ORIGINAL

Your Touchstone Energy® Cooperative

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF	)	**Case No.**
BIG RIVERS ELECTRIC CORPORATION	)	**2020-00183**
FOR APPROVAL OF SOLAR POWER CONTRACTS	)	

Response to Commission Staff's
Initial Request for Information
dated August 5, 2020

FILED: August 14, 2020

ORIGINAL

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR APPROVAL OF SOLAR POWER CONTRACTS
CASE NO. 2020-00183

VERIFICATION

I, Mark J. Eacret, 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.

Mark J. Eacret

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Mark J. Eacret on this the 14th day of August, 2020.

Joy P. Parsley
Notary Public, Kentucky State at Large

My Commission Expires

Notary Public, Kentucky State-At-Large
My Commission Expires: July 10, 2022
ID: 604480

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR APPROVAL OF SOLAR POWER CONTRACTS
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VERIFICATION

I, Paul G. Smith, verify, state, and affirm that the supplemental data 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.

Paul Smith
____
Paul G. Smith

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Paul G. Smith on this the 14th day of August, 2020.

Joy P. Parsley
____
Notary Public, Kentucky State at Large

My Commission Expires ____________

Notary Public, Kentucky State-At-Large
My Commission Expires: July 10, 2022
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Item 1) ***Refer to the application, page 4, lines 19–21. Explain whether either the Kentucky Municipal Energy Agency (KyMEA) or Owensboro Municipal Utilities (OMU) have specifically requested a certain amount of renewable power from BREC.***

Response) Neither the KyMEA nor OMU have specifically requested a certain amount of renewable power from Big Rivers.

Witness) Mark J. Eacret

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Item 2) ***Refer to the application, page 6, lines 4–8. Explain whether BREC has any other specific customers for the solar power not consumed by Nucor.***

Response) Big Rivers has no other specific customers for the solar power not consumed by Nucor. For this reason, Big Rivers' plan is to sell the Renewable Energy Certificates (RECs), or other environmental attributes acquired through the contracts, and use the proceeds to reduce the costs of all of Big Rivers' Member-Owners.

Demand for renewable power is a growing trend in the electric industry, , and these low cost contracts will better position Big Rivers if and when Big Rivers receives such requests. In the meantime, these economic contracts will provide a benefit to the Member/Owners and their customers.

Witness) Mark J. Eacret

Item 3) ***Refer to the application, page 6, lines 18–21 through page 7, lines 1–2.***

a. Provide a copy of recent credit reports that support BREC's assertion that diversifying its supply portfolio enhances its credit.

b. Explain whether BREC has other economic development prospects that are interested in renewable power.

Response)

a. Please see Big Rivers' response to Item 33b of Commission Staff's Initial Request for Information for copies of the latest credit rating agency reports. A word search on "coal" in each of the documents will give one a sense of the respective credit rating agency's attitude towards Big Rivers' current resource mix. According to Standard and Poor's, one of the main (sub-investment grade) ratings drivers is "[t]he utility's almost exclusive reliance on coal-fired generation assets for the electricity it produces, tempered by market purchases that are produced with other fuels." Moody's describes "[e]levated carbon transition risk because of significant dependence on mostly coal-fired, carbon-emitting, owned generation capacity, including idled capacity" as a "credit challenge." In assigning Big Rivers an Operating Risk of 'a', Fitch writes, "[R]eliance on coal-fired capacity is lower than historical amounts and sits just below Fitch's threshold for a neutral assessment. Management expects to add some renewable (solar) capacity over the next several years, which will further diversify the resource base."

b. As was noted beginning on line 17, page 38 of my direct testimony, Big Rivers is seeing more economic development candidates directly request renewable energy or at least inquire about the renewable energy content of the Big Rivers resource portfolio. Economic development candidates are provided code names by the state Economic Development Board, so Big Rivers does not generally know the actual name of the candidate nor is Big Rivers always notified timely of a change in its status. Currently, however, Big Rivers believe that Project Green Arrow and Project Storage are active and have requested renewable energy as part of their supply.

Witnesses) Paul G. Smith (*a. only*) and
Mark J. Eacret (*b. only*)

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Item 4) ***Refer to the application, Exhibit 4, Direct Testimony of Mark Eacret (Eacret Testimony), page 6 of 40.***

a. Explain how the 260 megawatts (MW) solar purchase serves as a hedge of energy and capacity required to serve Nucor.

b. Explain the importance of the stated hedge price structure.

Response)

a. Under the Nucor agreement currently pending Commission approval,[1] [redacted]. Assuming the current MISO Business Practices Manual approach to solar capacity, 260 MW of solar will provide about 197 MW of capacity and 594 thousand MWh annually at a [redacted] price lower than what is being charged to Nucor. So the solar

[1] See *In the Matter of: Electronic Joint Application of Big Rivers Electric Corporation and Meade County Rural Electric Cooperative Corporation for (1) Approval of Contracts for Electric Service with Nucor Corporation; and (2) Approval of Tariff* – Case No. 2019-00365. Application filed October 18, 2019.

contracts could provide about [redacted] of the capacity and [redacted] of the energy required by Nucor at a price that locks in a positive margin.

b. Within a Regional Transmission Organization (RTO) like MISO, energy becomes fungible. Nucor has no right to the benefit of the solar contracts [redacted]. Therefore, the remaining benefit will flow to Big Rivers' Members either through Big Rivers' Fuel Adjustment Clause or the margin–sharing mechanism just approved by the Commission in 2020-00064.[2] Another part of that benefit will be a reduction in Big Rivers' market exposure, through a [redacted] purchase (the solar contracts) that substantially offsets a [redacted].

Witness) Mark J. Eacret

[2] See *In the Matter of: Electronic Application of Big Rivers Electric Corporation for Approval to Modify its MRSM Tariff, Cease Deferring Depreciation Expenses, Establish Regulatory Assets, Amortize Regulatory Assets, and Other Appropriate Relief* – Case No. 2020-00064. Application filed February 28, 2020.

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Item 5) ***Refer to the application, page 8, lines 14–18, page 10, lines 4–11, Eacret Testimony, page 14 of 40, lines 8–13, through 15 of 40, lines 1–14, and Exhibit Eacret-5.***

a. Provide Exhibit Eacret-5 with the addition of the solar contracts.

b. Explain how MISO counts capacity derived from solar generation.

c. Explain whether there are seasonal variations in the anticipated output and capacity value of the solar facilities.

d. Explain the differences between MISO's Business Practices Manual and MISO's proposed Effective Load Carrying Capability approaches to calculating capacity values.

e. Explain the status of MISO's proposed Effective Load Carrying Capability approach.

Response)

a. Please see Big Rivers' response to Item 17 of Commission Staff's Initial Request for Information in this case.

b. The current MISO Business Practices Manual ("BPM") approach is described in my direct testimony beginning on line 10 of page 32. In essence, MISO looks at the historical average of what the facility produces during the hours ended 15, 16, and 17 during the months of June through August.

c. Yes, there are seasonal variations in the output. See Exhibit A of each of the solar contracts for the projected generation shape under each. There are currently no seasonal capacity variations.

d. Effective Load Carrying Capability ("ELCC") is a methodology to determine the capacity credit of a resource by means of estimating the contribution that an individual generator makes to overall system resource adequacy. Specifically, ELCC is a measure of the additional load that the system can supply with the particular generator of interest, without a change in reliability. Consequently, the ELCC results are driven by the output of the generator of interest during hours with potentially high reliability risk. Such hours will vary based on the penetration level of solar and wind resources.

The difference between the two approaches is that the current BPM looks at the historical performance of the solar resource and bases future capacity value on that performance. Under ELCC, MISO evaluates the Loss of Load Expectation ("LOLE") with and without the resource going forward and determines how much the resource contributes to reducing the LOLE.

e. MISO currently applies ELCC to wind, and the Independent Market Monitor has suggested that applying the approach to solar should be evaluated. That suggestion is still in the study phase.

Witness) Mark J. Eacret

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Item 6) *Refer to the Eacret Testimony, page 6 of 40, lines 13–15. Provide the derivation of the approximate energy and capacity hedge percentages.*

Response) The three solar contracts are expected to provide a total of about [redacted] in their first year of operation. Nucor is expected to consume about [redacted]. That calculates to [redacted].

[redacted] / [redacted] = [redacted]

The [redacted] figure in my testimony is a typographical error.

Under the current MISO Business Practices Manual approach to determining the capacity value of solar resources, the solar contracts will provide about 197 MW of capacity in year two (Henderson 116 MW, Meade 31 MW, and McCracken 50 MW). Compared to the [redacted] Nucor requirement (including a planning reserve margin of 9.6%), the ratio is [redacted].

Witness) Mark J. Eacret

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Item 7) ***Refer to the Eacret Testimony, page 9 of 40, lines 8–25 through page 12 of 40, lines 1–11, and Exhibit Eacret-4. Provide the bid evaluation analysis that supports the referenced discussion and Exhibit.***

Response) **CONFIDENTIAL** Exhibit Eacret-4 filed with my direct testimony describes the screening process that was used to review the initial responses and create the short list presented on page 3 of that exhibit. The **CONFIDENTIAL** attachments hereto describe the evaluation process used to reduce the short list to the finalists.

Witness) Mark J. Eacret

Item 8) ***Refer to the Eacret Testimony, page 10 of 40. Provide a more detailed explanation of the meaning of and the implications for BREC of the statements on lines 6–12.***

Response) Each hour in MISO, market participants buy all of their energy requirements from MISO and sell all of their generation to MISO. If the purchase price of the load is exactly the same as the sales price of the generation, the two will offset and the result will be that the market participant serves its load at its cost of generation.

However, the load price and the generation price are rarely exactly the same and the difference between them is referred to as a basis. The basis is made up of congestion and losses between where the energy is generated and where it is consumed. While there are methods to manage the congestion component of the basis, as a general rule, a lower basis makes a generation resource a better hedge of a load obligation. Big Rivers' primary purposes for entering into the solar contracts are to fulfill its obligation in the proposed Nucor Agreement and to create a low-cost source of energy, or hedge, for its Member-Owners.

The ACES study referenced in lines 6 through 12 on page 10 of 40 estimated the price that would be received for the solar generation at the short-listed sites and compared it to the projected price that Big Rivers would pay for its load (the BREC.BREC pricing node). The ACES study did not identify any abnormal basis issues for any of the projects, at least in part because the solar generation sites were spread over the entire Big Rivers footprint.

Witness) Mark J. Eacret

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Item 9) ***Refer to the Eacret Testimony, page 10 of 40, line 22. Provide the results of MISO interconnection studies, if available, and explain whether there are any mitigating measures that must be taken to maintain the integrity of the transmission system.***

Response) MISO interconnection studies are not yet available. Geronimo filed for an interconnection agreement on June 22, 2020, and Community Energy filed for an interconnection agreement on June 18, 2020.

Witness) Mark J. Eacret

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Item 10) ***Refer to the Eacret Testimony, page 11 of 40. Elaborate on the concerns that BREC had with multiple parties sharing generation from a single facility.***

Response) Big Rivers' biggest concern in this regard is that it would have no control over with whom Big Rivers might be sharing the output of the single facility. There may be times when some sort of joint project with another counterparty might make sense. However, just within the past several years, Big Rivers has been, or is, involved in three proceedings before the Kentucky Public Service Commission ("Commission") (Case No. 2016–00278,[1] Case No. 2018-00146,[2] and Case No. 2019–00269[3]), a proceeding before the Federal Energy Regulatory Commission, and several Kentucky circuit court proceedings that illustrate the cost of such arrangements when disputes arise in such joint projects.

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[1] See *In the Matter of: Application of Big Rivers Electric Corporation for a Declaratory Order* – Case No. 2016-00278. Application filed July 29, 2016.

[2] See *In the Matter of: Notice of Termination of Contracts and Application of Big Rivers Electric Corporation for a Declaratory Order and for Authority to Establish a Regulatory Asset* – Case No. 2018-00146. Application filed May 1, 2018.

[3] See *In the Matter of: Electronic Application Of Big Rivers Electric Corporation For Enforcement of Rate and Service Standards* – Case No. 2019-00269. Application filed July 31, 2019.

Witness) Mark J. Eacret

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Item 11) ***Refer to the Eacret Testimony, page 11 of 40. Explain BREC's concerns regarding Geronimo's intention to construct a 160 MW facility.***

Response) See Big Rivers' response to Item 10 of the Commission Staff's Initial Request for Information in this case.

Witness) Mark J. Eacret

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Item 12) ***Refer to the Eacret Testimony, page 12 of 40. Explain how the two CES facility locations "diversifies LMP basis risk."***

Response) See the Big Rivers' response to Item 8 of Commission Staff's Initial Information Requests in this case for an overview of basis between Big Rivers' generating resources and Big Rivers' load. As described in that response, Big Rivers does not anticipate any significant basis risk between the new solar resources and Big Rivers' load. However, to the extent that such basis risk does exist, spreading 100 MW over two sites over two hundred miles apart should minimize that risk. Any transmission system issues that might cause congestion are unlikely to affect both sites simultaneously.

Witness) Mark J. Eacret

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Item 13) ***Refer to the Eacret Testimony, page 12 of 40. Provide a description of the resource planning model scenarios (including the optional resources offered for model selection) in a manner similar to what BREC provided in its most recent Integrated Resource Plan (IRP) that were examined relative to the solar purchases, where the model continued to select the solar purchases.***

Response) The twenty-nine (29) resource planning model scenarios (sensitivities) are listed and explained on page 2 of Exhibit Eacret-12 of my direct testimony under "What sensitivities were run on the LT plan model?" The LT Plan model had five (5) optional resources that are listed on page 1 of Exhibit Eacret-12 under New Resources Available. Please see Exhibit Eacret-12A and the Table entitled "LT Plan Results Summary – Capacity Addition, MW." The LT Model results in that table show the full amount of solar capacity allowed (300 MW) is added in all but eight sensitivities – where the natural gas combined cycle (NGCC) is more profitable during higher LMP prices (20%, 30%, 40% and 50% higher) and lower NG prices (20%, 30%, 40% and 50% lower).

In Big Rivers' 2017 Integrated Resource Plan, a solar fixed unit, *i.e.*, Big Rivers builds and owns the solar unit, was evaluated as a resource option but was not included as a least–cost option. A solar fixed unit was also included in the current models and, again, was not found to be as a least–cost option.

Witness) Mark J. Eacret

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Item 14) ***Refer to the Eacret Testimony, page 14. Explain whether BREC expects the non-renewal of the OMU and KMEA contracts.***

Response) The OMU contract is in the third month of a seventy-nine month term and the KyMEA agreement is in the fifteenth month of a one hundred twenty month term. So, renewal discussions with OMU and KyMEA are premature. While Big Rivers intends to pursue renewals, it does not assume renewals in its long-term planning.

Witness) Mark J. Eacret

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Item 15) ***Refer to the Eacret Testimony, page 16 of 40, lines 2–19. The Commission is aware of a possible renewable power contract between city of Henderson and a merchant solar provider. Explain whether BREC is aware of any system integration or stability issues, such as maintaining voltage and thermal limits, would occur for itself or MISO when this additional facility comes online.***

Response) Big Rivers is aware that Community Energy Solar is developing a solar generation facility for Henderson Municipal Power and Light near Henderson. While Big Rivers has not been provided any details on this project, Big Rivers is not aware of any system integration or stability issues created by this facility. Big Rivers expects that any such issues will be identified by MISO as the System Impact Studies are completed.

Witness) Mark J. Eacret

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Item 16) ***Refer to the Eacret Testimony, page 15 of 40. Provide the projected remaining lives for each of BREC's generating resources.***

Response) Coleman Units 1, 2, and 3 and Reid Unit 1 will be retired later in 2020. The estimated retirement years for each of Big Rivers' other generating resources are 2031 for the Reid Combustion Turbine, 2041 for Green Units 1-2, and 2045 for the Wilson Generating Station. However, Big Rivers will be filing its 2020 Integrated Resource Plan ("IRP") in late September and the final analysis in that IRP may change some of these estimated remaining lives.

Witness) Mark J. Eacret

Item 17) ***Refer to the application, Eacret testimony, page 15 of 40, and Eacret Exhibit-5.***

a. Provide an updated table with Zonal Resource Credits and along with the equivalent measures for each generating unit beginning in 2017 through 2032. Along with the table, explain the effects of the purchase on reserve margin.

b. Explain and provide additional support for how the solar energy becomes an economic energy purchase.

c. Provide an updated example of FAC filings (or FAC support documentation) that will be used to document and support the economic energy purchase monthly.

d. Explain how the cost of the purchased solar energy will be reduced by the value of capacity, ancillary services, and environmental attributes and how these cost reductions will be documented in the monthly FAC filings or support documentation.

Response)

a. Please see the attachment to this response, and refer to the rows entitled 'Required Planning Reserves' and 'Actual Planning Reserves.' When including the ELCC capacity value of the solar contracts (see Exhibit Eacret–14 filed with my direct testimony), reserve margins remain in line with MISO requirements ('Required Planning Reserves' row) through 2026, other than a shortage in 2022 when deliveries to Nucor Corporation begin. As the Owensboro Municipal Utilities ("OMU") and the Kentucky Municipal Energy Agency ("KyMEA") contracts expire in 2026 and 2029, reserve margins grow and exceed requirements by about [redacted]. This additional capacity towards the end of the decade gives Big Rivers the flexibility for load growth or to extend the OMU and/or KYMEA contracts, and provides some protection against environmental regulations that could force derates or retirement of Big Rivers' Green or Wilson generating assets.

b. Big Rivers defines "economic energy" as energy with a cost lower than the energy market price. Refer to the *__Revised__* Exhibit Eacret–15 provided in Big Rivers' response to Item 25 of Commission Staff's Initial Request for Information in this case. Big Rivers expects to pay a time-weighted average price of about [redacted] over the twenty–year terms of the solar agreements, after adjusting for the [redacted]. The market value of the energy produced by the solar facilities over the same time period is expected to be [redacted], based upon current forward price curves. Just from that perspective, the contracts create value for Big Rivers' Member-Owners. Additionally, Big Rivers' Member-Owners will have the right to sell the Renewable Energy Certificates associated with the solar projects, which are expected to have a value of between [redacted] (again, over the twenty–year term of the solar contracts). These proceeds reduce the cost per MWh of the energy even further below market. The Big Rivers analysis did not assign any value to other rights under the contracts such as ancillary services or other environmental attributes (carbon credits). If the MISO tariff changes or new government regulations increase the value of those rights, that makes the solar contract purchases even more economic.

While capacity values are usually not expressed in MWh terms, Big Rivers expects to receive additional value of between [redacted] over the twenty-year term, depending on capacity forward curves and whether the current MISO Business Practices Manual or the Effective Load Carrying Capability approaches are assumed. Notably, none of that has any impact on whether Big Rivers' Green or Wilson units run. If these units can continue to produce economic energy at margins high enough to cover their fixed costs, they will continue to operate and provide value for Big Rivers' Member-Owners.

c. Big Rivers' monthly FAC Form A Filing will not require any updates or modifications to account for the economic solar energy purchases. The energy cost of the monthly solar energy purchases will be included on Page 2, Fuel Cost Schedule, of Big Rivers' monthly Form A Filing, in the "Net energy cost – economy purchases" line item. The costs associated with solar energy purchases made to serve off-system sales, or for sales to which Big Rivers' FAC does not apply, will be included in the "Inter-System Sales Including Interchange-out" line on Big Rivers' Fuel Cost Schedule and subtracted from the total costs recoverable through Big Rivers' FAC.

Detail of the solar energy purchase costs included in Big Rivers' monthly FAC calculations will be provided in Big Rivers' monthly Form B Filing with the Commission, on the Power Transaction Schedule.

d. The value of the capacity, ancillary services, and environmental attributes will be marketable commodities that Big Rivers will be able to monetize thereby enhancing gross margins and increasing net margins. The increased net margins will result in an increased TIER credit, as approved in Case No. 2020-00064, which will create additional amortization of the regulatory assets (with Commission approval) and additional bill credits returned to members via Rider MRSM. Such benefits will not be documented in the monthly FAC filings.

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Witnesses) Mark J. Eacret (*a. and b. only*) and
Paul G. Smith (*c. and d. only*)

Item 18) ***Refer to the Eacret Testimony, page 16 of 40, lines 2–19. If the Commission approves BREC's solar contract applications, explain whether the addition of any additional renewable generation on BREC's system would present problems in maintaining the planning reserve margin and operating the MISO system in BREC's Zone at acceptable voltage and thermal limits. If so, explain what those problems are and how they could be resolved.***

Response) Big Rivers sees no issues in maintaining an appropriate planning reserve margin created by any additional renewable generation on Big Rivers' system. Specific to the proposed Big Rivers solar contracts, the MISO generator interconnection study process is designed to ensure acceptable voltage and thermal limits are maintained.

The addition of renewable generation under the proposed solar contracts would not present problems operating the MISO system in Big Rivers' Zone at acceptable voltage and thermal limits.

Issues could arise if MISO is saturated with high levels of renewable generation, renewable generation levels of 50% or higher. However, currently (as of

2020), the renewable generation on the MISO system in Big Rivers' Zone is not anywhere close to "high levels of renewable generation."

Witness) Mark J. Eacret

Item 19) ***Refer to the Eacret Testimony, page 16 of 40.***

a. ***Explain whether MISO is actively discouraging or not approving renewable energy projects for interconnection that would push the percentage of renewable generation above the 30 percent threshold***

b. ***Provide a detailed explanation of the integration and reliability problems that occur when more of the amount of renewable energy exceeds the 30 percent threshold.***

c. ***Explain how BREC will treat the energy potential and capacity of its existing generation units if all 260 MW of solar energy is being purchased***.

Response)

a. No, MISO is not discouraging renewable energy projects. In announcing its 2020 Interconnection Queue Application results on August 2 of this year, a MISO spokesman noted, "The trends represented among the 2020 GIQ applicants indicate robust interest in development of new interconnection projects that will adequately support future resource needs. The MISO resource fleet continues to experience a shift from predominately conventional generation to renewable technologies as a result of customer preference, regulatory policy and economic drivers." MISO further noted that the MISO queue "now consists of 756 projects totaling 113 GW – 64 percent of which is solar. MISO is currently managing 13 ongoing queue cycles with another cycle set to start within the next year." For further information see:

https://www.misoenergy.org/about/media-center/giq-results/.

That said, the MISO real-time fuel mix in 2020 has been about 12% wind, and solar is not even presented separately yet. While that is a record number, there is still quite a way to go before we see 30% to 40%.

b. In his testimony before Congress regarding 30% renewable integration referenced on page 12 in my direct testimony, Mr. John R. Bear, MISO's Chief Executive Officer, states further that "at the 40% renewable penetration level becomes significantly more complex. In addition to the challenges described at the 30% level, we would encounter the need to balance the system over a very large area to reduce renewable curtailments and regional transmission reliability issues. The system stability issues would drive the need for non-traditional transmission devices like High Voltage Direct Current (HVDC) lines or other advanced technologies. We are currently looking at the implications of a 50% renewable penetration level." Please see Big Rivers' response to Item 18 of Commission Staff's Initial Information Request in this case for further information on how Big Rivers is and will be addressing transmission implications of increased renewable generation.

c. The solar contracts will have absolutely no impact on how the existing Big Rivers generation fleet will operate. Big Rivers will continue to submit Wilson, both Green units, and the Reid combustion turbine into the MISO capacity markets. Big Rivers will continue to offer the resources into the MISO energy market each day, and if the units can operate below the MISO hourly market prices, they will run.

Big Rivers is currently preparing its 2020 Integrated Resource Plan ("2020 IRP") for submission to the Commission in late September. That 2020 IRP will evaluate, as it does every three years, whether existing generation is projected to be competitive over the next twenty years. That analysis is not yet complete, but market prices and capital costs driven by environmental regulations will drive whether the existing generation runs, not the solar contracts.

Witness) Mark J. Eacret

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Item 20) ***Refer to the Eacret Testimony, page 17 of 40. Referencing the article regarding National Grid's problems with solar projects in the link below, describe Geronimo's relationship to National Grid and whether BREC is aware of any negative issues associated with Geronimo renewable project implementation. https://www.utilitydive.com/news/alleged-national-grid-management-problems-at-the-highest-levels-prompt-ma/564938/***

Response) According to information provided by Geronimo, Geronimo Energy LLC (Geronimo) is a wholly owned subsidiary of National Grid PLC (NG) and is organized under National Grid's Ventures Division (NGV), which includes other unregulated NG subsidiaries. Geronimo is a full-service developer, builder and operator of wind and solar energy facilities throughout the United States. The article noted above refers to NG's retail distribution utility in Massachusetts, which has the obligation to deliver retail energy to end-use customers and to allow distributed energy projects such as small solar projects to interconnect to their distribution system. The issues discussed in the article surround Massachusetts regulators' concerns about delays in

NG's process to allow solar projects to interconnect. Geronimo is not a party to these concerns or the Massachusetts regulatory investigation.

Geronimo Energy, as an Independent Power Producer, follows Regional Transmission Organizations' (RTOs) or individual utilities' processes to interconnect its projects to the transmission or distribution grid. The Henderson Solar Project is active in the MISO interconnection queue as part Central-DPP Cycle 1 and will interconnect at the Reid Substation.

Big Rivers is not aware of any negative issues associated with Geronimo renewable project implementation

Witness) Mark J. Eacret

Item 21) ***Refer to the Eacret Testimony, page 18 of 40 and page 23 of 40.***

a. ***Confirm that BREC will purchase the output, which includes the energy, ancillary services, and all environmental rights from the solar facility.***

b. ***Explain the ancillary services associated with the solar facility output and how BREC's members will benefit from those services.***

Response)

a. Yes, Big Rivers will receive all energy, capacity, ancillary services, and environmental rights produced by the solar facilities.

b. As was noted on page 29 of 40 of my testimony, while Big Rivers is entitled to any ancillary services revenues from the solar facilities, Big Rivers does not expect these revenues to be significant under the current MISO tariff and assumed their value to be zero in its economic analysis.

Witness) Mark J. Eacret

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Item 22) ***Refer to the Eacret Testimony, page 18 of 40 and page 20 of 40. Explain whether BREC acting as the Market Participant means that the three solar providers are technically selling the output into MISO and BREC is buying it back according to the contract pricing arrangements regardless of MISO hourly locational marginal prices.***

Response) No, as the Market Participant, Big Rivers will receive directly all MISO revenue for energy, capacity, and ancillary services created by the output of the solar facilities. Big Rivers will pay Geronimo and Community Energy the contract price for all MWhs produced, regardless of the MISO hourly locational marginal prices realized by Big Rivers for that output.

Witness) Mark J. Eacret

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Item 23) ***Refer to the Eacret Testimony, page 20 of 40, lines 1–4. Explain how BREC will shadow settle the expected MISO energy, capacity, and ancillary service revenues.***

Response) Shadow settling is the process of taking meter data and MISO energy market information to estimate a MISO settlement statement prior to receiving the settlement statement. The actual settlement statement is then compared to the estimate for accuracy.

ACES Power Marketing, on behalf of Big Rivers, has software that it uses to shadow settlement MISO activities including energy, capacity, and ancillary services revenue. Big Rivers will be the market participant in MISO and will set up the solar generation as a separate asset owner. This means that MISO will provide a distinctive settlement statement for this activity that the ACES software can shadow.

Witness) Mark J. Eacret

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Item 24) ***Refer to the Eacret Testimony, page 20 of 40. Provide any estimations of interconnection costs for each project.***

Response) Under the Henderson County Solar/Geronimo agreement, the seller bears the risk of interconnection costs and Big Rivers has seen no estimates of these costs. Under each of the Meade County Solar and McCracken County Solar/Community Energy Solar agreements, the seller bears the risk of the first $300,000 in interconnection costs. Beyond that, Big Rivers would bear the risk of the next $1.0 million in interconnection costs under each agreement, for a total risk of $2.0 million. While Big Rivers has seen no formal estimates of such interconnection costs, because both the Meade and McCracken facilities are connecting at a sub-transmission level, the costs are expected to be $300 thousand dollars or less for each project.

Witness) Mark J. Eacret

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Item 25) ***Refer to the Eacret Testimony, page 29, lines 1–4 and Exhibit Eacret-15. If not provided elsewhere, provide a copy of the economic analysis in electronic format with all cells and formulas visible and unprotected.***

Response) Please see the **CONFIDENTIAL** Excel file of *Revised* Exhibit Eacret-15 provided with these responses.

Witness) Mark J. Eacret

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Item 26) ***Refer to the Eacret Testimony, page 29. Explain why the model selects solar until the maximum reserve margin is reached.***

Response) The LT Plan model solves the capacity addition or capacity subtraction equations and provides a least–cost plan solution. Because the sum of the value of the energy, capacity, and environmental attributes obtained for each solar MWh is higher than the contract price paid, each additional solar MW reduces cost further. The LT Plan model will evaluate all resource options and if each additional solar project reduces cost further, it will continue to add solar projects until a maximum is reached. In this case, that maximum is established by the reserve margin.[1]

Witness) Mark J. Eacret

[1] Please see the **CONFIDENTIAL** Exhibit Eacret 12 to Big Rivers' Application in this case, at page three (3) for specific information regarding the reserve margin.

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Item 27) ***Refer to the Eacret Testimony, page 30 of 40, lines 20–23 through page 32, lines 1–8. Provide a numerical example of the calculations described in the discussion.***

Response) The **CONFIDENTIAL** attachment to this response presents the calculation of the market value of projected 2024 energy. The attachment is taken from *Revised* Exhibit Eacret–15 filed with Big Rivers' response to Item 15 of Commission Staff's Initial Request for Information.

Witness) Mark J. Eacret

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Item 28) ***Refer to the Eacret Testimony, page 40 of 40. Describe any potential costs of renegotiation of contracts.***

Response) The largest potential cost would be the loss of the Nucor investment in Kentucky, the $1.35 billion dollar investment, the 400 well-paying jobs, and the associated economic activity in the region. To avoid that outcome, Big Rivers would likely be forced into contract concessions to Nucor and the solar developers, which, while difficult to quantify in advance, would erode the benefit that Big Rivers' existing Members would otherwise realize from the Nucor and solar contracts.

As noted in Big Rivers' response to Item 29 of Commission Staff's Initial Information Requests, upon Commission approval of the Nucor Agreement, Nucor will pay a [redacted]. The [redacted] solar contracts would serve as a partial hedge of that exposure. Without the solar contracts, Big Rivers would be forced to find other hedges. Because the projected market value of the energy, capacity, and environmental attributes exceed the contract prices, the alternative hedges would by definition be more expensive than the solar contracts.

If Big Rivers is unable to secure approval of the solar contracts and, consequently, would need to renegotiate the Nucor contract, the credit rating agencies would view this result negatively. First, the loss of some or all of the entire value of the Nucor agreement as discussed above would harm Big Rivers' future earnings. Second, the loss of the diversification of Big Rivers' resource portfolio would harm Big Rivers from an Environmental, Social, and Governance (ESG) perspective.

Further, the loss of the solar contracts prevents the anticipated reduction of Big Rivers' Members' costs. The loss of that cost reduction, makes Big Rivers' Members marginally less competitive against neighboring utilities.

Witness) Mark J. Eacret

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Item 29) ***Refer to the Eacret Testimony, page 40 of 40. Provide the actual flat rates charged to OMU and the expected rates to be charged to Nucor.***

Response) Under the OMU contract dated June 22, 2018, and approved by the Commission on July 27, 2018, (TFS 2018-00318), OMU pays Big Rivers [redacted]. The Big Rivers agreement with OMU expires on December 31, 2026.

Under the Nucor contract pending before the Commission in Case No. 2019-00365,[1] Nucor will pay Meade County RECC [redacted].

Witness) Mark J. Eacret

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[1] See *In the Matter of: Electronic Joint Application of Big Rivers Electric Corporation and Meade County Rural Electric Cooperative Corporation for (1) Approval of Contracts for Electric Service with Nucor Corporation; and (2) Approval of Tariff* – Case No. 2019-00365. Application filed October 18, 2019.

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Item 30) ***Refer to the Eacret Testimony generally. Explain whether BREC has other customers that want or need renewable energy to satisfy sustainable energy goals.***

Response) Currently, none of Big Rivers' Member-Owners have directly expressed a want or need for renewable energy to satisfy sustainable energy goals to Big Rivers. That is why Big Rivers' plan is to sell the Renewable Energy Certificates (RECs) or other environmental attributes acquired through the solar contracts and use the proceeds to reduce the costs of all of our Members.

Demand for renewable energy is a growing trend in the electric industry, and these solar contracts will better position Big Rivers if and when it begins to receive such requests.

Witness) Mark J. Eacret

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Item 31) ***Refer to the Eacret Testimony, Exhibit Eacret-12. Provide a more detailed explanation of the differences between the Plexos LT Plan and ST Plan models and how each model approached the analyses.***

Response) The LT Plan model is a capacity planning model and its objective is to provide the least–cost plan or portfolio by minimizing the net present value of the production and capital cost for serving a load. The LT Plan model evaluates the generation resource options (current generators, build options, and retire options) and solves the capacity addition or capacity subtraction equation (least–cost plan) for the load being served. The minimum and maximum capacity reserve margins are provided as inputs to the LT Plan model. In Exhibit Eacret-12, the LT Plan Results Summary table is displaying the capacity additions for the base case and scenarios.

The ST Plan model is an hourly dispatch model and provides results for known resources. The ST Plan model does not solve the capacity addition or subtraction equation. A ST Plan model was built with the five new generation resources (PPA –

Solar BREC, PPA – Solar 25, NGCC,[1] Solar Fixed,[2] and NGCT[3]) and the model dispatched and provided results for these resources for the 20–year period from 2024-2043. Exhibit Eacret-12B provided with my direct testimony displays the ranking of these new resources utilizing the ST Plan modeling results.

Witness) Mark J. Eacret

[1] NGCC – Natural Gas Combined Cycle.

[2] Solar Fixed = A solar unit which Big Rivers builds and owns.

[3] NGCT – Natural Gas Combustion Turbine.

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Item 32) ***Refer to the application, page 13, Footnote 10, and Exhibit 5, Direct Testimony of Paul G. Smith (Smith Testimony), page 7 of 8, lines 2-7.***

a. ***Explain the reasoning behind S&P rating agency's treating 25-50 percent of BREC's payments under the contracts as fixed charges when calculating various coverage ratios and, if possible, provide a copy of S&P's report to BREC explaining its rationale.***

b. ***Explain whether the rating agencies would treat any other BREC contracted market power purchase the same way.***

Response)

a. See the attached publication, "*Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements*."

b. Not all rating agencies treat long-term agreements similarly. However, based on the attached publication, it appears S&P would treat a long-term fixed price power purchase contract the same way.

Witness) Paul G. Smith

STANDARD
&POOR'S

RATINGSDIRECT®

May 7, 2007

Criteria | Corporates | Utilities:

Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements

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Witness: Paul G. Smith

Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements

For many years, Standard & Poor's Ratings Services has viewed power supply agreements (PPA) in the U.S. utility sector as creating fixed, debt-like, financial obligations that represent substitutes for debt-financed capital investments in generation capacity. In a sense, a utility that has entered into a PPA has contracted with a supplier to make the financial investment on its behalf. Consequently, PPA fixed obligations, in the form of capacity payments, merit inclusion in a utility's financial metrics as though they are part of a utility's permanent capital structure and are incorporated in our assessment of a utility's creditworthiness.

We adjust utilities' financial metrics, incorporating PPA fixed obligations, so that we can compare companies that finance and build generation capacity and those that purchase capacity to satisfy customer needs. The analytical goal of our financial adjustments for PPAs is to reflect fixed obligations in a way that depicts the credit exposure that is added by PPAs. That said, PPAs also benefit utilities that enter into contracts with suppliers because PPAs will typically shift various risks to the suppliers, such as construction risk and most of the operating risk. PPAs can also provide utilities with asset diversity that might not have been achievable through self-build. The principal risk borne by a utility that relies on PPAs is the recovery of the financial obligation in rates.

The Mechanics Of PPA Debt Imputation

A starting point for calculating the debt to be imputed for PPA-related fixed obligations can be found among the "commitments and contingencies" in the notes to a utility's financial statements. We calculate a net present value (NPV) of the stream of the outstanding contracts' capacity payments reported in the financial statements as the foundation of our financial adjustments.

The notes to the financial statements enumerate capacity payments for the five years succeeding the annual report and a "thereafter" period. While we have access to proprietary forecasts that show the detail underlying the costs that are amalgamated beyond the five-year horizon, others, for purposes of calculating an NPV, can divide the amount reported as "thereafter" by the average of the capacity payments in the preceding five years to derive an approximate tenor of the amounts combined as the sum of the obligations beyond the fifth year.

In calculating debt equivalents, we also include new contracts that will commence during the forecast period. Such contracts aren't reflected in the notes to the financial statements, but relevant information regarding these contracts are provided to us on a confidential basis. If a contract has been executed but the energy will not flow until some later period, we won't impute debt for that contract until the year that energy deliveries begin under the contract if the contract represents incremental capacity. However, to the extent that the contract will simply replace an expiring contract, we will impute debt as though the future contract is a continuation of the existing contract.

We calculate the NPV of capacity payments using a discount rate equivalent to the company's average cost of debt, net of securitization debt. Once we arrive at the NPV, we apply a risk factor, as is discussed below, to reflect the benefits of regulatory or legislative cost recovery mechanisms.

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Balance sheet debt is increased by the risk-factor-adjusted NPV of the stream of capacity payments. We derive an adjusted debt-to-capitalization ratio by adding the adjusted NPV to both the numerator and the denominator of that ratio.

We calculate an implied interest expense for the imputed debt by multiplying the same utility average cost of debt used as the discount rate in the NPV calculation by the amount of imputed debt. The adjusted FFO-to-interest expense ratio is calculated by adding the implied interest expense to both the numerator and denominator of the equation. We also add implied depreciation to the equation's numerator. We calculate the adjusted FFO-to-total-debt ratio by adding imputed debt to the equation's denominator and an implied depreciation expense to its numerator.

Our adjusted cash flow credit metrics include a depreciation expense adjustment to FFO. This adjustment represents a vehicle for capturing the ownership-like attributes of the contracted asset and tempers the effects of imputation on the cash flow ratios. We derive the depreciation expense adjustment by multiplying the relevant year's capacity payment obligation by the risk factor and then subtracting the implied PPA-related interest expense for that year from the product of the risk factor times the scheduled capacity payment.

Risk Factors

The NPVs that Standard & Poor's calculates to adjust reported financial metrics to capture PPA capacity payments are multiplied by risk factors. These risk factors typically range between 0% to 50%, but can be as high as 100%. Risk factors are inversely related to the strength and availability of regulatory or legislative vehicles for the recovery of the capacity costs associated with power supply arrangements. The strongest recovery mechanisms translate into the smallest risk factors. A 100% risk factor would signify that all risk related to contractual obligations rests on the company with no mitigating regulatory or legislative support.

For example, an unregulated energy company that has entered into a tolling arrangement with a third-party supplier would be assigned a 100% risk factor. Conversely, a 0% risk factor indicates that the burden of the contractual payments rests solely with ratepayers. This type of arrangement is frequently found among regulated utilities that act as conduits for the delivery of a third party's electricity and essentially deliver power, collect charges, and remit revenues to the suppliers. These utilities have typically been directed to sell all their generation assets, are barred from developing new generation assets, and the power supplied to their customers is sourced through a state auction or third parties, leaving the utilities to act as intermediaries between retail customers and the electricity suppliers.

Intermediate degrees of recovery risk are presented by a number of regulatory and legislative mechanisms. For example, some regulators use a utility's rate case to establish base rates that provide for the recovery of the fixed costs created by PPAs. Although we see this type of mechanism as generally supportive of credit quality, the fact remains that the utility will need to litigate the right to recover costs and the prudence of PPA capacity payments in successive rate cases to ensure ongoing recovery of its fixed costs. For such a PPA, we employ a 50% risk factor. In cases where a regulator has established a power cost adjustment mechanism that recovers all prudent PPA costs, we employ a risk factor of 25% because the recovery hurdle is lower than it is for a utility that must litigate time and again its right to recover costs.

We recognize that there are certain jurisdictions that have true-up mechanisms that are more favorable and frequent than the review of base rates, but still don't amount to pure pass-through mechanisms. Some of these mechanisms

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are triggered when certain financial thresholds are met or after prescribed periods of time have passed. In these instances, in calculating adjusted ratios, we will employ a risk factor between the revised 25% risk factors for utilities with power cost adjustment mechanisms and 50%.

Finally, we view legislatively created cost recovery mechanisms as longer lasting and more resilient to change than regulatory cost recovery vehicles. Consequently, such mechanisms lead to risk factors between 0% and 15%, depending on the legislative provisions for cost recovery and the supply function borne by the utility. Legislative guarantees of complete and timely recovery of costs are particularly important to achieving the lowest risk factors.

Illustration Of The PPA Adjustment Methodology

The calculations of the debt equivalents, implied interest expense, depreciation expense, and adjusted financial metrics, using risk factors, are illustrated in the following example:

Example Of Power-Purchase Agreement Adjustment

($000s)	Assumption	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Cash from operations	2,000,000						
Funds from operations	1,500,000						
Interest expense	444,000						
Directly issued debt							
Short-term debt	600,000						
Long-term due within one year	300,000						
Long-term debt	6,500,000						
Shareholder's Equity	6,000,000						
Fixed capacity commitments	600,000	600,000	600,000	600,000	600,000	600,000	4,200,000*
NPV of fixed capacity commitments							
Using a 6.0% discount rate	5,030,306						
Application of an assumed 25% risk factor	1,257,577						
Implied interest expense¶	75,455						
Implied depreciation expense	74,545						
Unadjusted ratios							
FFO to interest (x)	4.4						
FFO to total Debt (%)	20.0						
Debt to capitalization (%)	55.0						
Ratios adjusted for debt imputation							
FFO to interest (x)§	4.0						
FFO to total debt (%)**	18.0						
Debt to capitalization (%)¶¶	59.0						

*Thereafter approximate years: 7. ¶The current year's implied interest is subtracted from the product of the risk factor multiplied by the current year's capacity payment. §Adds implied interest to the numerator and denominator and adds implied depreciation to FFO. **Adds implied depreciation expense to FFO and implied debt to reported debt. ¶¶Adds implied debt to both the numerator and the denominator. FFO--Funds from operations. NPV--Net present value.

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Short-Term Contracts

Standard & Poor's has abandoned its historical practice of not imputing debt for contracts with terms of three years or less. However, we understand that there are some utilities that use short-term PPAs of approximately one year or less as gap fillers pending the construction of new capacity. To the extent that such short-term supply arrangements represent a nominal percentage of demand and serve the purposes described above, we will neither impute debt for such contracts nor provide evergreen treatment to such contracts.

Evergreen Treatment

The NPV of the fixed obligations associated with a portfolio of short-term or intermediate-term contracts can lead to distortions in a utility's financial profile relative to the NPV of the fixed obligations of a utility with a portfolio of PPAs that is made up of longer-term commitments. Where there is the potential for such distortions, rating committees will consider evergreen treatment of existing PPA obligations as a scenario for inclusion in the rating analysis. Evergreen treatment extends the tenor of short- and intermediate-term contracts to reflect the long-term obligation of electric utilities to meet their customers' demand for electricity.

While we have concluded that there is a limited pool of utilities whose portfolios of existing and projected PPAs don't meaningfully correspond to long-term load serving obligations, we will nevertheless apply evergreen treatment in those cases where the portfolio of existing and projected PPAs is inconsistent with long-term load-serving obligations. A blanket application of evergreen treatment is not warranted.

To provide evergreen treatment, Standard & Poor's starts by looking at the tenor of outstanding PPAs. Others can look to the "commitments and contingencies" in the notes to a utility's financial statements to derive an approximate tenor of the contracts. If we conclude that the duration of PPAs is short relative to our targeted tenor, we would then add capacity payments until the targeted tenor is achieved. Based on our analysis of several companies, we have determined that the evergreen extension of the tenor of existing contracts and anticipated contracts should extend contracts to a common length of about 12 years.

The price for the capacity that we add will be derived from new peaker entry economics. We use empirical data to establish the cost of developing new peaking capacity and reflect regional differences in our analysis. The cost of new capacity is translated into a dollars per kilowatt-year (kW-year) figure using a weighted average cost of capital for the utility and a proxy capital recovery period.

Analytical Treatment Of Contracts With All-In Energy Prices

The pricing for some PPA contracts is stated as a single, all-in energy price. Standard & Poor's considers an implied capacity price that funds the recovery of the supplier's capital investment to be subsumed within the all-in energy price. Consequently, we use a proxy capacity charge, stated in $/kW, to calculate an implied capacity payment associated with the PPA. The $/kW figure is multiplied by the number of kilowatts under contract. In cases of resources such as wind power that exhibit very low capacity factors, we will adjust the kilowatts under contract to reflect the anticipated capacity factor that the resource is expected to achieve.

We derive the proxy cost of capacity using empirical data evidencing the cost of developing new peaking capacity.

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We will reflect regional differences in our analysis. The cost of new capacity is translated into a $/kW figure using a weighted average cost of capital and a proxy capital recovery period. This number will be updated from time to time to reflect prevailing costs for the development and financing of the marginal unit, a combustion turbine.

Transmission Arrangements

In recent years, some utilities have entered into long-term transmission contracts in lieu of building generation. In some cases, these contracts provide access to specific power plants, while other transmission arrangements provide access to competitive wholesale electricity markets. We have concluded that these types of transmission arrangements represent extensions of the power plants to which they are connected or the markets that they serve. Irrespective of whether these transmission lines are integral to the delivery of power from a specific plant or are conduits to wholesale markets, we view these arrangements as exhibiting very strong parallels to PPAs as a substitute for investment in power plants. Consequently, we will impute debt for the fixed costs associated with long-term transmission contracts.

PPAs Treated As Leases

Several utilities have reported that their accountants dictate that certain PPAs need to be treated as leases for accounting purposes due to the tenor of the PPA or the residual value of the asset upon the PPA's expiration. We have consistently taken the position that companies should identify those capacity charges that are subject to operating lease treatment in the financial statements so that we can accord PPA treatment to those obligations, in lieu of lease treatment. That is, PPAs that receive operating lease treatment for accounting purposes won't be subject to a 100% risk factor for analytical purposes as though they were leases. Rather, the NPV of the stream of capacity payments associated with these PPAs will be reduced by the risk factor that is applied to the utility's other PPA commitments. PPAs that are treated as capital leases for accounting purposes will not receive PPA treatment because capital lease treatment indicates that the plant under contract economically "belongs" to the utility.

Evaluating The Effect Of PPAs

Though history is on the side of full cost recovery, PPAs nevertheless add financial obligations that heighten financial risk. Yet, we apply risk factors that reduce debt imputation to recognize that utilities that rely on PPAs transfer significant risks to ratepayers and suppliers.

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The McGraw·Hill Companies

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Item 33) ***Refer to the Smith Testimony, page 8 of 8, lines 4-17.***

a. ***Explain how the Solar Contract's improvement of Environmental, social, and governance rating criteria count as mitigating factors and the extent to which these mitigating factors help offset the negative effects of S&P's treatment of the payments under the contracts.***

b. ***Provide copies of the latest rating agency reports.***

Response)

a. S&P evaluates numerous subjective and objective criteria when assigning a credit rating. Theoretically, enhancing Big Rivers' Environmental, Social, and Governance criteria should mitigate a slightly declining objective criteria, such as the debt service coverage ratio.

b. Please see the three attached rating agency reports.

Witness) Paul G. Smith

S&P Global Ratings

RatingsDirect®

Big Rivers Electric Corp., Kentucky Ohio County; Rural Electric Coop

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Attachment 1 for Response to PSC 1-33b

Witness: Paul G. Smith

Big Rivers Electric Corp., Kentucky Ohio County; Rural Electric Coop

Credit Profile		
Big Rivers Electric Corp. ICR		
Long Term Rating	BB+/Stable	Affirmed
Ohio Cnty, Kentucky		
Big Rivers Electric Corp., Kentucky		
Ohio Cnty (Big Rivers Electric Corp.) RURELCCOO		
Long Term Rating	BB+/Stable	Affirmed

Rating Action

S&P Global Ratings affirmed its 'BB+' issuer credit rating on Big Rivers Electric Corp. (BREC), Ky. At the same time, S&P Global Ratings affirmed its 'BB+' rating on Ohio County, Ky.'s $83.3 million pollution control refunding revenue bonds, series 2010A (Big Rivers Electric Corp. Project), issued for BREC. The outlook on all ratings is stable.

Credit overview

BREC is a generation and transmission cooperative serving three member distribution cooperatives. Key rating drivers include:

- The wholesale utility's reliance on significant, but declining, market sales where the utility is a price-taker;
- The short tenor of five wholesale power contracts with nonmembers that will help displace market sales;
- The meaningful contributions of industrial customers to its member distribution cooperatives' revenues, which we view as an exposure because of illness related to the coronavirus and measures taken to limit the outbreak, which are taking a toll on economic activity; and
- The utility's almost exclusive reliance on coal-fired generation assets for the electricity it produces, tempered by market purchases that are produced with other fuels.

Moreover, we believe that although projected debt service coverage (DSC) ratios of at least 1.4x in 2020-2021 are robust, they do not fully compensate for the exposures the utility faces. We also take into consideration nonamortizing debt representing 35% of the utility's debt portfolio, which enhances the DSC ratios by approximately 30 basis points compared with a fully amortizing scenario.

Members provided 72% of 2018's operating revenues and revenues from the sale of surplus energy production in competitive wholesale markets provided nearly 30%. BREC projects market revenues will decline to less than 4% by 2023 as its members add steel manufacturer Nucor Corp. as a customer and multi-year contracts between BREC and municipal utility systems begin. Although Energy Information Administration (EIA) data shows that members' energy sales to industrial customers account for 75% of energy sales, BREC reports that it transmits power others produce to two smelter customers and that those sales should be excluded from member energy sales. This adjustment halves

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members' energy sales to industrial customers. Adding Nucor will raise industrial concentration to about 50% of member energy sales. The industrial concentration is mitigated by plans to not earn a margin on half of the energy it sells to Nucor. BREC projects that once Nucor opens a new facility within the service territory of distribution member Meade County Rural Electric Cooperative Corp., which it plans to do in 2022, it will help absorb surplus capacity and increase member sales revenues by more than 20%. Although BREC projects the Nucor facility will add a 200-megawatt (MW) load, at the same time, adding the company will expand the customer base's industrial concentration. We view the Nucor load as providing a cushion that can help mitigate any nonrenewals by the municipal contract customers.

BREC has added contracts with municipal utilities that are providing greater and more stable revenues than market sales. These contracts and the Nucor addition will almost eliminate exposure to market sales by 2022. However, because of their tenor, the nonmember contracts will provide only medium-term revenue stream security and predictability. The municipal contracts expire in 2026 and 2029, with 240 MW of the contracted capacity rolling off in 2026 and another 100 MW in 2029. Nucor's 200 MW load should help temper the possibility that BREC is unable to renew the municipal contracts. BREC reports nearly 1,200 MW of generation capacity.

Unlike many other cooperative utilities, BREC does not have autonomous rate-setting authority. Rather, the Kentucky Public Service Commission establishes the cooperative's wholesale rates and its members' retail rates. Tempering the absence of rate-setting autonomy is a history of supportive regulatory decisions and utility projections that assume that BREC will not need rate increases through 2027.

Environmental, social and governance factors

We believe BREC's generation fleet presents meaningful environmental exposures as the national focus on reducing greenhouse gas emissions advances, which could jeopardize generator dispatch and financial performance. The utility's use of coal to produce electricity represented nearly 100% of the utility's self-generation in 2019 and 80% of the electricity BREC sold that year.

Although EIA data show that the residential rates BREC's members charge their customers were 13%-18% higher than the state average in 2018, BREC reports that the EIA data does not reflect member bill credits tied to the use of its rate stabilization fund, which reduce rates by about 5%. Applying this discount, we nevertheless believe the utility presents social risk that could limit financial flexibility, especially in light of income levels and the negative economic pressures of directives to limit the spread of coronavirus. The rate disparities reflect BREC's allocation to remaining customers, and costs from smelter loads lost in 2013. Before their departure, the smelters accounted for about two-thirds of BREC's energy sales. Although the duration of the recently negotiated nonmember contracts is relatively short, we believe that management is mitigating governance risk through efforts to secure purchasers for the surplus capacity that customer departures created. The utility also benefits from a proactive regulator that in addition to overseeing the utility's rates, has demonstrated a commitment to monitoring management and board actions.

Stable Two-Year Outlook

The stable outlook reflects improved prospects for stable financial performance with the anticipated addition of the Nucor load and the medium-term municipal contracts to sell surplus power to nonmember public power utilities. We

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view these developments as sharply reducing BREC's exposure to market prices for energy sales, at least through the life of the contracts.

Downside scenario

We could lower the ratings if the utility cannot sustain sound financial performance because of poor prospects for renewing or replacing nonmember contracts, weak market conditions, or poor plant performance. Similarly, if the financial profiles of BREC's members erode, we could lower the ratings. We could also lower the ratings if declining economic activity attributable to the outbreak of coronavirus or measures limiting the spread of COVID-19 negatively affect financial margins.

Upside scenario

We do not expect to raise the ratings within our two-year outlook horizon without prospects for a more secure long-term revenue stream that aligns predictable revenues with debt maturities. We view several additional exposures as constraining the ratings. These include rates we consider high relative to low income levels; an almost exclusively coal-fired generation portfolio and its exposure to more stringent emissions regulations; the presence of nonamortizing debt, which we believe distorts DSC levels relative to utilities with greater percentages of amortizing debt; meaningful industrial loads in a declining economy; and DSC levels that do not compensate fully for these exposures.

Credit Opinion

BREC reported $733 million of debt as of Dec. 31, 2019. About 35% of its debt will not amortize before maturity, which contributes to more robust DSC ratios, relative to utilities with a greater percentage of amortizing debt. The cooperative projects adding 26% more debt through 2021, bringing debt balances up to $921 million. Nevertheless, the utility projects maintaining a favorable debt-to-capitalization ratio for a cooperative utility of 67% in 2021. The aging generation units help reduce the debt to capitalization ratios. With the debt additions, the utility projects robust DSC metrics of at least 1.4x through 2022. We performed a scenario analysis that suggests that coverage would be about 30 basis points lower if the cooperative had a fully amortizing debt portfolio.

Although we view coverage levels and liquidity as providing resilience, our rating conclusions assign significant weight to the relative brevity of the municipal power sales agreements. If BREC is unable to renew these contracts and must rely on market sales for margins, we believe the utility could be vulnerable to earning comparatively thin margins in competitive markets, compared with those it earns under the municipal contracts. At the same time, we view favorably the addition of Nucor as a members' customer, as helping reduce market exposure. Additional factors we view as constraining the rating include the industrial concentration among members' customers, and members' high retail rates that can limit financial flexibility when viewed through the lens of the state's low income levels.

We view external liquidity facilities as providing an added measure of lender protection. External facilities increase balance-sheet liquidity from a weak 40 days' operating expenses to about four months' operating expenses.

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CREDIT OPINION
13 November 2019

Update

Rate this Research

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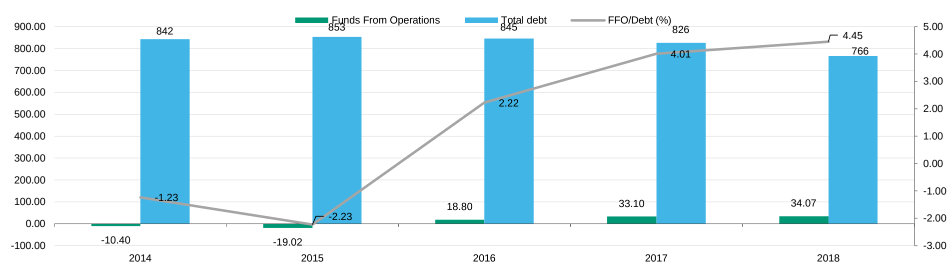
Big Rivers Electric Corporation

Update following outlook change to positive

Summary

Big Rivers Electric Corporation's (Ba1 positive) credit profile reflects improving prospects for mitigating the challenges posed by its ownership of a significant excess of mostly coal-fired generation capacity, some of which is idled, and its increasing regulatory asset balances. Big Rivers' credit profile considers the fact that it is a rate regulated electric generation and transmission cooperative as compared to its peers, but this consideration is balanced by a series of credit supportive decisions from the Kentucky Public Service Commission (KPSC) which has underpinned its strengthened financial metrics for 2016-18. Big Rivers' credit profile benefits from the ability to secure steadily increasing replacement loads following the termination of contracts with two aluminum smelters, including contracts that will continue to be phased in through 2022. Additionally, the cooperative is undertaking strategies to mitigate future refinancing risk relating to two long-term debt issues with bullet maturities due in 2023 and 2031 and to seek assurances for cost recovery relating to its increasing regulatory assets in a rate neutral manner through regulatory filings with the KPSC.

Exhibit 1
Historical FFO, Total Debt and FFO to Total Debt
($ in millions)



Source: Moody's Financial Metrics

Credit Strengths

» Contracted sales of excess capacity are being phased in over the next several years, including sales to a prospective steel plate manufacturing plant to be built by Nucor Corporation

» Limited new debt financing needs to support a moderate capital program, reliable net margins and no patronage capital returns to members support a strong balance sheet

» Regulatory support for timely and substantial recovery of existing costs of service bodes well for sustaining stronger financial metrics

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» Long term wholesale power contracts with three member owners through 2043 produce a steady and predictable revenue stream from electricity sold to rural residential and other non-smelter industrial customers

Credit Challenges

» Maintaining customer satisfaction as bill credits have expired and the full impact of increases to the members' wholesale power rate has increased retail rates for members' customers

» Increasing regulatory assets pose potential cost recovery and write-off risks if not adequately addressed as expected through regulatory proceedings

» Elevated carbon transition risk because of significant dependence on mostly coal-fired, carbon-emitting, owned generation capacity, including idled capacity

» Executing strategies to address refinancing risk relating to two bullet maturities of long-term debt and sizable debt maturities beyond the term of certain existing power sales agreements with replacement loads following termination of contracts with the two aluminum smelters

» Local economic dependence on industrial activity, including two operating aluminum smelters and the prospective steel plate manufacturing plant to be built by Nucor

Rating Outlook

The positive rating outlook reflects a prevailing credit supportive regulatory environment and Big Rivers' improving prospects for sustaining its financial metrics at the stronger levels attained during 2016-18 while continuing to achieve better than expected progress in reducing its significant excess capacity created by the lost smelters load several years ago. The positive outlook also considers the cooperative's good prospects for reducing refinancing risk and limited new debt financing needs during the next three years, and incorporates the likelihood that the smelters will continue to operate and that the Nucor load will materialize, thus providing support for the local economy, including employment levels.

Factors that Could Lead to an Upgrade

» A rating upgrade is possible if credit supportive regulatory treatment remains intact and there is future regulatory support for cost recovery of the increasing regulatory asset account which would avoid potential future write-offs while maintaining reasonably competitive rates

» Achieving further successful financial results through ongoing strategies to mitigate refinancing risk and to better align the cooperative's capacity supply and load profile on a sustainable basis could also contribute to upward rating pressure

» Achieving stronger metrics to balance unique business and financial risks; for example, funds from operations (FFO) coverage of interest and debt improving to 2.4x and in a range of 6%-7%, respectively, with the debt service coverage (DSC) ratio tracking at close to 1.2x or better on a sustained basis

Factors that Could Lead to a Downgrade

» A negative rating action is unlikely in the next two years because of the positive outlook; However, a negative rating action could result if there was a shift to a less credit supportive regulatory environment or if liquidity unexpectedly deteriorates

» The pressure for a negative rating action would also increase if substantial and timely assurance for recovery of environmental compliance costs and increasing regulatory assets over time do not occur as expected under the KPSC approved environmental cost recovery mechanism and future KPSC regulatory proceedings

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- A scenario under which either or both of the smelters discontinued operations or if the Nucor Corporation load does not materialize would be credit negative because of the potential residual negative effects on the local economy
- In terms of metrics, FFO to debt and DSC ratios below 4% and 1.2x, respectively, for a sustained period would pressure the rating

Key Indicators

Exhibit 2

Big Rivers Electric Corporation
Key Indicators

	2014	2015	2016	2017	2018
Times Interest Earned Ratio (TIER)	1.6x	1.3x	1.1x	1.3x	1.4x
DSC (Debt Service Coverage)	1.5x	1.2x	1.2x	1.2x	1.2x
FFO / Debt	-1.2%	-2.2%	2.2%	4.0%	4.4%
(FFO + Interest Expense) / Interest Expense	0.7x	0.5x	1.5x	1.8x	1.9x
Equity / Total Capitalization	34.9%	35.3%	36.0%	37.2%	39.6%

Source: Moody's Financial Metrics

Obligor Profile

Big Rivers is an electric generation and transmission cooperative headquartered in Henderson, Kentucky and owned by its three member system distribution cooperatives -- Jackson Purchase Energy Corporation; Kenergy Corp (Kenergy); and Meade County Rural Electric Cooperative Corporation (Meade County). These member system cooperatives provide retail electric power and energy to more than 116,000 residential, commercial, and industrial customers in 22 Western Kentucky counties.

In aggregate, Big Rivers owns 1,444 net MWs of coal-fired generating capacity at four stations, including Robert D. Green (454 MWs), Robert A. Reid ((130 MWs), D.B. Wilson (417 MWs) and Kenneth C. Coleman (443 MWs), which has been idled since May 2014. Including about 178 MWs of contracted hydro capacity from the Southeastern Power Administration (SEPA) and taking into account the decision to cease operations at the Henderson Municipal Power and Light (HMPL) Station Two plant thus eliminating its rights to about 187 MWs of coal-fired capacity from that plant, the cooperative's total power capacity is 1,622 MWs.

Big Rivers' owned transmission system includes 1,298 miles of transmission lines and 24 substations. The cooperative also has about 25 transmission interconnections to link its system with several surrounding utilities. Unlike most of its peers, Big Rivers is subject to rate regulation by the KPSC.

Detailed Credit Considerations

Good progress on mitigating credit challenges resulting from loss of aluminum smelters' load

Big Rivers has been making good progress towards replacing the roughly two-thirds of its annual energy sales from two aluminum smelters. While initial worst case expectations contemplated the prospect that both smelters would cease operations upon the expiration of their respective power contracts, regulatory approvals of the smelters' definitive agreements with Big Rivers and Kenergy enable the continued operations of both smelters with energy demands met by open market purchases of electricity. Big Rivers is addressing the long generation capacity position created by the absence of both smelters' load through both supply-side and demand-side strategies, as well as by reducing staff and controlling other expenses where feasible without compromising reliability.

Supply-side strategies taken to another level during 2018-2019

Big Rivers' supply-side initiatives included idling its 443-MWs Coleman plant in May 2014 and terminating its operating agreement with HMPL during 2018, which led to the closure of the HMPL Station Two plant on January 31, 2019. The latter steps reduced the cooperative's excess capacity by eliminating its rights to about 187 MWs of competitively challenged coal-fired capacity from the HMPL Station Two plant.

The settlement agreement to end the operating agreement with HMPL, which was approved by the KPSC on an expedited basis during 2018, provides Big Rivers the ability to apply regulatory asset treatment for its approximately $90 million of net book value relating to its past investments in the Station Two plant as part of the operating agreement. The settlement also established a times interest

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earned ratio (TIER) credit, which allows Big Rivers to apply any 2019 and 2020 margins in excess of a 1.45 TIER as an initial amortization of its regulatory asset balance. It is management's intent to seek recovery of the regulatory assets in regulatory proceedings likely to be filed at the KPSC no later than early 2020.

Although the Coleman plant was idled in May 2014, it is being maintained to permit restart should market conditions become economically feasible. By idling the Coleman plant, Big Rivers achieved overall cost savings of about $26 million annually. Big Rivers is reporting internal load growth and longer term opportunities are arising for sales of electricity, resulting from economic development activity in its service territory. For example, Big Rivers has an industrial customer utilizing the cooperative's economic development incentive rate in its business expansion, which will contribute significant growth to the cooperative's load. Also, in March 2019 Nucor Corporation (Baa1 stable) announced it plans to construct a steel plate manufacturing mill in Meade County's service territory. More recently, in September 2019 Meade County, Big Rivers and Nucor all signed a long-term power purchase agreement that will add about 200 MWs of load by 2022 to be served by Big Rivers, effectively establishing Nucor as one of Meade County's members. The Nucor plant will also provide additional economic stimulus within the service territory.

Also, Big Rivers is considering the transfer of some environmental control equipment at the Coleman plant to its Wilson plant. If this strategy is successfully implemented, it is likely to reduce the financial impact of a potential write-off or the need for regulatory asset recovery if management elects to permanently shutter the Coleman plant in the future. The current net book value of the Coleman plant, including deferred depreciation, is estimated at $181 million. The net book value includes approximately $73 million of investments in scrubbers. The remaining amounts of net investment in both the Coleman and Station Two plants represent potential write-off risks to Big Rivers' common equity if the cooperative is not able to recover the remaining costs from its customers as a regulatory asset.

The fact that the HMPL Station Two settlement was unanimously supported by the Attorney General (AG) and the Kentucky Industrial Utility Customers (KIUC) is a credit positive. In doing so, the AG and KIUC agreed to support recovery of Station Two and Wilson Station regulatory assets in Big Rivers' next base rate case, with the AG's support contingent on any proposed rate impact being 0% or less. Also, the KIUC has agreed to support recovery of the Coleman Station regulatory asset, while the AG indicated neither support nor opposition to such recovery.

Demand-side strategies are phasing in according to plans and are enhanced by the signing of the contract with Nucor

Big Rivers' demand-side strategies include securing medium-term contracts for the sale of capacity and energy to load serving municipal-distribution entities in Nebraska and Kentucky, making short-term off system sales and participating in the capacity markets.

In addition, the Nucor contract, which is still subject to various regulatory approvals, would add to the three nine-year contracts that the cooperative already has in place to sell capacity and energy to three Nebraska entities which will grow to about 85 MWs. Power being provided under the contract with the Nebraska entities began flowing in 2018 and is scheduled to reach full output in 2022. Also, Big Rivers has executed a 10-year contract to transmit as much as 100 MWs from its coal-fired Wilson Station to Kentucky Municipal Energy Agency (KyMEA) and sales to KyMEA began in May 2019. Also, in June 2018, the City of Owensboro awarded its full-requirements contract, approximating 180 MWs to Big Rivers, which together with other supply-side efforts, helps to further balance Big Rivers' generation capacity and load requirement. The contract with the City of Owensboro covers a term of June 2020 through December 2026 to provide the municipal utility's full annual energy requirements estimated at 825,000 megawatt hours and annual peak load of about 155 MWs, net of its 25 MWs provided through a contract with the Southeast Power Administration.

These contracts are credit positive for Big Rivers because they lock up some of its substantial excess capacity and energy with load-serving municipal-distribution entities for multiple year periods, helping the cooperative replenish the smelter load lost during 2013-14. The contracts are likely to prove beneficial for Big Rivers' long-term financial performance and provide a reliable source of recovery for Big Rivers' fixed and variable costs and contribute to its overall competitiveness through better rates for its members. Also, the contracts allow Big Rivers to become less dependent on the wholesale power market for incremental revenues and helps diversify the cooperative's revenue stream, which historically was heavily dependent on the aluminum industry, to one that is less volatile and more predictable.

Setting aside the still idled Coleman capacity and considering the effects of terminating the operating agreement with HMPL, BREC has just under 1,200 MWs of capacity and awaits the outcome of its RFP for up to 250 MWs of solar capacity. This level of capacity

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compares with average member peak load of 650 MWs and when combined with additional aforementioned contracted capacity sales of about 550 MWs phasing in through 2022 and allocating about 150 MWs for an approximate 15% reserve margin, moves Big Rivers very close to achieving supply and demand balance.

Smelters continue to operate and the Hawesville smelter moves closer to operating at full capacity

Since canceling their respective contracts, both of the smelters continue to operate. We understand that the Hawesville smelter has gradually ramped up operations in recent years because of some economic aid and improved commodity pricing for aluminum and currently is operating at about 80% of its capacity with four of its five pot lines operating. Also, the Hawesville smelter is continuing work during 2019 to get the fifth pot line operational. The Sebree smelter has been operating at near full production capacity for several years. When compared to the alternative scenario of having both smelters permanently shut down, this outcome is positive particularly since Big Rivers and Kenergy are being reimbursed for any incremental costs to their members of the smelters' continued operation and there are residual benefits to the local economy.

Rate case decisions and ongoing cost recovery mechanisms remain credit positive factors

Big Rivers has approval from the US Department of Agriculture's Rural Utilities Service (RUS) for loans to be funded no later than December 2023 which would provide reimbursement for certain transmission asset investments already made and to refinance half of its Series B Note which has a $245.5 million balloon payment due in December 2023, while it intends to repay the other half of the Series B Note with cash. Additional refinancing strategies are likely to include a reoffering of its $83.3 million of County of Ohio, Kentucky Pollution Control Refunding Revenue Bonds (Big Rivers Electric Corporation Project) in July 2020 to achieve an estimated net present value of $20 million interest expense savings. The pollution control bonds have a July 2020 call date.

Also, Big Rivers' credit profile benefits from credit supportive rate case decisions rendered by the KPSC in October 2013 and April 2014, which resulted in approval of a combined wholesale power rate increase of about $90.4 million. As part of these decisions, residual cash, set aside in restricted accounts, was supportive to Big Rivers' liquidity after the loss of the smelter load. Specifically, cash in the restricted accounts was used to provide bill credits during 2014-16, which minimized the rate shock to ratepayers until September 2015 for large industrial/business (non-smelter) customers and until August 2016 for rural (residential) customers. With the expiration of bill credits in 2016, the full effects of the wholesale power rate increases are now being fully borne by Big Rivers' members and, in turn, the members' retail customers.

Overall credit positive impact from KPSC mandated independent management audit

The KPSC ordered independent consultant's comprehensive management audit is credit positive for Big Rivers since it incorporates a combination of many supportive or neutral findings about Big Rivers' past decisions and future plans, as well as five specific, seemingly manageable, recommendations. Of those five recommendations, four were already in process as of the report date, including those relating to increasing expertise regarding the MISO market, pursuing new energy sales and analyzing the best use of the currently idled Coleman plant. Three of the five action items have been closed by the KPSC, including an agreement that the recommendation of adding a new board member with energy expertise is not warranted, that Big Rivers was sufficiently pursuing new energy sales, and that Big Rivers has sufficiently added staff resources focusing on enhancing internal expertise in production cost and financial modeling to further leverage its association as a member of ACES.

The remaining two items yet to be closed by the KPSC relate to: (1) the executed amendments made to Big Rivers' debt documents to address restrictions around the sale or early retirement of the Coleman plant, and (2) completion of the study of the sale, retirement or redevelopment of the Coleman plant.

Reasonably competitive position maintained

As depicted in exhibit three below, although Big Rivers' rates have increased following the loss of the smelter loads, the economics of power produced from Big Rivers' generation sources have enabled it to still maintain a reasonable competitive position in the region.

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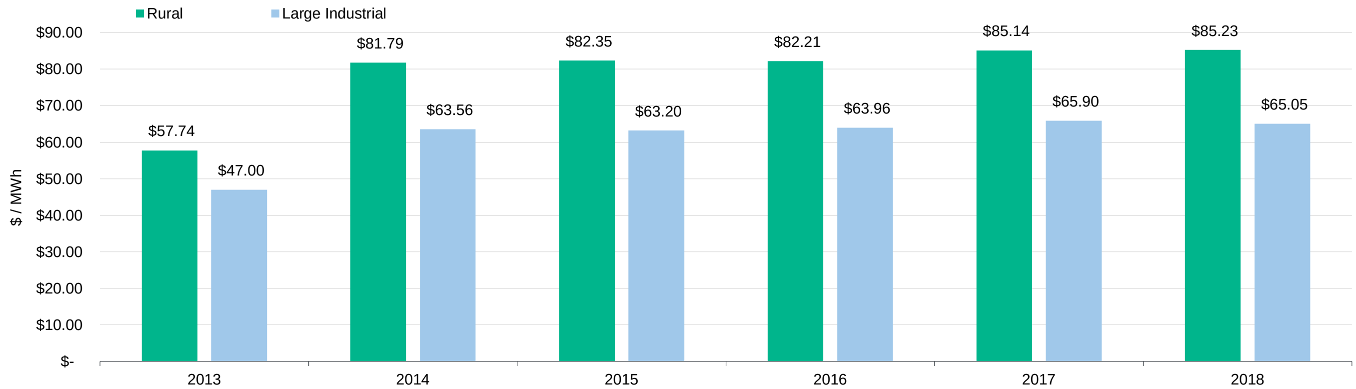
Exhibit 3
Historical Average Member Rates



Source: Big Rivers Electric Corporation

Base rate increases from 2013 and 2014 and other strategic initiatives are driving improved financial performance and this trend is likely to be sustained

The outcomes in Big Rivers' last two rate cases and other mitigation strategies have supported steady margins for the past three fiscal years in a range of approximately $12.9 - $15.2 million. The net margin for fiscal year ended December 31, 2018 was $15.2 million, representing modest improvement over the prior two years and produced a 1.39x TIER, a contractual margins for interest (MFI) ratio of 1.39x and a DSC ratio of 1.22x, all as defined in the cooperative's debt documents.

Despite mild weather and soft wholesale market pricing, Big Rivers margins for the six months ended June 30, 2019 were $18.9 million compared to $15.6 million in the same period of 2018, primarily reflecting the cost savings from the January 31, 2019 closure of the Station Two plant. Net margin and cash flow benefits from the Station Two plant closure are likely to continue throughout fiscal year 2019 and beyond.

For fiscal years 2016-18 (including Moody's standard adjustments), Big Rivers' FFO coverage of interest, FFO to debt and DSC ratios averaged in the “Baa”, “Baa” and “A” rating categories, respectively, for the ratios covered under the Rating Methodology for U.S. Electric G&T Cooperatives. For example, Big Rivers' three year average FFO coverage of interest, FFO to Debt, and DSC for 2016-18 were 1.7x, 3.5%, and 1.2x, respectively.

Big Rivers' FFO coverage of interest and debt ratios strengthened during fiscal years 2016-18 and prospectively are likely to be sustained to support the cooperative's credit quality as power sales agreements with entities in Nebraska and Kentucky and the recent long-term contract with Nucor help compensate for the substantial overcapacity at Big Rivers.

Liquidity

We expect that Big Rivers will maintain ample liquidity over the next 12-18 months.

Big Rivers supplements its existing cash on hand and internally generated cash flow with a multi-year $100 million syndicated senior secured credit agreement with five financial institutions, led by National Rural Utilities Cooperative Finance Corporation (NRUCFC), which expires September 18, 2020. Big Rivers plans to negotiate prior to the expiration date for either an amend and extend agreement or a new facility for at least the same amount and under similar terms and conditions for at least a three-year term.

As of June 30, 2019, Big Rivers had a cash and temporary investments balance of about $48.8 million and $92.3 million available under the NRUCFC credit agreement. Big Rivers is likely to have very limited need for new debt financing for the next eight quarters because of a modest capital spending program for maintenance of existing infrastructure and manageable debt maturities over the period. The debt maturities are largely comprised of scheduled amortizations of long-term debt to be paid at roughly $8 million - $10 million per quarter for the next eight quarters.

Terms of the NRUCFC credit agreement provide a good quality source of alternate liquidity in the form of a syndicated credit agreement. The facility does not have any onerous financial covenants, which are largely consistent with the financial covenants

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in existing debt documents. The syndicated agreement does, however, separately require Big Rivers to maintain a minimum equity balance at each fiscal quarter-end and year-end of $375 million plus 50% of the cooperative's cumulative positive net margins for each of the preceding fiscal years, beginning with the fiscal year ended December 31, 2015. Big Rivers is comfortably in compliance with those covenants. Additionally, the credit agreement benefits from no ongoing material adverse change (MAC) clause. The syndicated credit agreement does not have any rating triggers, just a pricing grid based on Big Rivers' rating.

Debt Structure

As part of the unwinding of various transactions completed in 2009, Big Rivers replaced the previously existing RUS mortgage with a senior secured indenture. Under the senior secured indenture RUS and all senior secured debt holders, including the $83.3 million of County of Ohio, Kentucky Pollution Control Refunding Revenue Bonds (Big Rivers Electric Corporation Project; cusip number 677288AG7), are on equal footing in terms of priority of claim and lien on assets. The current senior secured indenture provides Big Rivers with the flexibility to access public debt markets without first obtaining a case specific RUS lien accommodation, while retaining the right to request approval from the RUS for additional direct borrowings under the RUS loan program, if they choose to do so. Given persistent questions about the availability of funds under the federally subsidized RUS loan program, the added flexibility of the current senior secured indenture is credit positive.

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Other Considerations

Big Rivers' mapping under Moody's U.S. Electric Generation & Transmission Cooperative Rating Methodology scorecard below is based on historical data through December 31, 2018.

The scorecard-indicated outcome for Big Rivers' senior most obligations under the Methodology is currently Baa2. However, Big Rivers' actual senior secured rating of Ba1 reflects several of the unique risks at Big Rivers and the challenges facing the cooperative in mitigating these risks, including further implementation of its load mitigation strategies following the smelter contract terminations and addressing issues surrounding its increasing regulatory asset accounts and idled Coleman plant. The differential between the scorecard indicated outcome and the actual Ba1 senior secured rating is also reflected in the recent revision to a positive outlook to incorporate progress in addressing these challenges.

Methodology

Exhibit 4

Big Rivers Electric Corporation

Big Rivers Electric Corporation, KY -Private

U.S. Electric Generation & Transmission Cooperatives Industry Scorecard [1][2]	Current FY 12/31/2018		Moody's 12-18 Month Forward View As of Publication Date [3]	
Factor 1: Long-Term Wholesale Power Supply Contracts and Regulatory Status (20.0%)	**Measure**	**Score**	**Measure**	**Score**
a) % Member Load Served under Regulatory Status	Ba	Ba	Ba	Ba
Factor 2: Rate Flexibility (20.0%)				
a) Board Involvement / Variable Cost Adjustment Mechanisms	Baa	Baa	Baa	Baa
b) Purchased Power / Total MWh Sales (%)	17.9%	Aa	20% - 30%	A
c) New Build Exposure (% Net PP&E)	A	A	A	A
d) Potential for Rate Shock Exposure	B	B	B	B
Factor 3: Member / Owner Profile (10.0%)				
a) Residential Sales / Total Sales (%)	36.9%	Ba	25% - 35%	Ba
b) Members' Consolidated Equity / Capitalization (%)	37.8%	Baa	37% - 40%	Baa
Factor 4: 3-Year Average G&T Financial Metrics (40.0%)				
a) TIER (3 Year Avg)	1.3x	A	1.3x - 1.5x	Aa
b) DSC (3 Year Avg)	1.2x	A	1.2x - 1.5x	A
c) FFO / Debt (3 Year Avg)	3.5%	Baa	4% - 7%	Baa
d) (FFO + Interest) / Interest Expense (3 Year Avg)	1.7x	Baa	2x - 2.5x	A
e) Equity / Total Capitalization (3 Year Avg)	37.6%	Aa	37% - 41%	Aa
Factor 5: G&T Size (10.0%)				
a) Megawatt hour sales (Millions of MWhs)	6.4	Baa	7 - 10	Baa
b) Net PP&E (USD Billions)	$1.0	A	$0.9	Baa
Rating:				
a) Indicated Outcome from Scorecard		Baa2		Baa1
b) Actual Rating Assigned (Senior Secured)		Ba1		Ba1

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 12/31/2018; Source: Moody's Financial Metrics™
[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
Source: Moody's Investor Service

RATINGS

BIG RIVERS ELECTRIC CORPORATION, KY

Rating: County of Ohio, Kentucky Pollution Control Refunding Revenue Bonds (Big Rivers Electric Corporation Project; cusip number 677288AG7)	Ba1
Outlook	Positive

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Attachment 2 for Response to PSC 1-33b
Witness: Paul G. Smith

REPORT NUMBER 1198918

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CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

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FitchRatings

Fitch Affirms Big Rivers Electric Corp. at 'BBB-'; Outlook Stable

Fitch Ratings - New York - 04 December 2019:

Fitch Ratings has affirmed the ratings on the following bonds issued by Big Rivers Electric Corporation (BREC) at 'BBB-':

--$83 million County of Ohio pollution control revenue bonds, series 2010A.

--Issuer Default Rating (IDR).

ANALYTICAL CONCLUSION

The 'BBB-' rating and IDR on Big Rivers Electric Corporation reflects the corporation's elevated but improving leverage profile in relation to its midrange revenue defensibility and strong operating risk profile. Fitch assesses Big River's three members to have midrange credit quality, which coupled with the absence of independent rate-setting authority, constrains the corporation's overall revenue defensibility.

The rating also reflects the corporation's consistently low operating cost burden and supportive regulatory regime. Lastly, Fitch views favorably the re-balancing of Big River's previously long resource position through a combination of greater contracted non-member sales and the retiring and/or idling of existing capacity, which should allow financial margins to remain stable and operating costs low. If margins remain strong and leverage declines further, upward rating movement is possible.

CREDIT PROFILE

Big Rivers Electric Corporation, a non-profit generation and transmission (G&T) cooperative formed in 1961, provides all-requirements wholesale electric and transmission service to three electric distribution cooperatives pursuant to all-requirements contracts through Dec. 31, 2043. The three members provide service to a total of approximately 117,000 retail customers located in 22 western Kentucky counties. Financial performance of the three distribution systems is satisfactory and provides sufficient support for the rating.

KEY RATING DRIVERS

Revenue Defensibility:: 'bbb'

Strong Contractual Framework, Midrange Member Credit Quality

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Revenue defensibility is midrange despite otherwise very strong revenue source characteristics provided by all-requirements contracts. The midrange assessment principally reflects the credit quality of the three member utilities along with the regulatory framework within which Big Rivers and its customers operate. While the regulatory regime has been constructive historically, neither Big Rivers nor its three customers have autonomy over rate-setting.

Operating Risk:: 'a'

Coal-Dominated Resource Base, Low Cost Burden

The strong operating risk assessment begins with a low operating cost burden that has averaged 4.85 cents/KWh over the past five years. Operating cost flexibility assessment is neutral as Big River's has idled or retired 695 MWs of coal capacity over the past few years. As a result, reliance on coal-fired capacity is lower than historical amounts and sits just below Fitch's threshold for a neutral assessment. Management expects to add some renewable (solar) capacity over the next several years, which will further diversify the resource base.

Financial Profile:: 'bbb'

Improved Margins, Leverage to Decline

Big River's midrange financial profile reflects elevated but improving leverage ratios. The solid financial results achieved in fiscals 2017 and 2018 are expected to continue as Big Rivers provides contracted energy and capacity to Kentucky Municipal Energy Agency and the city of Owensboro, KY in 2019 and 2020, respectively. In addition, Fitch anticipates lower operating expenses from the reduction in capacity over the past few years coupled with higher non-cash expenses (depreciation) will lead to a further improvement in leverage over the next few years.

Asymmetric Additional Risk Considerations

There are no additional asymmetric risks affecting the rating.

RATING SENSITIVITIES

Improved Leverage: Big Rivers Electric Corporation's ratings and IDR could be upgraded if the financial profile is sustained and leverage continues its positive trend downward over time.

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Member Credit Quality: The rating is also sensitive to changes in the credit quality of its three member customers. A shift in member credit quality in either direction could result in a change in Fitch's assessment of revenue defensibility and could lead to a change in the rating.

SECURITY

The bonds are secured by a mortgage lien on substantially all of the Big Rivers' owned tangible assets, which include the revenue generated from the wholesale sale or transmission of electricity.

Revenue Defensibility

Strong Contractual Framework

Revenue source characteristics are very strong. All three of Big Rivers' customers are signed to long-term, all-requirements, take-and-pay power contracts. All costs associated with the delivery of power and energy/services, including debt service on the bonds, are billed to the customers on a monthly basis. There are no step-up provisions in the contracts for non-payment. However, given there are only three members, the rating on the bonds is heavily correlated to the credit quality of all three customers.

Rates are Regulated

The Kentucky Public Service Commission (KPSC) is charged with approving the wholesale and retail rates of Big Rivers' and its members. Wholesale rates charged to the members consist of a demand charge and an energy charge per kWh consumed as approved by KPSC. Big Rivers has certain approved riders including a fuel adjustment clause and an environmental surcharge, which helps provide timely pass-through of variable charges. Supportive regulatory policies and successful rate recovery efforts historically point to a constructive regulatory environment.

Big Rivers' last rate order, received in 2014, approved rates at levels that allowed it to cover total fixed costs on a self-sustaining basis. On the member level, rates are set for full cost recovery. However, while the regulatory environment for rate recovery has been supportive, approval of rate cases by an outside entity could result in delayed revenue recovery, potentially higher revenue variability and weaker overall revenue defensibility compared to non-regulated entities, and thus limits rate flexibility in Fitch's view.

Beginning in 2018, member rates have been set to allow Big Rivers to fully recover its costs from the members (i.e., there are no longer any deferred revenues), which is an important rating factor that underpins the investment grade rating. Fitch believes the stronger margins are sustainable over the intermediate term as Big Rivers begins to benefit for newly contracted sales. The average wholesale power cost to members declined in 2018 to $71/MWh from about $76/MWh the previous year. The member rate for 2019 is up to $72.50 and is forecast to rise again in 2020 to just over $73.00 but remain at this level for the next few years.

Midrange Purchaser Credit Quality

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Revenue defensibility primarily reflects the member (purchaser) credit quality as evaluated using Fitch's purchaser credit index (PCI), which reflects the weighted average credit quality of the relevant obligors. Fitch's PCI score of 3.05 is based on an evaluation of all three member cooperatives; Meade County Rural Cooperative Corporation (Meade), KY comprising 16% of Big River's revenues; Kenergy Corporation, KY (Kenergy, 63% of revenues); and Jackson Purchase Energy Corporation, KY (Jackson, 21% of revenues). The overall scoring for each cooperative ranged from relatively strong to relatively weak.

The PCI takes into account the strength of the member's service area, retail rate competitiveness and ability to absorb rate increases through an analysis of its service area, as well as 2018 financial performance. Fitch assessed the service area characteristics for the two largest members to be midrange based on the relatively low median household income (MHI) and average to above average unemployment rates.

Contributing to Kenergy's midrange score are its proportionally low amount of revenues derived from residential users (23% of total coop revenues) and MHI that is just 84% of the US average. In addition, 2018 financial performance was weak. On the positive side, Kenergy's customer base is slowly growing and retail rates are very affordable. The weak score for Jackson is rooted in its even lower MHI (74% of the U.S. average), relatively high unemployment rate of 6.1%, high retail rates, and very weak 2018 margin and cash cushion. Meade's score was assessed to be the highest of the three, although as the smallest of Big Rivers' members, its strong overall credit profile factors less into the overall PCI.

The three member cooperatives serve small to mid-sized cities and counties, and are geographically located on Kentucky's western border. Economic activity throughout the state is relatively diverse but weighted more heavily in manufacturing and natural resources. Locally, growth in the population and customer base has been steady and the unemployment levels for the communities, while varied, are mostly moderate ranging from 4.4% to as high as 6.1%. A fairly robust transportation network provides access to larger metropolitan areas including Nashville, TN (to the south) and Louisville, KY as well as to St. Louis, MO (northwest) and Indianapolis, IN (north).

Operating Risk

Big River's strong operating risk assessment reflects a consistently low operating cost burden of about 5 cents/KWh since at least 2014. Operating costs are anticipated to remain low as resource capacity is expected to remain sufficient to meet existing member and newly added customer load and capital needs are manageable. In addition, power is supplied mainly by low-cost vintage generating units and contracted purchases, all of which is further supported by access to the MISO market.

Operating Cost Flexibility

Fitch assesses Big River's operating cost flexibility as neutral as its past reliance on coal-fired generation has declined. The assessment takes into account the corporation's current resource base that includes four owned generating facilities (all coal) as well as contracted hydroelectric capacity. In 2019, approximately 78% of total capacity is coal-fired, followed by hydro capacity at 16% and a small amount of natural gas.

Big Rivers currently owns and operates 1,000 MWs of net generating capacity consisting of the following coal-fired facilities: Green generating station, a two-unit 454 MW facility that has the ability to burn high Sulphur, low cost coal; Wilson generating station, a 417 MW single unit facility; and the smallest of BR's generating assets - Reid Station (130 MW). In addition, Big Rivers also receives power through contract with Southeastern Power

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Administration (SEPA) for 178 MWs of hydroelectric capacity, bringing total current capacity to over 1,100 MWs. Big Rivers' 2017 decision to idle the 443 MW three-unit Coleman Station has helped improve its resource mix.

Not included in the assessment cost flexibility assessment is the capacity from the coal-fired plant owned by the city of Henderson, KY. Pursuant to a long-standing agreement with Henderson, Big Rivers received the surplus energy from the plant after Henderson's own retail needs were met, which had been roughly equivalent to 180MW-190MW per year. The Henderson plant was no longer capable of providing economical, continuous and reliable operation, leading both parties to agree to de-commission it in early 2019. The retirement of the Henderson plant, which was approved by regulators in late 2018, resulted in the elimination of a net operating loss on the asset of roughly $13 million annually.

Environmental Considerations

The Commonwealth of Kentucky does not currently have a renewable portfolio standard. However, Big Rivers issued a request for proposal to add up to 150 MWs of solar capacity. The expectation is to enter into a 20 year purchase power agreement at a fixed price. A short list of respondents and potential projects is currently being evaluated. The additional capacity is not expected to be available for at least several years. However, once available, capacity from coal resources will decline to around 70%.

Capital Planning and Management

Capital planning and management are assessed to be midrange. Big Rivers has an exceptionally high, Fitch-calculated average age of plant of 49 years in 2018, which indicates high life-cycle needs. This is somewhat offset by capital spending that has averaged 131% of annual depreciation over the past five years and an anticipated acceleration in annual depreciation expense and approval to treat several of its generating facilities as regulatory assets is received over the near term.

The regulatory asset designation will allow Big Rivers to include a larger proportion of the depreciation of these assets in its rating case with regulators for enhanced future cost recovery. Management anticipates capital spending for 2019-2023 to total a fairly sizeable $355 million, which continues a recent trend of sound capital reinvestment undertaken over the past few years. Roughly $250 million in additional debt is expected to be issued to fund the proposed capital spending.

Reduction in Long Generation Portfolio Position

Big Rivers historically provided capacity and energy to its members through a combination of multiple owned generation stations, including a leased facility (Henderson Station 2) and power purchases. After the loss of load attributable to the two large aluminum smelters, system peak demand declined to around 650 MWs, or roughly half of historical demand, leading to a very long resource position. To address this, Big Rivers implemented a mitigation plan with the goal of achieving financial savings and benefits that would help lower member rates. The plan included aggressively marketing the excess power under intermediate-term contracts and through spot sales in MISO.

More recently, growth in the existing customer base coupled with the signing of bi-lateral contracts with Kentucky Municipal Energy Agency (KyMEA, A/Stable), a consortium of Nebraska-based utilities, and full requirements sales to the city of Owensboro, KY (beginning in 2020) significantly increases contracted (non-member) sales and lowers reliance on short-term markets. In addition, the idling of the capacity at Coleman station and de-commissioning of the Henderson plant reduces total capacity to a manageable reserve of around 10% of total expected peak demand by 2020 (1,179 MW of capacity vs 1,026 MW of peak demand).

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Operations at the Coleman plant (443 MW) were initially idled in 2014. Coleman is expected to be retired in the near term.

The wholesale customers in Nebraska began receiving energy in 2018, but full requirements capacity and energy totaling 85 MWs will phase in over time. KYMEA's 100 MW of firm purchases began May 1, 2019 and is followed by the city of Owensboro's agreement to purchase full requirements (165 MW) from Big Rivers beginning in mid-2020. The inclusion of these intermediate term contracts brings some predictability to the revenue base, which coupled with the idling and retiring of certain generating assets right-sizes the total resource needs relative to member and contracted demand. Big Rivers is expected to add up to 150 MW of solar in the coming years, 100 MW of which will be used to meet the expected 200 MWs of new demand from Nucor Steel.

Financial Profile

Improved Financial Results

Big Rivers filed a rate case with the Kentucky Public Service Commission (KPSC) in 2013 requesting an increase in rates to levels that would provide full cost recovery of system obligations. The KPSC granted the new rates in 2014, but the full effect of the increases were not realized until fiscal 2017, as previously set aside reserves were used to keep member rates low over several years leading up to 2017.

Fitch-calculated debt service coverage improved to 1.30x in fiscal 2017 (and to 1.36x in 2018) from very weak levels previously, and coverage of full obligations improved to 1.28x by 2018. Audited fiscal year Sept. 30, 2019 results are not expected to be available for several months, but are anticipated to be sound once again. The improved performance over the past few years is largely attributable to the full implementation of the cooperative's risk mitigation strategy and approved rate plan.

However, the mitigation reserves have been fully utilized and Fitch believes the improved leverage ratios that have resulted from a steady decline in net debt and rise in funds available for debt service (FADS) over the past few years is likely to continue. Cash remains near historical norms and at 57 days cash on hand is considered neutral to the financial profile assessment. A $100 million senior secured credit agreement provides added liquidity.

Fitch Analytical Stress Test (FAST) Base and Rating Case Analysis

Fitch's base case is based on Big River's financial pro forma for fiscal years 2019 - 2023, which conservatively incorporates a slight decline in energy and revenues followed by limited growth through the forecast and annual spending for capital improvements totaling $356 million through 2023. The base case assumes $294 million of outstanding principal will be retired (including cash defeasances) although a portion of the capital plan will be funded with additional debt.

The Fitch base case aligns with Big Rivers' forecasted margins, which includes a decline in operating expenses related to the closure of Station 2 in 2019, and regulatory approval to treat station 2 as a regulatory asset, a rise in annual depreciation beginning in 2019, and an expected increase in sales related to Owensboro, KY and the expected opening of a new facility by Nucor Steel in 2022. The base case shows a decline in leverage in year one (2019) to 6.9x followed by a further modest decline in the leverage ratio throughout the remainder of the forward look.

For the rating case, the FAST incorporates a stress in sales in the first two years aggregating to 16% before a return to sales growth in years three through five. The previously mentioned base case assumptions are also

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applied. The result of the stress is an increase in the leverage ratio to 9.1x in year two before an expected return of sales growth and presumed rate increases that would allow the utility to maintain at least a minimal amount of cash in subsequent years. Fitch believes the above stress-induced leverage ratio would remain fully supportive of the current rating. However, if actual leverage declines as projected in the base case, a higher rating could be warranted.

Debt Profile

The debt profile is neutral to the rating. Big Rivers had approximately $760 million in total outstanding debt as of fiscal year-end 2018. All of the outstanding debt is fixed rate maturing no later than 2032 and includes a large bullet maturity of $245 million due in 2023. Management expects to cash-fund roughly half of this payment and refinance the rest with long-term, fully amortizing bonds.

In addition to the sources of information identified in Fitch's applicable criteria specified below, this action was informed by information from Lumesis.

ESG Considerations

Unless otherwise disclosed in this section, the highest level of ESG credit relevance is a score of 3 - ESG issues are credit neutral or have only a minimal credit impact on the entity, either due to their nature or the way in which they are being managed by the entity.

For more information on Fitch's ESG Relevance Scores, visit www.fitchratings.com/esg.

RATING ACTIONS

ENTITY/DEBT	RATING		PRIOR
Big Rivers Electric Corporation (KY)	LT IDR BBB- Affirmed		BBB-
Big Rivers Electric Corporation (KY) /Senior Secured Obligation/1 LT	LT BBB- Affirmed		BBB-

Additional information is available on www.fitchratings.com

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Applicable Criteria

U.S. Public Power Rating Criteria (pub. 03 Apr 2019)
Public Sector, Revenue-Supported Entities Rating Criteria (pub. 07 Nov 2019)

Additional Disclosures

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