthew Sekeres
Vice President
Clearspring Energy Advisors, LLC

STATE OF Wisconsin)
) ss:
COUNTY OF Rock)

NOTARY PUBLIC MELANIE DUNKIN STATE OF WISCONSIN

24th SUBSCRIBED AND SWORN TO before me by Matthew Sekeres on this the ___ day of February, 2024.

My commission expires: 04/19/2025

Notary Public

Notary ID: N/A