Big Rivers
ELECTRIC CORPORATION

201 Third Street
P.O. Box 24
Henderson, KY 42419-0024
270-827-2561
www.bigrivers.com

RECEIVED
MAY 01 2018
PUBLIC SERVICE
COMMISSION

May 1, 2018

VIA HAND DELIVERY

Ms. Gwen R. Pinson
Executive Director
Public Service Commission
211 Sower Boulevard, P.O. Box 615
Frankfort, Kentucky 40602-0615

Re: *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

Dear Ms. Pinson:

Enclosed for filing on behalf of Big Rivers Electric Corporation are the following: (i) an original and ten copies of a Notice and Application, (ii) an original and ten copies of a petition for confidential treatment, (iii) one sealed copy the confidential information being filed pursuant to the petition for confidential treatment, and (iv) an original and ten copies of a motion for deviation. As noted in the Notice and Application, today Big Rivers is serving by hand delivery courtesy copies of the public version of these documents on the City of Henderson and on the Utility Commission of the City of Henderson, at the addresses shown on the attached service list.

Please feel free to contact me if you have any questions.

Sincerely,

TDK

Tyson Kamuf
Corporate Attorney, Big Rivers Electric Corporation

BIG RIVERS ELECTRIC CORPORATION

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

Service List

City of Henderson, Kentucky
222 First Street
Henderson, KY 42420
Attention: Mayor

Hon. Dawn Kelsey
City Attorney
City of Henderson, Kentucky
222 First Street
Henderson, KY 42420

Utility Commission of the City of Henderson, Kentucky
100 Fifth Street
Henderson, KY 42420
Attention: Chris Heimgartner

ORIGINAL

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

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

NOTICE and APPLICATION

with

DIRECT TESTIMONY

FILED: May 1, 2018

ORIGINAL

RECEIVED

MAY 01 2018

PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

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

PETITION FOR CONFIDENTIAL TREATMENT

1. Big Rivers Electric Corporation ("Big Rivers") hereby petitions the Kentucky Public Service Commission ("Commission"), pursuant to 807 KAR 5:001 Section 13 and KRS 61.878, to grant confidential protection to the confidential information in the Notice and Application and the exhibits thereto that Big Rivers is filing with this petition. The information Big Rivers seeks to protect as confidential consists of Big Rivers' financial model; production cost model information; projections of power market prices, coal and other fuel prices, emission allowance prices, other fixed and variable operation and maintenance ("O&M") costs, unit start-up and mill cycle costs, capital project costs, decommissioning costs, and rates; planned outage schedules and other information relating to projected unit generation and availability, including projected sales to members; recent energy and capacity revenues, which would give insight into projected revenue amounts; and information such as totals, margins, TIER, and cash balances that can be used in combination with other information to calculate the other Confidential Information. The information Big Rivers seeks to protect as confidential is hereinafter referred to as the "Confidential Information."

2. One (1) sealed copy of the paper pages containing Confidential Information, with the Confidential Information highlighted with transparent ink, printed on yellow paper, or

otherwise marked "CONFIDENTIAL," is being filed with this petition. Ten (10) copies of those pages with the Confidential Information redacted are also being filed with this petition. 807 KAR 5:001 Section 13(2)(a)(3).

3. As noted in the accompanying motion for deviation, except for two documents, Big Rivers is providing all of the documents from Exhibit Berry-2 in both electronic and paper formats. The other two documents are being provided in electronic format only. One (1) copy of all of the electronic files containing Confidential Information is contained on the confidential CD that accompanies this petition.

4. The two documents being provided only electronically consist of a long-term financial forecast file and a file with numerous assumptions and inputs relating to the financial forecast. These are key internal strategic planning documents, and as such, the entirety of these files is confidential. The Commission has consistently recognized that such internal strategic planning information and related materials are entitled to confidential treatment, as these documents typically relate to the company's economic status and business strategies. Information such as this which bears upon a company's detailed inner workings is generally recognized as confidential or proprietary. *See, e.g., Hoy v. Kentucky Indus. Revitalization Authority*, 907 S.W.2d 766, 768 (Ky. 1995) ("It does not take a degree in finance to recognize that such information concerning the inner workings of a corporation is 'generally recognized as confidential or proprietary'"). Additionally, the Commission has previously granted confidential treatment to similar information. *See, e.g., In the Matter of: Application of Big Rivers Electric Corporation for a General Adjustment in Rates*, Order, P.S.C. Case No. 2012-00535 (April 25, 2013) (granting confidential treatment to internal strategic documents such as valuation analyses and Board and committee meeting minutes); *In the Matter of: An Examination of the Application*

of the Fuel Adjustment Clause of East Kentucky Power Cooperative, Inc. From November 1, 2011 Through April 30, 2012, Order, P.S.C. Case No. 2012-00319 (February 21, 2013) (granting confidential treatment to internal strategic policies). Additionally, the information in the files is inextricably intertwined, and Big Rivers is unable to redact only some of the information from the electronic spreadsheet files without making other cells in the spreadsheets unusable or breaking the formulas contained therein. The accompanying motion for deviation seeks a deviation from the requirement that Big Rivers file paper confidential and redacted copies of those two electronic files.

5. There are no other parties who are entitled to be served with a copy of the petition or a copy of the redacted pages. 807 KAR 5:001 Section 13(2)(b)

6. If and to the extent the Confidential Information becomes generally available to the public, whether through filings required by other agencies or otherwise, Big Rivers will notify the Commission and have the information's confidential status removed. 807 KAR 5:001 Section 13(10)(b).

7. As discussed below, the Confidential Information is entitled to confidential protection based upon KRS 61.878(1)(c)(1), which protects "records confidentially disclosed to an agency or required by an agency to be disclosed to it, generally recognized as confidential or proprietary, which if openly disclosed would permit an unfair commercial advantage to competitors of the entity that disclosed the records." KRS 61.878(1)(c)(1); 807 KAR 5:001 Section 13(2)(a)(1).

I. Big Rivers Faces Actual Competition.

8. Big Rivers, as a participant in the credit markets and the wholesale power markets, faces economic competition from other entities.

9. Big Rivers competes in the wholesale power market to sell energy it produces in excess of its members' needs. Big Rivers' ability to successfully compete in the wholesale power market is dependent upon a combination of its ability to negotiate the maximum price for the power sold and its ability to keep its cost of production as low as possible. If Big Rivers' cost of producing a kilowatt-hour of energy increases, its ability to sell that kilowatt-hour in competition with other utilities is adversely affected.

10. Big Rivers also competes for reasonably priced credit in the credit markets, and its ability to compete is directly impacted by its financial results. Any event that adversely affects Big Rivers' margins will adversely affect its financial results and potentially impact the price it pays for credit. As was described in the proceeding before this Commission in the Big Rivers Unwind Transaction, Big Rivers expects to be in the credit markets on a regular basis in the future.[1]

11. As is evidenced by these economic pressures, Big Rivers faces actual competition from other market participants in the wholesale power and credit markets.

II. The Confidential Information is Generally Recognized as Confidential or Proprietary.

12. The Confidential Information for which Big Rivers seeks confidential treatment under KRS 61.878(1)(c)(1) is generally recognized as confidential or proprietary under Kentucky law.

13. Public disclosure of the Confidential Information would provide insight into Big Rivers' cost of producing power; Big Rivers' availability and need for power; the prices at which Big Rivers is willing to buy or sell power, fuel, emission allowances, and other items; and the

[1] *See In the Matter of: Joint Application of Big Rivers, E.ON, LG&E Energy Marketing, Inc., and Western Kentucky Energy Corporation for Approval to Unwind Lease and Power Purchase Transactions*, Order, P.S.C. Case No. 2007-00455 (March 6, 2009), pages 27-30 and 37-39.

amounts Big Rivers is willing to pay for capital projects. The information is also indicative of the market conditions Big Rivers expects to encounter and its ability to compete with competitors.

14. As noted above, information such as this which bears upon a company's detailed inner workings is generally recognized as confidential or proprietary. *See, e.g.*, *Hoy*, 907 S.W.2d at 768; *Marina Management Servs. v. Cabinet for Tourism, Dep't of Parks*, 906 S.W.2d 318, 319 (Ky. 1995) (unfair commercial advantage arises simply from "the ability to ascertain the economic status of the entities without the hurdles systemically associated with the acquisition of such information about privately owned organizations"). Moreover, the Commission previously granted confidential treatment to this type of information. *See, e.g.*, *In the Matter of: Application of Big Rivers Electric Corporation for a General Adjustment in Rates*, Order, P.S.C. Case No. 2012-00535 (April 25, 2013); *In the Matter of: Application of Big Rivers Electric Corporation for a General Adjustment in Rates*, Order, P.S.C. Case No. 2012-00535 (August 14, 2013); *In the Matter of: Application of Big Rivers Electric Corporation for Approval of its 2012 Environmental Compliance Plan, for Approval of its Amended Environmental Cost Recovery Surcharge Tariff, for Certificates of Public Convenience and Necessity, and for Authority to Establish a Regulatory Account*, Letter, P.S.C. Case No. 2012-00063 (August 15, 2012); P.S.C. Administrative Case No. 387, Letter (July 20, 2010).

15. The Confidential Information is not publicly available, is not disseminated within Big Rivers except to those employees and professionals with a legitimate business need to know and act upon the information, and is not disseminated to others without a legitimate need to know and act upon the information.

16. Accordingly, the information for which Big Rivers seeks confidential treatment is recognized as confidential or proprietary under Kentucky law and is entitled to confidential protection as further discussed below.

III. Disclosure of the Confidential Information Would Permit an Unfair Commercial Advantage to Big Rivers' Competitors.

17. Disclosure of the Confidential Information would permit an unfair commercial advantage to Big Rivers' competitors. As discussed above, Big Rivers faces actual competition in the wholesale power market and in the credit market. It is likely that Big Rivers would suffer competitive injury if that Confidential Information was publicly disclosed, and the information should therefore be subject to confidential treatment.

18. The Confidential Information includes material such as Big Rivers' projections of fuel and emissions costs and power prices, capital project costs, generation levels and availability, and other information revealing Big Rivers' costs of producing power. If that information is publicly disclosed, market participants would have insight into the prices at which Big Rivers is willing to buy and sell fuel, emissions, and power, and the amount Big Rivers is willing to pay for capital projects, and those market participants could manipulate the bidding process when selling to or buying from Big Rivers, increasing Big Rivers' costs or reducing its revenues. Increased costs would impair Big Rivers' ability to generate power at competitive rates and thus to compete in the wholesale power markets. Furthermore, any competitive pressure that adversely affects Big Rivers' revenue and margins could make the company appear less creditworthy and thus impair its ability to compete in the credit markets. These effects were recognized in P.S.C. Case No. 2003-00054, in which the Commission granted confidential treatment to bids submitted to Union Light, Heat & Power ("ULH&P"). ULH&P argued, and the Commission implicitly accepted, that if the bids it received were publicly disclosed,

contractors on future work could use the bids as a benchmark, which would likely lead to the submission of higher bids. *In the Matter of: Application of the Union Light, Heat and Power Company for Confidential Treatment*, Order, P.S.C. Case No. 2003-00054 (August 4, 2003). The Commission also implicitly accepted ULH&P's further argument that the higher bids would lessen ULH&P's ability to compete with other gas suppliers. *Id.* Similarly, potential fuel, allowance, and power suppliers and buyers manipulating Big Rivers' bidding process would lead to higher costs or lower revenues to Big Rivers and would place it at an unfair competitive disadvantage in the wholesale power market and credit markets.

19. Additionally, public disclosure of the Confidential Information would give the power producers and marketers with which Big Rivers competes in the wholesale power market insight into Big Rivers' cost of producing power and availability of power. Knowledge of this information would give those power producers and marketers an unfair competitive advantage because they could use that information to potentially underbid Big Rivers in wholesale transactions.

20. Thus, public disclosure of the Confidential Information would permit an unfair competitive advantage to Big Rivers' competitors.

IV. Time Period

21. Big Rivers requests that the Confidential Information remain confidential for a period of five years from the date of this petition, at which time the Confidential Information will be sufficiently outdated so that it could not be used to competitively disadvantage Big Rivers. 807 KAR 5:001 Section 13(2)(a)(2).

V. Conclusion

22. Based on the foregoing, the Confidential Information is entitled to confidential protection. If the Commission disagrees that Big Rivers is entitled to confidential protection, due process requires the Commission to hold an evidentiary hearing. *See Utility Regulatory Comm'n v. Kentucky Water Serv. Co., Inc.*, 642 S.W.2d 591 (Ky. App. 1982).

WHEREFORE, Big Rivers respectfully requests that the Commission classify and protect as confidential the Confidential Information.

On this the 1st day of May, 2018.

Respectfully submitted,

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Counsel for Big Rivers Electric Corporation

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MAY 01 2018

PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

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

NOTICE AND APPLICATION

Introduction

1. The Applicant, Big Rivers Electric Corporation ("Big Rivers"), is a rural electric cooperative corporation that generates, transmits, and sells electric power in the Commonwealth of Kentucky. Big Rivers is one of the contracting parties in a series of related contracts ("Station Two Contracts" or "Contracts") with the City of Henderson, Kentucky and the City of Henderson Utility Commission (collectively "Henderson"), which relate to the operation of an electric generating plant in Henderson, Kentucky commonly referred to in the Contracts as Station Two. Station Two is owned by Henderson and is maintained and operated by Big Rivers as an independent contractor under the Contracts.

2. As explained in more detail below, pursuant to Section 1 of the 1998 amendments to the Contracts (the "1998 Amendments"), the term of each of the Contracts, except for the Joint Facilities Agreement, expires when the Station Two units are no longer capable of normal, continuous, reliable operation for the economically competitive production of electricity. Big Rivers, as the operator of Station Two, has determined that the Station Two units are in fact no longer capable of normal, continuous, reliable operation for the economically competitive production of electricity. Accordingly, Big Rivers is delivering a notice to Henderson on May 1,

2018, informing Henderson that the Station Two Contracts, except for the Joint Facilities Agreement, have terminated. A copy of Big Rivers' notice of termination to Henderson is attached to this Notice and Application as Exhibit 1. As the Contracts are subject to the jurisdiction of the Public Service Commission ("Commission") under KRS 278.200, Big Rivers is providing notice of the termination of the Contracts that have terminated (the "Terminated Contracts") to the Commission through this Notice and Application.

3. Additionally, Henderson has indicated that it will dispute any attempt by Big Rivers to cease performance under the Contracts. Resolution of this dispute is also subject to the jurisdiction of the Commission. The Contracts provide that they "shall be subject to the approval of all local, state or federal regulatory bodies having jurisdiction thereof."[1] Furthermore, the Commission has previously exercised jurisdiction over the Contracts by approving the Contracts and amendments thereto, including amendments specifically relating to the termination provisions that are at issue in this proceeding, and by resolving other issues that have arisen between the parties arising out of the Contracts.[2]

4. Big Rivers respectfully requests, pursuant to KRS 278.200 and 807 KAR 5:001 Section 19, that the Commission exercise its jurisdiction to resolve the dispute between Big Rivers and Henderson by issuing a declaratory order confirming Big Rivers' determination that the Station Two units are no longer capable of normal, continuous, reliable operation for the economically competitive production of electricity and that the Terminated Contracts have terminated.

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[1] *See, e.g.*, Power Sales Contract § 25.1. The Power Sales Contract is one of the Contracts.

[2] *See* Order, P.S.C. Case No. 5406 (Oct. 22, 1970) (approving the Contracts); Order, P.S.C. Case No. 1998-00267 (July 14, 1998) (approving the 1998 Amendments to the Contracts); Order, P.S.C. Case No. 94-032 (March 31, 1995) (approving the 1993 amendments to the Contracts (the "1993 Amendments")); Order, P.S.C. Case No. 2016-00278 (Jan. 5, 2018).

5. Furthermore, Big Rivers requests an order from the Commission pursuant to KRS 278.200 authorizing Big Rivers to continue operating the Station Two units under the terms of the Contracts for up to 13 months to allow Henderson time to make alternate arrangements for the operation of Station Two and Henderson's power supply needs, if Henderson desires that Big Rivers do so.

6. Big Rivers further requests, pursuant to KRS 278.220, an order from the Commission authorizing Big Rivers to establish a regulatory asset to defer certain expenses Big Rivers will incur as a result of the termination of the Terminated Contracts.

7. Finally, Big Rivers requests that the Commission issue a final order in this matter on an expedited basis.

Background

8. As explained above, Big Rivers is a rural electric cooperative corporation organized pursuant to KRS Chapter 279. Its full name is Big Rivers Electric Corporation. Its mailing address is P.O. Box 24, Henderson, Kentucky 42419-0024. Its street address is 201 Third Street, Henderson, Kentucky 42420. Its address for electronic mail service is regulatory@bigrivers.com. 807 KAR 5:001 Section 14(1).

9. Big Rivers owns generating assets and purchases, transmits and sells electricity at wholesale. Its principal purpose is to provide the wholesale electricity requirements of its three distribution cooperative members: Jackson Purchase Energy Corporation, Kenergy Corp., and Meade County Rural Electric Cooperative Corporation (collectively, the "Members"). The Members in turn provide retail electric service to approximately 116,000 consumers/retail members located in 22 western Kentucky counties: Ballard, Breckenridge, Caldwell, Carlisle, Crittenden, Daviess, Graves, Grayson, Hancock, Hardin, Henderson, Hopkins, Livingston, Lyon, Marshall, McCracken, McLean, Meade, Muhlenberg, Ohio, Union, and Webster.

10. Big Rivers was incorporated in the Commonwealth of Kentucky on June 14, 1961, and hereby attests that it is currently in good standing in Kentucky. 807 KAR 5:001 Section 14(2).

11. The City of Henderson is a municipality in Western Kentucky with a street address of 222 First Street, Henderson, Kentucky 42420, and a mailing address of P.O. Box 716, Henderson, Kentucky 42419-0716. The City of Henderson Utility Commission, d/b/a Henderson Municipal Power and Light, is a municipal utility organized under the law of Kentucky with an address of 100 Fifth Street, Henderson, Kentucky 42420.

12. Big Rivers is serving a copy of this Notice and Application on the Mayor of the City of Henderson, the City of Henderson Utility Commission, and the city attorney for the City of Henderson, by hand delivery on May 1, 2018.

Request for Commission Findings

13. As explained earlier in this Notice and Application, Big Rivers, as the Station Two operator, has determined that the Station Two units are no longer capable of normal, continuous, reliable operation for the economically competitive production of electricity. However, because Henderson has informed Big Rivers that it will "push back" on any attempt by Big Rivers to cease performance under the Contracts, Big Rivers requests a finding from the Commission supporting Big Rivers' determination that the Station Two units are no longer capable of normal, continuous, reliable operation for the economically competitive production of electricity and that as a result, the Terminated Contracts have terminated pursuant to the terms of the 1993 Amendments and the 1998 Amendments. Big Rivers also requests a finding from the Commission authorizing Big Rivers to continue to operate Station Two under the terms of the Contracts to allow Henderson time to make alternate arrangements for the operation of Station Two and for Henderson's power supply needs, if Henderson desires that Big Rivers do so.

14. The 1993 Amendments gave Big Rivers the option to extend the term of the Contracts "to continue for so long as [either of the Station Two units] is operated, or is capable of normal, continuous, reliable operation for the economically competitive production of electricity, temporary outages excepted."[3] Big Rivers exercised that option, and when the 1998 Amendments were approved by the parties, they incorporated into the Contracts a provision stating that termination should occur when Station Two is no longer capable of normal, continuous, reliable operation for the economically competitive production of electricity. Section 1 of the 1998 Amendments provides:

> The terms of all [of the Station Two Contracts] except the Joint Facilities Agreement shall be extended for the operating life of Station Two, the operating life of which shall be considered to continue for so long as Unit 1 and Unit 2, or either of them, is operated, or is capable of normal, continuous, reliable operation for the economically competitive production of electricity, temporary outages excepted.

15. The 1993 Amendments and 1998 Amendments are attached to this Notice and Application as Exhibits 2 and 3, respectively. Pursuant to 807 KAR 5:001 Section 11(5), Big Rivers moves the Commission for an order making the other principal Contracts, which were filed as Exhibits 1-5 and 8 to Big Rivers' application in P.S.C. Case No. 2016-00278, part of the record in this case by reference only.[4]

16. As explained in more detail in the Direct Testimony of Robert W. Berry and the Direct Testimony of Metin Celebi, which are attached hereto as Exhibits 4 and 5, respectively, the Station Two units are no longer capable of normal, continuous, reliable operation for the

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[3] 1993 Amendments § 1.1.

[4] *In the Matter of: The Application of Big Rivers Electric Corporation for a Declaratory Order.* As noted in the notice of termination Big Rivers is sending to Henderson, there are a number of stand alone agreements between Big Rivers and Henderson that are not part of the Contracts and that are not terminated pursuant to Section 1 of the 1998 Amendments.

economically competitive production of electricity, and as such, all of the Station Two Contracts, except the Joint Facilities Agreement, as amended, have terminated.

17. Mr. Berry describes in his testimony that Henderson has said that it will "push back" on any attempt by Big Rivers to exit the Contracts. The Commission has approved the Contracts and the amendments thereto, including the termination provision in Section 1 of the 1998 Amendments. Although that termination provision requires no prior authorization from the Commission, Big Rivers requests that the Commission enter an order pursuant to KRS 278.200 and 807 KAR 5:001 Section 19 resolving the dispute between Big Rivers and Henderson by finding that (1) the Station Two units are no longer capable of normal, continuous, reliable operation for the economically competitive production of electricity, and (2) as a result, the Terminated Contracts terminated as of May 1, 2018.

18. Additionally, there is no notice provision in Section 1 of the 1998 Amendments that would allow Henderson time to make alternate arrangements for the operation of Station Two and for Henderson's power needs; however, Big Rivers is willing to continue to operate the Station Two units under the terms of the Contracts until May 31, 2019, unless Big Rivers and the City reach a mutually acceptable agreement regarding the ongoing operation of Station Two prior to that date, or Big Rivers is ordered to cease operation of Station Two by the Commission prior to that time. Accordingly, Big Rivers requests a finding from the Commission pursuant to KRS 278.200 authorizing Big Rivers to continue to operate Station Two under the terms of the Contracts for a period up to and including May 31, 2019, if Henderson desires that Big Rivers do so.

Request for Authority to Establish a Regulatory Asset

19. Big Rivers currently has on its books an approximately $89.6 million asset relating to the value of the Contracts that Big Rivers will have to retire and write off as a result of

the termination of the Terminated Contracts. Absent approval from the Commission for Big Rivers to establish a regulatory asset to defer its expenses relating to the termination of the Terminated Contracts, this write-off will result in Big Rivers having to recognize a one-time expense of $89.6 million, but it will have no ability to recover that expense through its rates. Big Rivers will also incur other expenses relating to the termination of the Terminated Contracts, including but not limited to the costs of consultants and the costs of prosecuting this case.

20. The expenses Big Rivers will incur as a result of the termination of the Terminated Contracts are not currently included in its rates, but Big Rivers believes that those expenses should be recoverable through rates in the future because the termination of the Terminated Contracts will result in substantial savings to Big Rivers. As discussed in the Direct Testimony of Robert W. Berry, the improvement to Big Rivers' net margins resulting from the termination of the Terminated Contracts is estimated at approximately $[redacted] over the period covered by Big Rivers' long-term financial plan.

21. To defer the expenses it will incur as a result of the termination of the Terminated Contracts, Big Rivers needs the approval of both the Rural Utilities Service ("RUS") and the Commission to establish a regulatory asset. Big Rivers has sought and obtained approval from RUS to establish such a regulatory asset. RUS' letters stating that it has no objection to the contract termination and authorizing Big Rivers to establish a regulatory account relating to the contract termination are attached hereto as Exhibit 6. Big Rivers requests that the Commission likewise authorize Big Rivers to defer these expenses in a regulatory asset.

22. Although the expenses resulting from the contract termination are not included in Big Rivers' rates, Big Rivers does recover through its rates an amount for depreciation expense

relating to Station Two. Big Rivers will offset the revenues it receives associated with Station Two depreciation expense against the regulatory asset described above.

23. The authority of the Commission to allow utilities to establish regulatory assets "arises under the Commission's plenary authority to regulate utilities under KRS 278.040 and the Commission's authority to establish a system of accounts under KRS 278.220."[5]

24. The Commission has previously authorized jurisdictional utilities to establish regulatory assets under certain circumstances, as the Commission has explained:

> Historically, the Commission has exercised its discretion to approve regulatory assets where a utility has incurred: (1) an extraordinary, nonrecurring expense which could not have reasonably been anticipated or included in the utility's planning; (2) an expense resulting from a statutory or administrative directive; (3) an expense in relation to an industry sponsored initiative; or (4) an extraordinary or nonrecurring expense that over time will result in a saving that fully offsets the cost.[6]

25. Since the expenses resulting from the termination of the Terminated Contracts that Big Rivers is seeking to defer are extraordinary and nonrecurring, and since the termination of the Terminated Contracts will result in substantial savings to Big Rivers that fully offsets the costs, Big Rivers requests that the Commission allow Big Rivers to establish a regulatory asset to defer those expenses. Big Rivers would then seek recovery of the amount recorded in the regulatory asset in its next base rate case, amortized over an appropriate period of time.

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[5] *In the Matter of: The Application of East Kentucky Power Cooperative, Inc. for an Order Approving Accounting Practices to Establish a Regulatory Asset related to Certain Replacement Power Costs Resulting from Generation Forced Outages*, Order, P.S.C. Case No. 2008-00436 (Dec. 23, 2008), at p. 4.

[6] *Id.; see also In the Matter of: Application of Louisville Gas and Electric Company for an Order Approving the Establishment of a Regulatory Asset*, Order, P.S.C. Case No. 2008-00456 (De. 22, 2008); *In the Matter of: Joint Application of Duke Energy Kentucky, Inc., Kentucky Power Company, Kentucky Utilities Company and Louisville Gas and Electric Company for an Order Approving Accounting Practices to Establish Regulatory Assets and Liabilities Related to Certain Payments Made to the Carbon Management Research Group and the Kentucky Consortium for Carbon Storage*, Order, P.S.C. Case No. 2008-00308 (Oct. 30, 2008).

Request for Expedited Ruling

26. Big Rivers requests that the Commission issue an expedited final ruling in this matter to give Henderson adequate time to make alternate arrangements for Station Two and its power supply needs prior to May 31, 2019, and in any event no later than August 31, 2018. To facilitate the Commission's consideration of this Notice and Application on an expedited basis, Big Rivers has included workpapers utilized in the analyses of the economic viability of Station Two with the attached testimony, and Big Rivers will submit to the Commission not later than May 7, 2018, any other applicable workpapers prepared or considered by Big Rivers and any witnesses who will testify on its behalf in this matter in support of this Notice and Application. Except as noted in the accompanying Motion for Deviation, the workpapers are being provided in both paper and electronic formats.

WHEREFORE, Big Rivers respectfully requests that the Commission enter an order:

1. granting the relief requested by Big Rivers above; and
2. granting all other relief to which Big Rivers may otherwise be entitled.

On this the 1st day of May, 2018.

Respectfully submitted,

Laura Chambliss
Tyson Kamuf
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Counsel for Big Rivers Electric Corporation

BIG RIVERS ELECTRIC CORPORATION

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. 2018-00_____

VERIFICATION

I, Robert W. (Bob) Berry, President and Chief Executive Officer of Big Rivers Electric Corporation, verify, state, and affirm that I have read the foregoing Notice and Application and that the statements contained therein are true and accurate to the best of my knowledge, information, and belief.

Robert W Berry

Robert W. (Bob) Berry

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Robert W. (Bob) Berry on this the 30 th day of April, 2018.

Paula Mitchell

Notary Public, Kentucky At Large

My Commission Expires 1-12-21

Big Rivers
ELECTRIC CORPORATION

201 Third Street
P.O. Box 24
Henderson, KY 42419-0024
270-827-2561
www.bigrivers.com

VIA HAND-DELIVERY AND
CERTIFIED MAIL (The Certified Mail copy does not include the Application)

May 1, 2018

Mr. Chris Heimgartner
General Manager
Henderson Municipal Power & Light
P.O. Box 8
Henderson, KY 42419

Re: Notice of Termination of Station Two Contracts

Dear Chris,

As you know, since 1970 Big Rivers Electric Corporation ("Big Rivers") has operated and maintained the City of Henderson's Station Two Power Plant under a series of contracts and related agreements, many of which were originally executed on August 1, 1970 (the "Station Two Contracts") and which have since been amended on several occasions. Section 1 of the 1998 amendments to the Station Two Contracts is currently operative, and provides:

> The terms of all [of the Station Two Contracts] except the Joint Facilities Agreement shall be extended for the operating life of Station Two, the operating life of which shall be considered to continue for so long as Unit 1 and Unit 2, or either of them, is operated, or is capable of normal, continuous, reliable operation for the economically competitive production of electricity, temporary outages excepted.

As you and I have discussed on various occasions over the last eighteen (18) months, Station Two has not been generating economically competitive electricity. Because of this, Big Rivers engaged a third-party firm to perform an analysis of whether Station Two (or either unit individually) is capable of normal, continuous, reliable operation for the economically competitive production of electricity. The study has been completed and confirms the units are no longer capable of generating economically competitive electricity. Therefore, by their own terms, the Station Two Contracts have terminated, with the exception of the Joint Facilities Agreement. Because the Station Two Contracts were originally approved by and are subject to the jurisdiction of the Kentucky Public Service Commission ("PSC"), Big Rivers has filed a Notice of Termination of Contracts and Application of Big Rivers Electric Corporation for a Declaratory Order and For Authority to Establish a Regulatory Asset with the PSC on May 1, 2018. A copy of that Notice and Application is being provided to you along with this letter. The PSC's regulations require that a response, if any, to an application for a declaratory order be filed with the PSC within 21 days after the date on which the application is filed.

While the Station Two Contracts do not require Big Rivers to provide the City with advance notice of termination of the contracts, as a courtesy, Big Rivers is willing to work with the City in the event it

Big Rivers Electric Corporation
Labor Impact of HMPL Split
Case No. 2018-00______

	2016	**2017**	**2018**	**2019**
Gross Labor	20,552,403	21,024,890	21,634,999	22,193,119
Net Labor	19,702,311	20,118,622	20,686,585	21,220,845
	850,092	906,268	948,414	972,274

*Labor includes capitalized labor and doesn't include reduction for churn

HMPL G&A Agreement (Base Case)	625,639
Impact to Big Rivers Margins Fav/(UnFav)	(322,775)

Big Rivers Electric Corporation
Station Two Estimated Net Book Value
Case No. 2018-00______

Station II Assets
Net Book Value
As of 12/31/2018 [1]

Category [2]	Description	Plant In-Service Account	Gross Book Value	Accumulated Depreciation [3]	Net Book Value
HMPL	STRUCTURES-HMPL	10103115	548,133.00	(67,892.58)	480,240.42
HMPL SHARE	STRUCTURES-R/HMPL	10103116	590,653.72	(79,125.72)	511,528.00
HMPL SHARE	STRUCTURES-R/G/HMPL	10103117	300,812.76	(100,126.63)	200,686.13
HMPL	BOILER PLANT EQUIPMNT	10103125	25,252,845.00	659,958.58	25,912,803.58
HMPL	ENVIRONMTL COMPLIANCE	1010312F	32,014,564.00	(7,381,996.85)	24,632,567.15
HMPL SHARE	ENVIRON COMPL-R/HMPL	1010312G	1,520,081.28	(305,696.40)	1,214,384.88
HMPL SHARE	BOILERPLANT,EC,HMPL/GREEN	1010312J	4,503.26	(2,086.63)	2,416.63
HMPL	SCRUBBER	1010312K	37,811,155.00	(19,204,101.69)	18,607,053.31
HMPL	ENVIRONMTL COMPL-SHORT LIFE	1010312Q	6,145,688.00	(6,171,648.44)	(25,960.44)
HMPL SHARE	BOILER PLANT-SHORT LIFE-R/HMPL	1010312U	148,912.75	(36,024.89)	112,887.86
HMPL	BOILER PLANT-SHORT LIFE	1010312Z	980,100.00	(99,279.13)	880,820.87
HMPL SHARE	BOILER PLANT-R/HMPL	10103126	2,506,547.39	(78,720.07)	2,427,827.32
HMPL SHARE	BOILER PLANT-R/G/HMPL	10103127	137,687.34	(31,801.84)	105,885.50
HMPL	TURBOGENERATOR UNITS	10103145	8,991,467.00	(1,241,623.37)	7,749,843.63
HMPL SHARE	TURBINE PLT-R/HMPL	10103146	890,470.28	12,237.53	902,707.81
HMPL SHARE	TURBINE PLT-R/G/HMPL	10103147	8,303.56	(3,533.38)	4,770.18
HMPL	ACCESS ELECTRIC EQUIP	10103155	4,462,079.00	1,444,706.16	5,906,785.16
HMPL SHARE	ACCESS ELECTRIC EQUIPMENT	10103157	15,228.84	(2,073.17)	13,155.67
HMPL	MISC POWER PLANT EQUIP	10103165	454,968.00	(100,094.63)	354,873.37
HMPL SHARE	COMMON PLANT-R/HMPL	10103166	803,896.15	(110,087.99)	693,808.16
HMPL SHARE	COMMON PLANT-R/G/HMPL	10103167	52,151.92	(14,527.06)	37,624.86
HMPL SHARE	OFFICE FURN & EQUIP-R/HMPL	10103916	5,757.21	(4,753.43)	1,003.78
HMPL SHARE	OFFICE FURN & EQUIP-R/G/HMPL	10103917	7,580.64	(6,326.27)	1,254.37
HMPL SHARE	MISC EQUIP-R/HMPL	10103986	-	-	-
HMPL SHARE	MISC EQUIP-R/G/HMPL	10103987	430.46	(290.96)	139.50
TOTAL			**123,654,016.56**	**(32,924,908.86)**	**90,729,107.70**

[1] Account Balances as of 12/31/2018 are estimated figures from the 2016-2019 Depreciation Budget.

[2] HMPL SHARE categories include accounts in which assets are shared between the Sebree Station plants. The Station II split allocation can be found on the 'Splits' worksheet.

[3] Accumulated Depreciation includes the Accumulated Depreciation on active assets ('Account Balances' Column D) and Gain/Loss amounts on retired assets in the Depreciation Reserve accounts ('Account Balances' Column E).

Big Rivers Electric Corporation
Statin Two Estimated Net Book Value
Case No. 2018-00______

Estimated Account Balances
2016-2019 Depreciation Budget
As of 12.31.2018

Plant in Service

Account	Gross Book Value	Accum Depr	Depr Reserve
10103010	420.00	-	-
10103020	66,476.00	-	-
10103101	83,342.00	-	-
10103102	1,124,665.00	-	-
10103103	1,110,712.00	-	-
10103104	2,218,858.00	-	-
10103111	3,272,657.00	(3,403,735.46)	130,210.09
10103112	19,771,615.00	(18,552,474.21)	387,149.33
10103113	27,404,354.00	(22,821,117.09)	716,110.65
10103114	75,499,371.00	(48,315,075.70)	1,526,081.13
10103115	548,133.00	(127,978.51)	60,085.93
10103116	795,922.00	(177,366.02)	70,741.95
10103117	1,135,571.00	(429,164.14)	51,185.16
10103119	853,947.00	(518,240.46)	48,656.82
10103120	166,704.00	(24,242.92)	10,082.98
10103121	7,703,496.00	(7,196,552.73)	1,077,977.86
10103122	82,506,522.00	(50,030,594.94)	7,614,553.64
10103123	183,700,886.00	(133,782,481.76)	12,005,511.98
10103124	416,940,738.00	(274,893,883.04)	27,213,265.08
10103125	25,252,845.00	(5,331,620.13)	5,991,578.71
10103126	3,377,641.00	(731,407.36)	625,329.92
10103127	519,771.00	(164,914.24)	44,862.00
1010312A	1,114,989.00	(141,821.16)	246,284.39
1010312B	5,069,516.00	(2,838,605.26)	114,664.33
1010312C	122,674,114.00	(34,545,314.00)	4,062,030.05
1010312D	131,458,394.00	(81,400,832.51)	17,011,513.12
1010312E	265,640,648.00	(172,150,696.78)	23,936,929.42
1010312F	32,014,564.00	(10,277,701.84)	2,895,704.99
1010312G	2,048,351.00	(478,453.14)	66,518.91
1010312J	15,438.00	(7,153.34)	-
1010312K	37,811,155.00	(20,054,292.91)	850,191.22
1010312N	1,104,354.00	(1,135,853.66)	161,178.00
1010312P	7,500,875.00	(8,238,057.48)	2,978,537.18
1010312Q	6,145,688.00	(6,734,747.45)	563,099.01
1010312U	200,664.00	(140,675.53)	92,131.00
1010312V	23,762.00	(37,182.16)	22,670.75
1010312W	412,629.00	(585,740.70)	169,176.46
1010312X	1,665,592.00	(1,349,545.79)	807,738.36
1010312Y	899,003.00	(765,673.22)	290,018.00

Big Rivers Electric Corporation
Statin Two Estimated Net Book Value
Case No. 2018-00______

Estimated Account Balances
2016-2019 Depreciation Budget
As of 12.31.2018

Plant in Service

Account	Gross Book Value	Accum Depr	Depr Reserve
1010312Z	980,100.00	(797,208.32)	697,929.19
10103141	4,066,364.00	(4,337,735.24)	385,928.55
10103142	33,795,866.00	(24,326,942.07)	2,320,329.61
10103143	62,983,645.00	(47,972,378.37)	3,866,126.07
10103144	129,376,894.00	(86,523,565.92)	3,263,707.24
10103145	8,991,467.00	(2,594,617.42)	1,352,994.05
10103146	1,199,933.00	(141,893.49)	158,383.90
10103147	31,346.00	(13,424.59)	86.02
10103151	1,701,148.00	(1,261,954.61)	160,029.73
10103152	9,440,861.00	(6,907,613.42)	216,566.60
10103153	18,512,350.00	(14,401,650.67)	823,436.35
10103154	35,817,460.00	(23,775,874.29)	641,270.05
10103155	4,462,079.00	(329,945.70)	1,774,651.86
10103156	37,556.00	(2,255.28)	22,561.00
10103157	57,489.00	(7,826.25)	-
10103159	43,548.00	(36,421.00)	17,753.16
10103160	143,212.00	(40,350.77)	-
10103161	15,854.00	(2,746.97)	-
10103162	1,344,809.00	(408,811.70)	15,861.64
10103163	1,578,730.00	(432,263.66)	119,996.60
10103164	1,583,280.00	(428,181.64)	353,256.52
10103165	454,968.00	(132,014.63)	31,920.00
10103166	1,083,272.00	(228,650.07)	80,303.50
10103167	196,874.00	(54,839.79)	-
10103169	750,845.00	(143,360.78)	230,156.00
10103410	193,561.00	(137,005.85)	18,900.79
10103420	1,446,805.00	(1,522,537.45)	65,744.49
10103430	6,351,497.00	(4,782,753.28)	173,752.94
10103440	1,188,518.00	(1,049,785.57)	31,393.64
10103450	633,795.00	(269,132.25)	112,040.77
10103500	14,548,691.00	-	-
10103501	704,868.00	-	-
10103520	6,385,859.00	(4,259,786.18)	151,234.91
10103521	54,739.00	(23,914.82)	2,038.61
10103522	157,305.00	(156,093.65)	(1,378.31)
10103524	698,103.00	(465,564.45)	5,409.34
10103530	111,482,221.00	(53,690,581.38)	11,941,682.64
10103531	3,194,085.00	(2,559,457.50)	299,446.40
10103532	5,627,588.00	(5,255,220.43)	283,146.03

Big Rivers Electric Corporation
Statin Two Estimated Net Book Value
Case No. 2018-00______

Estimated Account Balances
2016-2019 Depreciation Budget
As of 12.31.2018

Plant in Service

Account	Gross Book Value	Accum Depr	Depr Reserve
10103533	5,997,630.00	(5,722,587.18)	2.38
10103534	22,082,380.00	(16,855,735.68)	239,935.40
10103540	8,134,239.00	(5,793,106.74)	(35,730.51)
10103541	146,747.00	(132,776.06)	-
10103550	48,989,285.00	(30,313,595.40)	-
10103551	234,314.00	(240,620.56)	7.90
10103560	57,941,545.00	(30,771,203.17)	-
10103561	86,901.00	(88,896.59)	24.83
10103890	407,251.00	-	-
10103900	5,816,126.00	(3,723,395.08)	751,069.54
10103910	1,130,303.00	(1,005,542.61)	630,911.53
10103912	29,118,776.00	(18,568,394.13)	1,572,279.05
10103916	7,758.00	(6,405.38)	-
10103917	28,617.00	(23,881.74)	-
10103922	3,066,084.00	(1,704,566.69)	(260,556.12)
10103923	1,686,867.00	(1,616,193.05)	210,681.41
10103930	111,491.00	(109,330.89)	2,580.03
10103940	957,430.00	(761,652.92)	17,910.88
10103950	311,920.00	(259,277.13)	(10,559.85)
10103960	1,029,102.00	(292,443.76)	(25,104.49)
10103961	788,773.00	(234,598.87)	(77,004.68)
10103970	10,620,545.00	(4,192,082.66)	(37,090.12)
10103980	378,511.00	(268,115.28)	59,872.18
10103987	1,625.00	(1,098.38)	-
10113525	185,107.00	(36,672.24)	-
10113535	6,511,341.00	(1,553,489.30)	-
10113545	312,558.00	(55,444.03)	-
10113555	79,207.00	(20,424.58)	-
10113565	104,571.00	(22,181.93)	-
10503401	475,968.00	-	-
10103913	-	-	(74,758.64)
TOTAL	**2,147,914,939.00**	**(1,321,231,267.13)**	**144,422,899.03**

Big Rivers Electric Corporation
Station Two Estimated Net Book Value
Case No. 2018-00______

Station II Allocation Splits[1]

1 Reid/Station Two split @ 12/31/17:

Plant	MW	%
Reid	65	0.2579
Station II	187	0.7421
Total	**252**	**1.0000**

2 Reid/Station Two/Green split @ 12/31/17:

Plant	MW	%
Reid	65	0.0921
Station II	187	0.2649
Green	454	0.6431
Total	**706**	**1.0001**

3 Green/Station Two split @ 12/31/17:

Plant	MW	%
Green	454	0.7083
Station II	187	0.2917
Total	**641**	**1.0000**

1

Station II megawatt split is based on HMPL Capacity Letter dated March 24, 2015, utilizing the "Allocated to BREC" amount for June 1, 2018-May 31, 2019.

decides to make alternate arrangements regarding the operation of Station Two. As such, please allow this letter to also serve as notice of Big Rivers' offer to continue to operate and maintain Station Two under the same terms and conditions set forth in the Station Two Contracts until May 31, 2019, unless Big Rivers and the City reach a mutually acceptable agreement regarding the ongoing operation of Station Two prior to that date, or Big Rivers is ordered to cease operation of Station Two by the PSC prior to that time. Please let me know at your earliest convenience, and in any event no later than June 15, 2018, whether the City would like for Big Rivers to continue to operate and maintain Station Two for that time period, under those terms and conditions. To be clear, though, under no circumstances is Big Rivers willing to operate and maintain Station Two beyond May 31, 2019 absent a finding by the Kentucky Public Service Commission that requires it to do so. As noted above, the Joint Facilities Agreement will terminate in accordance with Section 8.1 of that Agreement. In addition to the Joint Facilities Agreement, as amended, there are various transmission and property related agreements that are standalone agreements that will remain in force following May 31, 2019. Those agreements are listed in Exhibit A.

Big Rivers remains committed to working with HMP&L in order to facilitate an orderly transition of operation and maintenance responsibilities to the City. To this end, I am providing to you an initial list of responsibilities that have been identified that will need to be transferred to the City on or before May 31, 2019 so that the City is in a position to take over the operation and maintenance of Station Two on or before June 1, 2019. This list is attached to this letter as Exhibit B. This list is not comprehensive and will in all likelihood need to be supplemented by the Parties as a result of ongoing discussions between HMP&L and Big Rivers over the next thirteen (13) months.

After you have had a chance to review this information, please contact me at your earliest convenience so that we may schedule a time to meet to begin working through these issues in an orderly and timely manner. I look forward to hearing from you soon.

Respectfully,

Robert W Berry

Robert W. Berry
President and CEO
Big Rivers Electric Corporation

Enclosures

May 1, 2018

EXHIBIT A

HMPL Contracts and Amendments to remain in effect post 5/31/19

Agreement for Transmission and Transformation Capacity dated April 11, 1975 between City of Henderson Utility Commission and Big Rivers Electric Corporation and

Switchyard Agreement (Reid Switchyard) dated June 1, 1978 between City of Henderson and Big Rivers Electric Corporation and amendments thereto

Interconnection Agreement dated April 1, 1968, and amendments thereto (including 10/31/81 and 1/10/89 amendments)

Transmission and Transformation Facilities Agreement dated July 1, 1999

Grant of Rights and of Easement dated April 1, 2005

Cross-Grants of Rights of Access and of Easements dated July 20, 1993

Deed of Easement [for Gas Line to Serve Reid Peaker Turbine] dated August 12, 2003

This list is not intended to be comprehensive

EXHIBIT B

TRANSFER OF RESPONSIBILITIES

1. HMPL's plans to operate or decommission Station Two following 5/31/19

2. HMPL's Registration of Station Two within MISO post 5/31/19 and impact, if any, to grandfathered agreements

3. HMPL's plans regarding waste disposal post 5/31/19

4. HMPL's designated representatives regarding emission allowances post 5/31/19

5. HMPL's plans to obtain environmental permits to operate Station Two post 5/31/19

6. Transfer of Energy Scheduling/Dispatch responsibilities to HMPL post 5/31/19

7. Transition of NERC Compliance Responsibilities related to Station Two to HMPL, including GADS reporting and NERC registrations/notifications, post 5/31/19

8. Spare Transformer maintenance and storage responsibilities post 5/31/19

9. Staffing of Station Two by HMPL following 5/31/19

10. HMPL's plans to insure Station Two post 5/31/19

11. HMPL's plans to obtain necessary software licenses and technology related services post 5/31/19

12. Coordinated development and execution of a joint work plan by Big Rivers and HMPL to facilitate an orderly transition of Station Two responsibilities to HMPL or its designee

13. HMPL's plans related to storage and delivery of coal, reagent, fuel oil, and ammonia post 5/31/19

14. Transfer of records to HMPL, including Plant System Drawings, OPLs, emergency response plans, etc.

15. Current Station Two Outage Plans and associated lead times

16. Transfer of routine maintenance responsibilities for Station Two to HMPL post 5/31/19

17. HMPL's need to continue utilizing Station Two Joint Facilities post 5/31/19

18. HMPL's plans, if any, to assume outstanding contracts related to the operation of Station Two post 5/31/19

19. HMPL's plans related to Station Two Inventory post 5/31/19

HOLBROOK, WIBLE, SULLIVAN & MOUNTJOY, P.S.C.

ATTORNEYS AT LAW

100 ST. ANN BUILDING

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TIMOTHY O. SHELBURNE
R. MICHAEL SULLIVAN

AREA CODE: 502
TELEPHONE NUMBER: 926-4000
TELECOPIER: 683-[illegible]

September 11, 1993

SEP 13 1993
BIG RIVERS
ELECTRIC CORPORATION

Richard M. Lawrence, Esq.
Office of the General Counsel
United States Department of Agriculture
Electric & Telephone Division
Room 2349, South Building
14th & Independence Avenue, S.W.
Washington, DC 20250-1400

Re: Recording of Cross-Grants of Rights of Access and of Easements dated July 20, 1993 among the City of Henderson, City of Henderson Utility Commission and Big Rivers Electric Corporation and of the Subordination Agreement dated August 26, 1993 among the REA, Chemical Bank, The Bank of New York as Mortgagees and City of Henderson, Kentucky, City of Henderson Utility Commission and Big Rivers Electric Corporation

Dear Richard:

I enclose a copy of each of the above-titled documents which were recorded in the office of Wilma G. Martin, Clerk of Henderson County, Kentucky, on September 9, 1993 at 1:00 o'clock p.m. CDT, the Cross-Grant in Book 433, Pages 198 through 209, and the Subordination Agreement in Mortgage Book 441 at Pages 690 through 700.

I have attached to the enclosed copy of the Cross-Grant of Easements the Approval Sheet executed by James B. Huff, Sr., on 9/7/93, and I have attached to the copy of the Subordination Agreement a copy of the Clerk's Certificate of Recording. Thus, the effective date of the Cross-Grant of Easements, as described in Paragraph 7, of that document, is September 9, 1993.

Sincerely yours,

Morton Holbrook

Morton Holbrook

MH/dfc

cc: Paul H. Keck, Esq. (w. enc.)
Barton D. Ford, Esq. (w. enc.)
Jeremiah L. Thomas III, Esq. (w. enc.)
Paul A. Schmitz (w. enc.)

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AGREEMENT, dated August 26, 1993, among the UNITED STATES OF AMERICA, acting by and through the Administrator of the RURAL ELECTRIFICATION ADMINISTRATION (Hereinafter being referred to as the "Government"), Chemical Bank, a New York banking corporation, and The Bank of New York, a New York banking corporation (Hereinafter being collectively referred to as the "Banks"), (The Government and the Banks being hereinafter collectively referred to as the "Mortgagees"), the CITY OF HENDERSON, KENTUCKY, A MUNICIPAL CORPORATION and city of the third class organized under the laws of Kentucky, City of Henderson Utility Commission, a public body corporate and politic organized under Kentucky revised statutes 96.520 and related statutes (Such City and Commission being hereinafter collectively referred to as the "City"), and BIG RIVERS ELECTRIC CORPORATION, a rural electric cooperative corporation organized under chapter 279 of the Kentucky Revised Statutes (Hereinafter being referred to as "Big Rivers").

W I T N E S S E T H:

WHEREAS, Big Rivers and the City are parties to a Power Sales Contract (Hereinafter being referred to as the "Power Sales Contract"), a Power Plant Construction and Operation Agreement and a Joint Facilities Agreement all dated August 1, 1970, an Agreement for Transmission and Transformation Capacity dated April 11, 1975, the Spare Transformer Agreement dated July 11, 1972, the System Reserves Agreement dated January 1, 1974, the Agreement dated April 8, 1980 regarding O&M and R&R Funds, the Agreement of February 15, 1991 concerning Administrative and General Costs, and the Amendments to Contracts Among City of Henderson, Kentucky, City of Henderson Utility Commission and Big Rivers Electric Corporation dated for convenience as of May 1, 1993 but executed in fact on June 29, 1993 (Hereinafter being referred to as the "1993 Amendments") and filed with the Kentucky Public Service Commission on or about July 1, 1993 (All of such contracts and agreements as heretofore amended and the 1993 Amendments being hereinafter collectively referred to as the "Contracts"),

WHEREAS, among other things, the 1993 Amendments more particularly describe on Exhibit 1 thereto those certain facilities which have been or will be acquired and constructed for the joint use of the City and Big Rivers in the operation, maintenance and control of their respective generating stations under the Contracts, and which facilities are being hereinafter referred to as the "Joint Use Facilities,"

WHEREAS, Exhibit 1 to the 1993 Amendments also describes certain electric system facilities belonging to the City or Big Rivers which are not Joint Use Facilities but are now or will later be located on land or in buildings owned by the other participant under the Contracts, and thus the City and Big Rivers have determined that it is appropriate to execute and record a certain mutual and cross-grant of rights of access, easements of location and use, and easements of ingress and egress (Hereinafter being referred to as the "**Easement Agreement**") pertaining to such facilities and also to the Joint Use Facilities,

WHEREAS, pursuant to the Contracts and ordinances of the City providing for the sale of its electric revenue bonds, an electric generating station consisting of generating units 1 and 2, each described in the Contracts as having 175-megawatt capacity together with certain related facilities which are more particularly described in the Contracts were constructed and are owned by the City and operated under the Contracts with Big Rivers. (Such generating units and facilities being hereinafter collectively referred to as "**Station Two**"),

WHEREAS, the City and Big Rivers have agreed that Station Two must be equipped with a Flue Gas Desulfurization System (Hereinafter being referred to as the "**Station Two FGD System**") to comply with the 1990 Amendments to the Clean Air Act and implementing regulations of the U.S. Environmental Protection Agency (Hereinafter being collectively referred to as the "**Acid Rain Act**"),

WHEREAS, certain facilities now owned by Big Rivers and used in operating the Flue Gas Desulfurization System of Big Rivers' Green Generating Station (Hereinafter being referred to as the "**Green Station FGD System**") can be jointly used by the Green Station and Station Two, thus greatly reducing the cost of the Station Two FGD System,

WHEREAS, under the terms of the Contracts, the costs of the Station Two FGD System are allocated between the City and Big Rivers on the basis of their respective usage of Station Two,

WHEREAS, the City and Big Rivers have agreed that the costs of the Station Two FGD System will require financing in whole or in part by the sale of allowances granted under the Acid Rain Act, funds from the Station Two Renewal and Replacement Fund and the Station Two Operations and Maintenance Fund, and revenues from the respective electric utility systems of the City and Big Rivers,

WHEREAS, virtually all assets of Big Rivers, including the Green Station FGD System and other assets necessary for the performance of the 1993 Amendments, are encumbered by a certain Restated Mortgage and Security Agreement dated as of May 30, 1988 by Big Rivers in favor of the Government and the predecessors in interest of the Banks (Hereinafter being referred to as the "**Mortgage**"), WHEREAS, Big Rivers and the City have conditioned the effectiveness of the 1993 Amendments upon receipt of a satisfactory lien accommodation from the Mortgagees,

WHEREAS, Big Rivers and the City have asked the Mortgagees to accommodate the lien of the Mortgage to the City's rights under the Contracts and the Easement Agreement,

WHEREAS, Big Rivers has asked the Mortgagees to consent for purposes of the Mortgage and also for purposes of the Restructuring Agreement dated as of August 31, 1987, as amended, among Big Rivers, the Government and the predecessors in interest of the Banks (Hereinafter being referred to as the "**Restructuring Agreement**"), and

WHEREAS, the Mortgagees have requested the City to confirm the lien of the Mortgage upon Big Rivers' rights under the Contracts, which rights have been pledged, assigned and conveyed by Big Rivers to the Mortgagees for security purposes under the Mortgage;

NOW, THEREFORE, in consideration of the foregoing, the Mortgagees and the City hereby Agree as follows:

1. Definitions. Any terms used in this instrument but not defined herein shall have the same definitions as recited in the Contracts.

2. *Partial Subordination of Mortgagees' Rights; Joint Use Facilities Rights*. Each of the Mortgagees does hereby, for itself on a several basis, subordinate its mortgage lien and security interest under the Mortgage to the rights and interests of the City (a) in, to and in respect of the Joint Use Facilities, to the extent (but only to the extent) of the rights therein of the City under the Contracts, (b) in, to and in respect of transmission facilities belonging to Big Rivers that are used or useful in connection with Station Two, to the extent (but only to the extent) of the rights therein of the City under Section 15.2(4)(a) of the Power Sales Contract, and (c) under the Easement Agreement. Nothing in this instrument shall be (i) construed as an agreement by any of the Mortgagees to assume, or require the assumption by any transferee of all or any part of any property encumbered by the Mortgage, of any performance obligation of Big Rivers under the Contracts, except as hereinafter in this Section 2 provided, (ii) constitute a waiver of any rights which the Mortgagees may acquire as successors to Big Rivers' rights in Station Two under the Contracts, or (iii) be deemed to subordinate to the rights of, or share with, any person or entity, the rights of the Mortgagees to receive and retain payments arising from any of the payment obligations secured by the Mortgage. The parties hereto agree that any transferee (other than for security purposes) of Joint Use

Facilities shall be obligated to permit the Joint Use Facilities to be operated and maintained in accordance with the Joint Facilities Agreement so long as such transferee retains any interest in any of the Joint Use Facilities and that the rights and obligations under this provision shall run with the land.

3. Rights of Mortgagees in Contracts. The City hereby agrees that whenever it notifies Big Rivers of any default under the Contracts, it will contemporaneously notify each of the Mortgagees in writing of such default and allow them whatever rights to cure such default that Big Rivers may have under the Contracts. The City agrees further that such notice to each of the Mortgagees shall be a condition precedent to the exercise of the City's default remedies under the Contracts, and that, notwithstanding anything in the Contracts to the contrary, the cure period for each of the Mortgagees under this Section 3 shall date from the latest time of the giving of such notice to each of the Mortgagees.

4. Rights of City to Access Transmission. Notwithstanding anything to the contrary contained in this instrument, the rights of the City to purchase access to transmission facilities of Big Rivers, as provided for under terms and conditions more fully set forth in the Contracts, shall not include use of transmission facilities subject to the lien of the Mortgage under any circumstance where such facilities will be used by the City, its successors or assigns, to wheel electric power or energy to any member of Big Rivers, or member of a distribution cooperative that is a member of Big Rivers.

5. No Commitment to Finance any Obligations Incurred. This instrument is given by the Mortgagees and accepted by the City on the express condition that the Mortgagees shall be under no obligation to provide financing to Big Rivers or the City for any obligations or indemnities which Big Rivers or the City may incur under any of the Contracts, any financial arrangements incurred for Station Two or any sale of any emission allowances.

6. Notices. Any notice, consent or request to be given in connection with any of the terms or provisions of this instrument shall be in writing and shall be sent by registered mail, postage prepaid, or delivered:

(i) if to the Government:

Administrator
Rural Electrification Administration
14th & Independence Avenue, S.W.
Washington, D.C. 20250-1500

(ii) if to the Banks:

The Bank of New York
Attention: Albert R. Taylor, Vice President
One Wall Street
New York, NY 10286

Chemical Bank
Attention: Jacqueline C. Dickerson
277 Park Avenue
13th Floor
New York, NY 10172-0087

(iii) if to the City:

For the city of Henderson, Kentucky and the City of Henderson Utility Commission
Attention: Mr. Kendel Bryan
100 Fifth Street
P.O. Box 8
Henderson, Kentucky 42420

(iv) if to Big Rivers

Big Rivers Electric Corporation
Attention: Mr. Paul Schmitz
201 Third Street
P.O. Box 24
Henderson, Kentucky 42420

7. Consent to Cross Easements. For purposes of the Mortgage and the Restructuring Agreement dated as of August 31, 1987, as amended, among Big Rivers, the Government and the predecessors in interest of the Banks, each of the Mortgagees does hereby consent to the execution and recordation of the Easement Agreement.

8. Successors and Assigns. This instrument shall be binding upon the parties hereto, their respective successors and assigns.

9. Effective Date. The effectiveness of this instrument shall commence upon approval by the Kentucky Public Service Commission of the 1993 Amendments.

10. Counterparts. This instrument may be executed in any number of counterparts, each of which shall be deemed to be an original, and all of which shall together constitute one and the same instrument.

IN WITNESS WHEREOF, the Mortgagees and the City have caused this instrument to be duly executed in their behalf, all as of the day and year first written above.

CITY OF HENDERSON, KENTUCKY

By____________________
William L. Newman, Mayor

ATTEST:

____
Joann Roberts, City Clerk
(City Seal)

CITY OF HENDERSON UTILITY COMMISSION

By____________________
B.E. Higginson, Chairman

ATTEST:

____
Dudley H. Everson, Secretary

BIG RIVERS ELECTRIC CORPORATION

By____________________
Morton Henshaw, President

ATTEST:

____
William Briscoe, Secretary

THE BANK OF NEW YORK

By

Date: 9/3/93

Executed by the Mortgagee
in the presence of:

Witnesses

LISA J. SANDLER
Notary Public, State of New York
No. 51-
Qualified in New York County 94
Commission Expires April

CHEMICAL BANK

By Edwin Forti

EDWIN FORTI
MANAGING DIRECTOR
CHEMICAL BANK

Date: 9/3/93

Executed by the Mortgagee
in the presence of:

Witnesses

UNITED STATES OF AMERICA

By
James B. Huff, Sr.
Administrator
Rural Electrification
Administration

ATTEST:

Witness

COUNTY OF HENDERSON
COMMONWEALTH OF KENTUCKY

The foregoing instrument was signed and acknowledged before me by William Newman, Mayor, and attested by Joann Roberts, City Clerk as the act and deed of the CITY OF HENDERSON, Kentucky and as their individual acts and deeds in Henderson County, Kentucky on this 31st day of August, 1993.

IN TESTIMONY WHEREOF, I have placed my hand and seal on this 31st day of August, 1993.

Mary Sue Barron
Notary Public
State at Large

My Commission Expires:
6-23-96

COUNTY OF HENDERSON
COMMONWEALTH OF KENTUCKY

The foregoing instrument was signed and acknowledged before me by B.E. Higginson, Chairman of the CITY OF HENDERSON UTILITY COMMISSION, and attested by Dudley H. Everson, Secretary as the act and deed of the CITY OF HENDERSON UTILITY COMMISSION, Kentucky and as their individual acts and deeds in Henderson County, Kentucky on this 31st day of August, 1993.

IN TESTIMONY WHEREOF, I have placed my hand and seal on this 31st day of August, 1993.

Mary Sue Barron
Notary Public
State at Large

My Commission Expires:
6-23-96

COUNTY OF HENDERSON
COMMONWEALTH OF KENTUCKY

The foregoing instrument was signed and acknowledged before me by Morton Henshaw, President of BIG RIVERS ELECTRIC CORPORATION, and attested by William Briscoe, Secretary as the act and deed of the BIG RIVERS ELECTRIC CORPORATION, Henderson, Kentucky and as their individual acts and deeds in Henderson County, Kentucky on this 27th day of August, 1993.

IN TESTIMONY WHEREOF, I have placed my hand and seal on this 27th day of August, 1993.

Paula Mitchell
Notary Public
State at Large

My Commission Expires:

January 12, 1997

STATE OF ~~NEW YORK~~ District of Columbia)
: ss.:
COUNTY OF ~~NEW YORK~~)

I, E. M. HARVEY, a Notary Public in and for the county and state aforesaid, do hereby certify that ALBERT R. TAYLOR, VICE PRESIDENT of THE BANK OF NEW YORK, a corporation, who is personally known to me to be the same person whose name is subscribed to the foregoing instrument as such VICE PRESIDENT of said corporation, appeared before me this day in person and acknowledged that he, being thereunto duly authorized, signed, sealed and delivered said instrument as his free and voluntary act as such VICE PRESIDENT of said corporation, and as the free and voluntary act of said corporation, for the uses and purposes therein set forth.

Given under my hand and official seal this 7th day of ~~August~~ SEPTEMBER, A.D. 1993.

E M Harvey
Notary Public in and for ~~New York~~
County, ~~New York~~
District of Columbia

(Notarial Seal)

My commission expires: 1-31-94

STATE OF NEW YORK)
: ss.:
COUNTY OF NEW YORK)

I, GERARD M. ANDREACCIO, a Notary Public in and for the county and state aforesaid, do hereby certify that [illegible] MANAGING DIRECTOR of CHEMICAL BANK, a corporation, who is personally known to me to be the same person whose name is subscribed to the foregoing instrument as such ~~Vice President~~ MANAGING DIRECTOR of said corporation, appeared before me this day in person and acknowledged that he, being thereunto duly authorized, signed, sealed and delivered said instrument as his free and voluntary act as such MANAGING DIRECTOR of said corporation, and as the free and voluntary act of said corporation, for the uses and purposes therein set forth.

Given under my hand and official seal this 3rd day of SEPTEMBER ~~August~~, A.D. 1993.

GERARD M. ANDREACCIO NOTARY PUBLIC STATE OF NEW YORK

Gerard M Andreaccio
Notary Public in and for New York County, New York

(Notarial Seal)

My commission expires: GERARD M. ANDREACCIO Notary Public, State of New York No. 24-5079525 Qualified in Nassau County Certificate Filed in New York County Commission Expires January 31, 1995

DISTRICT OF COLUMBIA) SS

On this 7th day of September ~~August~~, 1993, personally appeared before me JAMES B. HUFF, SR., who, being by me duly sworn, did say that he is the Administrator of the Rural Electrification Administration, an agency of UNITED STATES OF AMERICA, and acknowledged to me that, acting under a delegation of authority duly given and evidenced by law and presently in effect, he executed the foregoing instrument as the act and deed of United States of America for the uses and purposes therein mentioned.

IN TESTIMONY WHEREOF I have heretofore set my hand and official seal the day and year last above written.

J M Harvey
Notary Public
residing at Washington, D.C.

(Notarial Seal)

My commission expires: 1-31-94

THIS INSTRUMENT PREPARED BY

Terence M. Brady
Deputy Assistant General Counsel
Room 2349 South Agriculture Building
Washington, D.C. 20250-1400

STATE OF KENTUCKY
COUNTY OF HENDERSON. . . . . Sct.

I, Wilma G. Martin, Clerk of Henderson County, certify that the foregoing agreement was this day at 1:00 O'clock P M. lodged in my said office for record and that I have recorded it, the foregoing and this certificate in my said office.

Given under my hand this 9 day September 19 93

WILMA G. MARTIN
BY: Liz Carlisle D.C.

Recorded this the 9 day of September 1993

At 1:00 P Recorded In Misc. Book 441 Page 696

Henderson County Clerk WILMA G. MARTIN

By: [illegible] D.C.

U.S. DEPARTMENT OF AGRICULTURE
RURAL ELECTRIFICATION ADMINISTRATION

REA BORROWER DESIGNATION Kentucky 62 Big Rivers

THE WITHIN Amendments to Contracts (May 1, 1993 Amendments) among City of Henderson, Kentucky, City of Henderson Utility Commission and Big Rivers Electric Corporation

SUBMITTED BY THE ABOVE DESIGNATED BORROWER PURSUANT TO THE TERMS OF THE LOAN CONTRACT, IS HEREBY APPROVED SOLELY FOR THE PURPOSES OF SUCH CONTRACT.

FOR THE ADMINISTRATOR

DATED

9/7/93

REA FORM 28a REV 5-73

CERTIFICATE

The undersigned, Dudley H. Everson, Secretary of the Utility Commission for the City of Henderson, Kentucky, does hereby certify that the Resolution set out below was adopted at a duly called meeting of the Utility Commission on June 29, 1993, to-wit:

RESOLVED, that the Chairman, B. E. Higginson, is hereby authorized and directed to execute for and in behalf of the Utility Commission AMENDMENTS TO CONTRACTS AMONG CITY OF HENDERSON, KENTUCKY, CITY OF HENDERSON UTILITY COMMISSION AND BIG RIVERS ELECTRIC CORPORATION, the terms and provisions of which agreement are incorporated herein by reference.

Witness the signature of Dudley H. Everson this 29th day of June, 1993.

Dudley H. Everson

Dudley H. Everson, Secretary

CERTIFICATION OF CITY CLERK

I, Joann Roberts, hereby certify that I am the duly qualified and acting City Clerk of the City of Henderson, Henderson County, Kentucky, and that the attached is a true and accurate copy of the Resolution No. 24-93, duly adopted, passed, read and signed, as prescribed by the Kentucky Revised Statutes at a special called meeting of the City Commission of the City of Henderson, Kentucky, held at the regular meeting place on the 29th day of June, 1993, and that the foregoing Resolution authorizing the Mayor of the City of Henderson, Kentucky, to execute AMENDMENTS TO CONTRACTS AMONG CITY OF HENDERSON, KENTUCKY, CITY OF HENDERSON UTILITY COMMISSION AND BIG RIVERS ELECTRIC CORPORATION has been duly recorded in the official records of said City.

IN WITNESS WHEREOF, I have hereunto set my hand as City Clerk and affixed hereto the official seal of said City, this the 29th day of June, 1993.

Joann Roberts

Joann Roberts, City Clerk

(City Seal)

RESOLUTION NO. 24-93

RESOLUTION AUTHORIZING THE MAYOR
TO EXECUTE AN AGREEMENT AMENDING CONTRACTS
AMONG THE CITY OF HENDERSON, KENTUCKY, THE CITY OF
HENDERSON UTILITY COMMISSION AND BIG RIVERS ELECTRIC CORPORATION

WHEREAS, the Henderson Utility Commission has requested the Board of Commissioners to approve certain amendments to the Power Sales Contract, Power Plant Construction & Operation Agreement, and Joint Facilities Agreement relating to the operation of the City's Station Two electric generating facility and the allocation of power from said facility; and

WHEREAS, the amendments to the aforesaid contracts are necessary and advisable to accommodate the construction and installation of a flue gas desulfurization system (scrubbers) at Station Two;

NOW THEREFORE, be it resolved by the Board of Commissioners for the City of Henderson, Kentucky:

1. The Mayor, William L. Newman, be and he hereby is authorized and directed to execute for and in behalf of the City a certain AMENDMENTS TO CONTRACTS AMONG CITY OF HENDERSON, KENTUCKY, CITY OF HENDERSON UTILITY COMMISSION AND BIG RIVERS ELECTRIC CORPORATION, the terms and provisions of which agreement are incorporated herein by reference.

2. This Resolution shall become effective immediately upon its passage.

On motion of Commissioner Mike Farmer, seconded by Commissioner Bill Womack that the foregoing Resolution be adopted, the vote was called. On roll call the vote stood:

Commissioner Taylor:	ABSENT:
Commissioner Farmer:	AYE:
Commissioner Johnson:	AYE:
Commissioner Womack:	AYE:
Mayor Newman:	AYE:

EXCERPT FROM THE M[illegible]UTES OF REGULAR MEETING OF B[illegible]RD OF DIRECTORS
OF BIG RIVERS ELECTRIC CORPORATION
HELD IN HENDERSON, KENTUCKY, ON
JULY 9, 1993

On motion of Director Hamilton, seconded by Director Cooper, and carried by unanimous vote, of the directors as declared by the President, the following resolutions were adopted:

RESOLVED that execution by Morton Henshaw, President of Big Rivers Electric Corporation, as attested by William B. Briscoe, Secretary of the corporation, of the "May 1, 1993, Amendments" between the City of Henderson, Kentucky, the City of Henderson Utility Commission, and Big Rivers Electric Corporation be ratified and approved, these Amendments having previously been approved by the Board, but not executed by all the parties until the 29th day of June, 1993.

I, William B. Briscoe, Secretary-Treasurer of the Board of Directors of Big Rivers Electric Corporation hereby certify that the above is a true and correct excerpt from the minutes of Regular Meeting of said Corporation held on 7-9-93.

William B. Briscoe

EXCERPT FROM THE MINUTES OF REGULAR MEETING OF BOARD OF DIRECTORS
OF BIG RIVERS ELECTRIC CORPORATION
HELD IN HENDERSON, KENTUCKY, ON
MARCH 12, 1993

Director Hamilton moved that the amendments to all contracts among the City of Henderson, Kentucky, City of Henderson Utility Commission, and Big Rivers Electric Corporation be approved as presented and that the President be authorized to execute said amendments with management and corporate counsel authorized to make minor changes as deemed necessary. Director Powers seconded the motion which carried by unanimous vote.

I, William B. Briscoe, Secretary-Treasurer of the Board of Directors of Big Rivers Electric Corporation hereby certify that the above is a true and correct excerpt from the minutes of Regular Meeting of said Corporation held on 3-12-93.

AMENDMENTS TO CONTRACTS
AMONG CITY OF HENDERSON, KENTUCKY
CITY OF HENDERSON UTILITY COMMISSION
AND BIG RIVERS ELECTRIC CORPORATION

These Amendments entered into as of May 1, 1993 (the "May 1, 1993 Amendments") by and between City of Henderson, Kentucky, a municipal corporation and city of the second class organized under the laws of Kentucky, of 222 First Street, Henderson, KY 42420, City of Henderson Utility Commission, a public body politic and corporate organized under Kentucky Revised Statutes 96.520 and related statutes, of 100 Fifth Street, Henderson, KY 42420, the said City and Commission being referred to herein collectively as "City", and Big Rivers Electric Corporation, a rural electric cooperative corporation organized under Chapter 279 of the Kentucky Revised Statutes, P.O. Box 24, 201 Third Street, Henderson, KY 42420, known as "Big Rivers" herein.

<u>WITNESSETH:</u>

WHEREAS, the parties hereto are parties to a Power Sales Contract, a Power Plant Construction and Operation Agreement and a Joint Facilities Agreement all dated August 1, 1970 and Big Rivers and City of Henderson Utility Commission are parties to an Agreement For Transmission and Transformation Capacity dated April 11, 1975, the Spare Transformer Agreement dated July 11, 1972, the System Reserves Agreement dated January 1, 1974, the Agreement of April 8, 1980 regarding O&M and R&R Funds, and the Agreement of February 15, 1991 concerning Administrative and General Costs, all of such contracts and agreements as amended being known herein as the "Contracts" and incorporated herein by reference, and

WHEREAS, pursuant to the Contracts, and to ordinances of the City of Henderson, Kentucky providing for the sale of its electric revenue bonds, an electric generating station consisting of generating Units 1 and 2, each described in the Contracts as having 175-megawatt capacity, and related facilities all known herein as "Station Two", were constructed and are now owned by the City of Henderson, Kentucky and operated under the Contracts with Big Rivers, and

WHEREAS, City and Big Rivers have agreed that Station Two must be equipped with a Flue Gas Desulfurization System ("known herein as the "Station Two FGD System") to comply with the 1990 Amendments to the Clean Air Act (Acid Rain Act), and

WHEREAS, certain facilities now owned by Big Rivers subject to certain mortgage liens, and used in operating the FGD System of Big Rivers' Green Generating Station, can be used jointly by the Green Station and by Station Two, thus greatly reducing the cost of the Station Two FGD System, and

WHEREAS, the Station Two FGD System will require financing in whole or in part by sale of emission allowances granted under the Acid Rain Act, funds from the Station Two Renewal and Replacement Fund and the Station Two Operations and Maintenance Fund, and revenues from the respective electric utility systems of the parties hereto.

NOW, THEREFORE, in order to comply with the Acid Rain Act, and provide for the financing, construction, and operation of the Station Two FGD System as a part of Station Two, and in consideration of the mutual covenants herein contained, it is covenanted and agreed among the parties hereto as follows:

ALL CONTRACTS

1. The terms of all of the Contracts except the Joint Facilities Agreement and the Agreement for Transmission and Transformation Capacity shall terminate on October 31, 2003, unless otherwise terminated, or extended, as herein provided. Unless otherwise terminated, or extended, as herein provided, the Joint Facilities Agreement shall terminate in accordance with Section 8 of said Agreement, and the Agreement for Transmission and Transformation Capacity shall terminate in accordance with Section 7.2 of said Agreement.

Big Rivers shall have three options for extending the terms of the Contracts, as amended, on the same terms and conditions thereof, as follows:

1.1 By written notice to City on or before October 31, 1998, to extend the terms for the operating life of Station Two, the operating life of which shall be considered to continue for so long as Unit One and Unit Two, or either of them, is operated, or is capable of normal, continuous, reliable operation for the economically competitive production of electricity, temporary outages excepted.

1.2 If Big Rivers does not exercise the option granted in subparagraph 1.1, by written notice to City on or before October 31, 1998, Big Rivers may extend the terms for five years from October 31, 2003 to October 31, 2008.

1.3 If Big Rivers exercises the option granted in 1.2, by written notice to City on or before October 31, 2003, Big Rivers may extend the terms for an additional five year term from October 31, 2008 to October 31, 2013.

1.4 Notwithstanding any other provision in the Contracts, (a) all of them, except the Joint Facilities Agreement and the Agreement for Transmission and Transformation Capacity, and any options for their renewal, shall terminate 90 days after Big Rivers allocation of capacity from City's Station Two shall be zero, and (b) the terms of all of the Contracts shall be extended automatically until all Station Two revenue bonds of the City of Henderson which have been approved by Big Rivers have been paid.

2. The Contract Year of all of the Contracts shall commence on June 1 and end on May 31 of each year to conform to City's fiscal year, except that the Contract Year for the last year of the Contracts shall end on the last day of the term then in effect.

3. The effective date of these May 1, 1993 Amendments shall be the date following their execution upon which the last of all required approvals and creditors' lien subordinations or accommodations satisfactory to the parties hereof have been obtained, including approvals of the Rural Electrification Administration, the Kentucky Public Service Commission, and any other public regulatory body whose approval is required, provided, however, that the effective date shall then be retroactive to February 1, 1993.

4. Nothing herein contained shall constitute general

obligations of the City of Henderson within Kentucky Constitutional restrictions on such obligations. The obligations herein imposed on City of Henderson shall be borne entirely from revenues or other legally available funds of City's electric light and power system.

POWER SALES CONTRACT

5. THE POWER SALES CONTRACT OF AUGUST 1, 1970, AS HERETOFORE AMENDED, IS FURTHER AMENDED AS FOLLOWS:

5.1 SECTION 2.2 IS AMENDED TO READ AS FOLLOWS:

Station Two: City's 350-megawatt generating station (now rated at 315 MW net send out capacity), located at a site on Green River in Henderson County, Kentucky, and, to the extent furnished and owned by City, all auxiliary facilities, joint use facilities and related facilities, additions, expansions and improvements thereto, including the Station Two FGD System added thereto, and renewals and replacements, but excluding the City Transmission and Transformation Facilities as herein defined, and excluding facilities furnished and owned by Big Rivers. The ownership and location of Station Two, and auxiliary, joint use and related facilities thereon as owned or to be owned by City, and those furnished and owned or to be owned by Big Rivers are shown in Exhibits 1 and 2 hereto.

5.2 SECTION 3.3 IS AMENDED TO READ AS FOLLOWS:

The capacity of the Station Two which is surplus to the City's needs will be allotted to Big Rivers on the basis of five years advance written notice from the City, and Big Rivers shall have the right to receive, and the obligation to take and pay for the capacity of Station Two so allotted to it in the manner herein provided. City may adjust its five year projection of capacity needs in an amount not to exceed five (5) megawatts in any one contract year. Any capacity not utilized by City may be used by Big Rivers. The present allocation of Station Two capacity is 82.86% to Big Rivers and 17.14% to City.

5.3 SECTION 3.6 AS AMENDED BY AMENDMENT NUMBER ONE OF MARCH 2, 1971 IS AMENDED TO READ AS FOLLOWS:

The Total Capacity of Station Two as referred to herein shall be the average of the total continuous net send-out capability of all generating units in Station Two. The parties agree that the present total capacity is 315-megawatts. The parties recognize that Station Two capacity will be reduced by the power required to operate the Station Two FGD System. Either party hereto may request tests from time to time on thirty days prior notice to determine the current Total Capacity. Such tests shall be of at least twenty-four hours duration under actual load carrying conditions, when the equipment is operated at rated pressure and temperature with all auxiliary equipment in service, and at a power factor of approximately ninety percent (90%). The measurement will be made at the 161 KV metering points at the Station Two Switch Yard.

5.4 SECTION 3.7 IS AMENDED TO READ AS FOLLOWS:

The total continuous net send-out capability of any new unit of Station Two shall be tested on or before the date of commercial operation thereof, and the capacity as thus determined will remain the established Total Capacity of such unit until changed by tests requested by either party.

5.5 SECTION 6.2 IS AMENDED TO READ AS FOLLOWS:

Capacity charges to Big Rivers for any Monthly Billing Period shall be the same proportion of the Total Capacity costs of Station Two for such Monthly Billing Period as Big Rivers allocation of surplus net send-out capacity of Station Two during such Monthly Billing Period bears to the total net send-out capacity of Station Two for such Monthly Billing Period as established pursuant to Section 3 of this Agreement.

5.6 SECTION 6.6 IS AMENDED BY ADDING SUBPARAGRAPH (d) THERETO AS FOLLOWS:

(d) The additional payments described in this Section 6.6 and the fourteen and one-half cents per month per kilowatt of the Total Capacity of Station Two charged to the City as described in Section 13.6 of the Power Plant Construction and Operation Agreement between the parties of August 1, 1970, shall both terminate on October 31, 2003, despite changes in the terms of the Contracts.

5.7 THE FIRST SENTENCE OF SECTION 9.4 IS AMENDED TO READ AS FOLLOWS:

As quickly as is reasonably possible, but in no event later than one hundred twenty (120) days after the end of each Contract Year Big Rivers shall submit to City a detailed statement of the actual capacity costs for all Monthly Billing Periods of such Contract Year, based on the annual audit of accounts provided for in Section 11.

5.8 SECTION 15 IS AMENDED BY ADDING THERETO THE FOLLOWING:

15.2 In addition to and not in substitution for the other remedies of the City provided under this Agreement, or by other legal, equitable, or administrative remedies, if Big Rivers shall default in making any payment properly owing under this Agreement and (a) such default continues for sixty days following written notice thereof by the City to Big Rivers or (b) if an Event of Default occurs under the RESTRUCTURING AGREEMENT dated August 31, 1987 among Big Rivers, the United States of America, acting through the Administrator of Rural Electrification Administration, Manufacturers Hanover Trust Company and Irving Trust Company, and their successors and assigns by reason of which any or all of the creditors therein described declare all debts owing to one or more of such creditors to be due and payable, the City may at any time thereafter have the following additional rights and remedies:

(1) on 5 days prior written notice to Big Rivers, City may, until such default is corrected, make sales to others of power generated by Station Two and allocated hereunder to Big Rivers and shall collect the proceeds from such sales and, subject to the provisions of the Bond Ordinance, shall apply them as a credit to capacity charges owing by Big Rivers to the City, then to payments to Big Rivers on Big Rivers' cost of operation and maintenance of Station Two, including its fuel and lime costs and any excess to Big Rivers until Big Rivers' payment default is corrected.

(2) On thirty days written notice by City to Big Rivers, and if Big Rivers defaults to City have not been corrected, City may terminate all contracts with Big Rivers with respect to Station Two and assume immediate possession and operation of Station Two and sell and subject to the crediting procedure of

subparagraph (3), retain the proceeds of all sales of power generated by Station Two thereafter; provided that no such sales shall replace sales made by Big Rivers and/or its distribution co-op members under then existing contracts.

(3) No rights exercised by City under subparagraphs (1) and (2), or either of them, shall relieve Big Rivers of its continuing obligations to pay that portion of the debt service costs which are allocated to it when such rights were first exercised by City, credited in the case of sales under subparagraph (1) by any revenues provided from the sale of Big Rivers allocated capacity as provided in subparagraph (1) above, and credited in the case of sales under subparagraph (2) by any revenues received from the sale of Big Rivers prior allocation in excess of operation and maintenance costs of Station Two, including fuel and lime costs.

(4) In the exercise of its rights under the preceding subparagraphs (1) and (2), City shall have the right (a) to use Big Rivers transmission system for transmitting power in performance of off system power sales made by City from Station Two at fair market wheeling charges then prevailing in Indiana and Kentucky and (b) continue the use of Joint Use Facilities by bearing the costs thereof calculated according to the Joint Facilities Agreement.

(5) City shall make no sales under the preceding subparagraph (1) on any term or condition which would adversely affect the rights or security of holders of Station Two bonds, or impair or adversely affect the eligibility for tax exemption of interest on such bonds or, if notified by Big Rivers prior to any agreement to make such sales, adversely affect the rights, or security of holders of notes of Big Rivers secured by Big Rivers' interest in the Joint Use Facilities or in the Reid and Green Stations. City shall give Big Rivers written notice five (5) business days prior to entering into any agreement for such sales.

15.3 In addition to, and not in substitution for, the other remedies of Big Rivers provided under this

Agreement, or by any other legal, equitable or administrative remedies, if City defaults in making any payments properly owing under the Contracts and such default continues for 60 days following written notice thereof by Big Rivers to City. Big Rivers may at any time thereafter, if all Station Two Revenue Bonds approved by Big Rivers have been paid, on 30 days written notice by Big Rivers to City, and if City's defaults to Big Rivers have not been corrected, then Big Rivers may terminate all contracts with City with respect to Station Two, in which event Big Rivers shall have the continued right to use of Joint Use Facilities by paying the capacity costs thereof calculated in accordance with the Joint Facilities Agreement.

5.10 SECTION 21.1 AS RENUMBERED TO 22.1 IN THE MARCH 2, 1971 AMENDMENT IS AMENDED AS PROVIDED IN SECTION 1 OF THE MAY 1, 1993 AMENDMENTS.

POWER PLANT CONSTRUCTION AND OPERATION AGREEMENT

6. THE POWER PLANT CONSTRUCTION AND OPERATION AGREEMENT OF AUGUST 1, 1970, AS AMENDED, IS FURTHER AMENDED AS FOLLOWS:

6.1 SECTION 1.3 IS AMENDED BY ADDING THERETO THE FOLLOWING:

Such Interconnection Agreement was supplemented and amended by an Amended Agreement dated October 13, 1981 and by a "FIRST AMENDMENT" dated January 10, 1989 which are in effect.

6.2 SECTION 4 IS AMENDED BY ADDING THE FOLLOWING:

4.5 City, with the approval of Big Rivers, has entered into a Contract dated February 5, 1993 with Wheelabrator Air Pollution Control Inc. for the construction and installation of a portion of the Station Two FGD System. City will enter into such further contracts as are necessary, and as are approved by Big Rivers which approval shall not be unreasonably withheld, to complete the design, construction, installation and operation of the Station Two System. City and Big Rivers shall each immediately seek such permits and approvals as are required of each of them.

4.6 Big Rivers shall provide one engineering representative and one clerk to work with the engineering firm employed by the City as the owner's representative on the Station Two FGD System project. City will provide one representative already assigned to Station Two. The cost of these three representatives, including salaries, benefits and out-of-pocket expenses, shall be considered capital costs of the project.

4.7 All proceeds from the sale of SO_2 allowances allocated to Station Two, from whatsoever source, in excess of those needed for Station Two operation shall be divided between City and Big Rivers in the proportions of 17.14% to City and 82.86% to Big Rivers. The sale of all Station Two allowances shall be approved by the City and Big Rivers.

4.8 Until such time as a sum equal to the net proceeds of the sale of Station Two SO_2 allowances has been paid on the costs of the Station Two FGD System, the parties hereto shall bear such scrubber costs in the proportions of 17.14% to the City and 82.86% to Big Rivers. Thereafter costs of the Station Two FGD System shall be borne in the proportion of capacity allocation established under Section 5.2 of the May 1, 1993 Amendments.

4.9 Except as otherwise agreed by the parties, all invoices for the design, construction and installation of the Station Two FGD System shall be issued to City and paid by City pursuant to Section 4.11 hereof. City shall bill Big Rivers monthly for its share of such costs as determined by Section 4.8 hereof and Big Rivers shall pay such share pursuant to Section 4.10 hereof.

4.10 Big Rivers shall pay the amounts billed to it by City under Section 4.9 hereof to the Trustee from time to time in sufficient amounts to satisfy progress payments required on contracts executed by City for the design, construction and installation of said FGD System. City's remaining portion of the costs for the Station Two FGD System shall be paid by City from time to time in sufficient amounts to satisfy progress payments required on said contracts.

4.11 City shall instruct the Trustee to remit all sums paid under Section 4.10 hereof for the design, construction, and installation of the Station Two FGD System to City for deposit into the Station Two account in the Renewals and Replacement Fund, out of which City shall timely pay all costs due on the Station Two FGD System.

JOINT FACILITIES AGREEMENT

7. THE JOINT FACILITIES AGREEMENT IS AMENDED AS FOLLOWS:

7.1 SECTION 3.1 IS AMENDED BY ADDING THE FOLLOWING:

3.1(a) Big Rivers has heretofore allocated for the continuing joint use of the parties the facilities listed on Exhibit 1, Page 2, Part C hereto.

7.2 SECTION 3.2 IS AMENDED BY ADDING THE FOLLOWING AT THE END THEREOF:

The auxiliary facilities which City has previously allocated for the joint use of the parties are listed in Exhibit 1, Pages 1 and 2, Part B.

7.3 NEW SUBPARAGRAPHS SHALL BE ADDED TO SECTION 3 AS FOLLOWS:

3.3 Big Rivers will allocate for the continuing joint use of the parties in the operation of their respective generating stations (Big Rivers Green Station and City's Station Two) those Green Station FGD System Facilities described in Exhibit 1, Page 3, Part C hereto. For such use, Big Rivers shall be paid by City a prorated share of the annual carrying costs, calculated as:

$$\frac{\text{Station Two net capacity}}{\text{Station Two plus Green Station net capacities}}$$

$$\text{Currently } \frac{315\text{ MW}}{755\text{ MW}}$$

times the net book value of those facilities as of December 31, 1994, i.e. $21,675,601.32, further multiplied by a capital carrying charge rate of 11.5 percent.

City's payment to Big Rivers shall be included as a cost under Paragraph (g) of Section 6.3 of the Power Sales Contract between the parties.

3.4 The costs of operating and maintaining the FGD

Joint Facilities described in Exhibit 1, Page 3, Parts B and C hereto, and the cost of sludge stackout and disposal (including haulage and deposit in appropriate landfills) therefrom, shall be allocated to the Green Station and Station Two (except for the cost of coal and lime which shall be provided by each party for its own use) in the proportions in which the stations put sulfur through the Green and Station Two FGD systems, based upon the tonnage of lime and coal and the sulfur and BTU content of the coal, and calculated as shown in the following example:

REAGENT PREPARATION[1]

1) Assume lime, power, maintenance and labor costs = \$10,000,000/yr.

2) From additive feed flowmeters - 70,000 Tons Per Year (TPY) of lime went to Green absorbers and 45,000 TPY went to Station Two absorbers.

3) The Station Two portion of the "reagent prep" O&M costs:

$$\$10,000,000 \times \left[\frac{45,000}{70,000 + 45,000}\right] = \$3,913,000/\text{yr}$$

4) Assume BREC coal to Station Two is 4% sulfur and 11,200 BTU/lb. HMPL coal to Station Two is 2.6% sulfur and 12,000 BTU/lb.

$$\frac{4\ (19,500)}{11,200} = 6.96 \text{ lb. } SO_2/\text{mmBTU}$$

$$\frac{2.6\ (19,500)}{12,000} = 4.22 \text{ lbs. } SO_2/\text{mmBTU}$$

Where 19,500 is the conversion factor for 2 lbs. of SO_2 per lb. of sulfur, assuming 97.5% of the sulfur in the coal is captured in the flue gas stream.

5) The HMPL portion of Station Two "reagent prep" O & M would be:

$$\$3,913,000 \times \left[\frac{(4.22) \times (\text{HMPL coal BTU burn})}{(4.22) \times (\text{HMPL coal BTU burn}) + (6.96) \times (\text{BREC coal BTU burn})}\right]$$

[1] The reagent preparation facilities and the waste treatment facilities are located in separate areas.

if for example: the HMPL coal BTU burn were: $2,977,555 \times 10^6$
the BREC coal BTU burn were: $11,143,418 \times 10^6$

then the HMPL portion comes to $546,200/yr.

WASTE TREATMENT

The "waste treatment" area power, maintenance and labor costs and the scrubber sludge disposal and storage costs would be split similarly, except that Green and HMPL bleed flowmeters would be used to calculate TPY of waste to be treated and stored. The TPY of waste treated would be used in step (2) instead of TPY lime.

7.4 THE SECOND SENTENCE OF SECTION 4.1 IS AMENDED TO READ AS FOLLOWS:

Title to those joint use facilities or portions thereof provided by Big Rivers, including the FGD Joint Facilities, will remain in Big Rivers, and all such facilities will be clearly and permanently marked as the property of Big Rivers.

7.5 SECTION 5.1 IS AMENDED TO READ AS FOLLOWS:

5.1 The costs of providing City's joint use facilities and of modifying Big Rivers' joint use facilities (other than the FGD Scrubber facilities) as provided herein have been paid out of the proceeds of the Station Two Bonds. The cost of modifying the Joint Use Facilities described in Exhibit 1, Page 3, Parts B & C for use by Big Rivers' Green Station and the City's Station Two shall be allocated to Station Two. The cost of additional modifications shall be allocated between Big Rivers' Green Station and the City's Station Two using the methodology provided in Section 13.8 of the Power Plant Construction and Operation Agreement. The amounts so allocated to City's Station Two shall be further allocated between Big Rivers and City in the proportion of capacity allocation established under Section 5.2 of the May 1, 1993 Amendments. Subject to the provisions of Sections 3.3 and 3.4 of this Agreement, the costs of operating, maintaining, repairing, renewing, replacing, and adding to such joint use facilities shall be allocated to the parties' respective generating stations as provided in Section 13 of the parties' Power Plant Construction and Operation Agreement.

STATION TWO DECOMMISSIONING COSTS

8. If Big Rivers exercises its option under Section 1.1 of

the May 1, 1993 Amendments to extend the life of the Contracts for the operating life of Station Two, as heretofore defined, the parties shall bear decommissioning costs of Station Two in the proportions in which they shared capacity costs during the life of Station Two.

IN TESTIMONY WHEREOF, the parties hereto have executed this Agreement in multiple counterparts as of the date first herein written.

This 29th day of June, 1993.

CITY OF HENDERSON, KENTUCKY

By William L. Newman
William L. Newman, Mayor

ATTEST:

Joann Roberts
City Clerk

(City Seal)

CITY OF HENDERSON UTILITY COMMISSION

By B. E. Higgins
Chairman

ATTEST:

Dudley H. Emerson
Secretary

BIG RIVERS ELECTRIC CORPORATION

By Morton Henshaw
Morton Henshaw, President

ATTEST:

William R. Briscoe
William Briscoe, Secretary

June 25, 1993

Kendel Bryan, General Manager
City of Henderson Utility Commission
P.O. Box 8, 100 5th Street
Henderson, KY 42420

Dear Kendel:

In accordance with your message to Travis Housley, and in lieu of amending Exhibit 1 to the May 1, 1993 Amendments, this letter is to confirm that the following three items are included within the Etc., Part B, Item 20, as "Joint Use Facilities provided by and owned by the City but located on Big Rivers property":

1. Unit heat and air conditioner units for the substation control building;

2. Outdoor substation lighting and control building lighting; and

3. Prefabricated metal control building, with reinforced concrete foundation.

If this conforms to your understanding, please sign both copies of this letter, keep one for your files and return one to me for my file.

Sincerely yours,

BIG RIVERS ELECTRIC CORPORATION

By: P.A. Schmitz
P.A. Schmitz, General Manager

This letter correctly states our understanding and agreement.

Dated this 30 day of June, 1993.

CITY OF HENDERSON UTILITY COMMISSION

By: Kendel D Bryan
Kendel Bryan, General Manager

EXISTING HMP&L STATION TWO FACILITIES

PART A. All Station Two facilities located on City property are owned by the City of Henderson Utility Commission except the BTG control board for Big Rivers' Reid Unit 1. This property is indicated as areas A and B on Exhibit 2. The Reid control board is now located in the Station Two control room. The Station Two facilities are:

1. Two Cooling Towers, Ecodyne Model 670-2-71011, S/N E-70-12783 and E-70-12784
2. Four Circulating Water Pumps, Byron Jackson Model 57RXM S/N 711-C-1621, 711-C-1622, 711-C-1623, and 711-C-1624
3. One Turbine Building including Control Room, Switchgear, Fans, Pumps, Motors, Coal Pulverizers and Other Plant Auxiliary Equipment.
4. Two Steam Generators, Riley Stoker, National Board Nos. 2292 (repair no. 390) and 2379, S/N 3576 and 3675.
5. Two Turbine Generators, One General Electric S/N 178863, One Westinghouse S/N 13A43311/43321
6. Two Electrostatic Precipitators, Research Cottrell, Model No. 811LC52F9X30
7. One Chimney, 350 feet tall, concrete shell with brick liner, serving both units

PART B. Joint Use Facilities Provided By and Owned By the City But Located on Big Rivers' Property.

1. Barge Mooring Cells Nos. 1N, 2N, 3N, 4N, 1S, 2S, 3S and 4S as shown on Burns & Roe Drawing No. 04-3280-S3200
2. One Coal Barge Unloader, McDowell Wellman, 1000 net ton/hr capacity
3. Eight Coal Conveyors 1, 2, 3A, 3B, 4A, 4B, 5B and 6B, as shown on attached Exhibit 2
4. One Reclaim Hopper which feeds coal conveyors 4A and 4B
5. One Crusher House fed by conveyor No. 1
6. One Tugboat - The "William Newman" 37 feet long, 21.27 gross tons, 14.0 net tons, coastguard capacity 350 HP
7. One Water Treatment Plant With Demineralizer Building and associated equipment
8. One 50,000 Gallon Capacity Fuel Oil Storage Tank & Distribution System
9. One Flyash Silo, Sump & System Components
10. One Prefab Metal Warehouse adjacent to Fly Ash Silo
11. Coal Handling Equipment As Listed In Continuous Property Records
12. One Lot of Materials & Spare Parts in Big Rivers Warehouse No. 15 as defined by inventory control records
13. One Ash Pond and Effluent Lines
14. Circulating Water Lines as shown on attached Exhibit 2
15. Station Two Ash Pond Dredgings in Green Station Sludge Disposal Landfill adjacent to Green River south of Green Station
16. Four 161KV Oil Circuit Breakers, General Electric, S/N 0139A7206208, 0139A7206209, 0139A7206212, 0139A7206213, located in Plant Switchyard.
17. Two Step-up Transformers, McGraw Edison, S/N C-04280-5-1, C-04280-5-2, located in Plant Switchyard.
18. Two Auxiliary Transformers, Westinghouse, S/N RCP 37261, RCP 37262, located in Plant Switchyard.

19. One Excitation Transformer, General Electric, S/N D-597562, located in Plant Switchyard.
20. One Lot of Line Terminal Structures, Bus, Relay Panels, Etc., located in Plant Switchyard as shown on attached Exhibit 2.

PART C. Joint Use Facilities Owned by Big Rivers and located on Big Rivers property

1. Reid Intake Structure, Two Pumps, and Circulating Water System to serve Reid Unit 1
2. Coal System Crusher Tower supplied by coal conveyors 4A and 4B
3. Coal Conveyors Number 5A and 6A as shown on attached Exhibit 2
4. Plant Entrance Roads from highways 2096 and 2097 and Two Concrete Block Guardhouses
5. Reid Office Building and Maintenance Shop
6. Reid Grounding Transformer Eastern S/N PMR427988
7. Sewage Treatment Facility for Reid, Green and HMP&L Station Two power plants
8. Fire Water System for Reid Station
9. Switchyard Control House for Breaker Controls as shown on attached Exhibit 2

PART D. Other Facilities Owned by the City of Henderson Utility Commission But Not Classified as Joint Use Facilities, a portion or all of which is located on Big Rivers property

1. One 161KV Line from Reid EHV Substation to City Substation No. 4.
2. One Line Terminal Bay and Associated Equipment in Reid EHV Substation for City 161KV Line to City Substation No. 4.
3. Fifty Percent (50%) Ownership of 161/69 KV Transformer G1, Westinghouse, S/N RLP 15941) at Henderson County Substation, and related substation facilities.
4. Ten Percent (10%) Ownership of Big Rivers 161KV Line from Station Two Switchyard to Henderson County Substation.
5. Forty Percent (40%) Ownership of Spare Step Up Transformer (General Electric S/N K 547026) & Railcar (No. BREX 242).
6. One 69KV Transmission Line from plant switchyard to City Substation No. 2

PROPOSED HMP&L STATION TWO
FACILITIES FOR FGD SCRUBBER SYSTEM

PART A. Station Two FGD Facilities To Be Owned by City of Henderson on Big Rivers Property

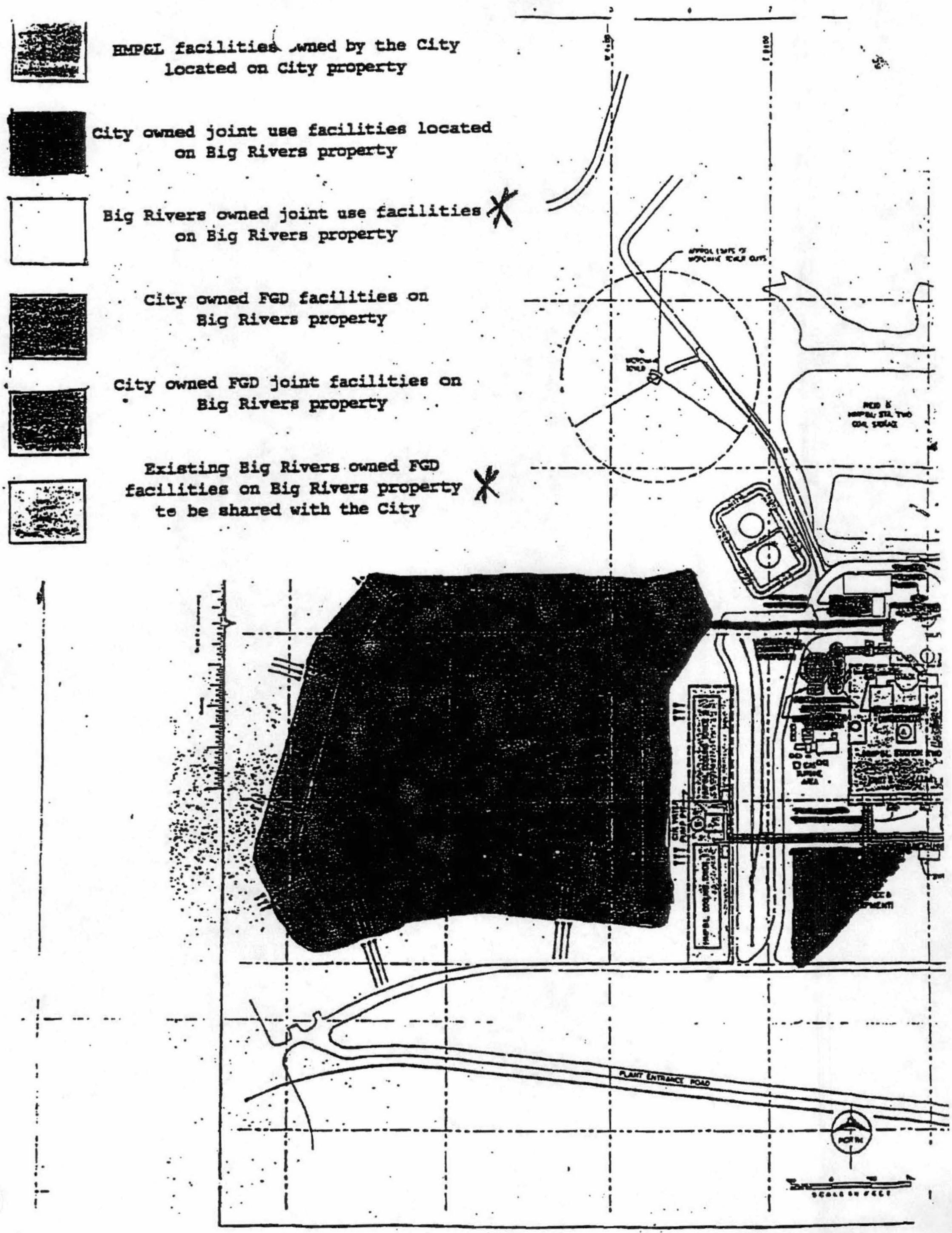
1. FGD System Chimney, 350' Tall
2. Two Wheelabrator Absorber Modules, Building & Associated Equipment
3. Two Booster Fans
4. Auxiliary Building as shown on attached Exhibit 2 containing Controls and Electrical Equipment, Maintenance, Locker and Shower Facilities
5. One Station Two Slaker Building Enclosing Three Slaking Tanks & Equipment
6. One Station Two Additive Hold Tank
7. Two Lime Feed Conveyors from Big Rivers' Green Station Lime Storage Silos 2C1 & 2C2
8. Two Additive Feed Systems; Station Two Scrubber System Includes Pipe & Pipe Rack
9. Two Bleed Slurry Systems to Big Rivers' Green Station Primary Dewatering System Including Pipe, Pipe Rack & Splitter Boxes
10. Two New Thickener Return Water Tanks & Controls
11. One New Filtrate Surge Tank and Controls
12. One Electrical Power Supply for FGD System, with redundant feeds including power transformer, bus work, relay panels and metering equipment

PART B. FGD Joint Use Facilities To Be Owned by City of Henderson on Big Rivers Property

1. Two Lime Slaking Water Pumps and Lines to Slaking Building
2. Two Pug Mill Mixers (Listed Manufacturer and Serial Nos. when known)
3. One Vacuum Filter and Associated Equipment Including Building Expansion as shown on attached Exhibit 2
4. Two New Thickener Underflow Lines and Two Flow Monitors
5. Two Control Systems on Big Rivers' Green Station Thickener Return Water Tanks

PART C. Existing Facilities Owned By Big Rivers Electric For Green Station FGD System As Shown On Attached Exhibit 2 Which Will Be Jointly Used By Green Station and HMP&L Station Two And Which Are Located On Big Rivers Property

1. One Lime Barge Unloader, Dravo Wellman 200/400 Net Ton/Hr Capacity For Lime, 1500 Net Ton/Hr Capacity For Coal
2. One Lime Conveyor L1 and Transfer Tower As Shown On Exhibit 2
3. Two Lime Silos: 2C1 and 2C2 As Shown On Exhibit 2, and Six Lime Screw Conveyors: 2CW-LFC, 2CE-LFC, 2C1-SC, 2C2-SC, 1CW-LFC, 1CE-LFC
4. Four Thickeners for Primary Dewatering of Bleed Slurry: 1A, 1B, 2A, 2B, Including Tunnels, Pumps, and Ventilation Systems
5. One Secondary Dewatering System and Sludge Stackout System, Including Solid Waste Building and Sludge Stackout Area as Shown on Exhibit 2; Three Vacuum Filters with Feed Systems: FL-1A, FL-1B, FL-1C; Eleven Filter Cake Conveyors and Radial Stackers: CO-1A, CO-1B, CO-1C, CO-2A, CO-2B, CO-3A, CO-3B, CO-6A, CO-6B, CO-7A, CO-7B; and Four Fly-Ash Screw Conveyors
6. Two Ash Silos and Pneumatic Transfer System
7. Two Green Station River Water Clarifiers: CL-101 and CL-102, with Three Slaker Water Pumps: 1A, 1B and 2A
8. One Solid Waste Loader, Hitachi S/N 171-0373
9. One Sludge Haul Road and Two Truck Scales


HMP&L facilities owned by the City located on City property
City owned joint use facilities located on Big Rivers property
Big Rivers owned joint use facilities on Big Rivers property
City owned FGD facilities on Big Rivers property
City owned FGD joint facilities on Big Rivers property
Existing Big Rivers owned FGD facilities on Big Rivers property to be shared with the City
PLANT ENTRANCE ROAD

BIG RIVERS ELECTRIC CORPORATION

INTEROFFICE CORRESPONDENCE

TO: Distribution List

FROM: Steve Jackson SMJ

DATE: May 12, 1993

RE: HMP&L Station Two and Joint Use Facilities Description

The attached documents were generated to address REA concerns expressed in review of the proposed amendment to the Big Rivers agreement with the City of Henderson. The documents attempt to provide a description of the equipment and property at the Reid, Station Two and Green site that are solely or jointly owned by the City or that are joint use facilities which each party has a right to use for the operation of their respective generating units. In addition these documents address the equipment that will be added for and shared between the Station Two scrubber and the Green Station scrubber in the same manner. The attached documents are:

Exhibit 1 pages 1 to 3: written description of existing and proposed Station Two and joint use facilities.

Exhibit 2 : General Arrangement Site Plan drawing depicting the equipment described in Exhibit 1 when possible.

Annex 1,2 and 3 revised to match the information provided in Exhibit 1.

These documents have been provided to Mr. Morton Holbrook, Mr. Henry Neel and the REA. Please review them and provide me any comments or revisions required as soon as possible.

<u>Distribution List</u>

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BIG RIVERS ELECTRIC CORPORATION

May 14, 1993

Mr. Morton Holbrook
Holbrook, Wible, Sullivan & Mountjoy, P.S.C.
100 St. Ann Building
P.O. Box 727
Owensboro, KY 42302-0727

Dear Mr. Holbrook:

Enclosed is one copy of the Green/Station Two Shared Facilities Study report prepared by Burns and McDonnell. This report documents the adequacy of the existing Green Station FGD facilities and the equipment additions and modifications needed to handle the combined capacity for Green and Station Two FGD systems. This report is being provided in order to address the concern expressed by Mr. Steve Slovikosky of the REA. He felt this document would provide them the ability to answer any questions that might be raised concerning the ability to share the Green FGD facilities with Station Two.

There are two minor modifications to the Lime Slaking and Slurry Feed system arrangement outlined in the report. These changes are a result of review and approval of the system arrangement outlined by Wheelabrator in their proposal. The changes include:

1. A single drag chain conveyor will feed lime from two existing lime silos and their screw conveyors instead of a dual drag chain conveyor system feeding from all four silos as proposed in the study.

2. The system will include two slurry feed loops, but only one slurry hold tank. Instead of the additional tank, a crosstie system will be provided with the Green Station slurry hold tanks to allow additional capacity by transfer of slurry from the other tanks.

By copy of this letter, we are providing this report to Mr. Terry Brady and Mr. Steve Slovikosky.

Let us know if any additional information is required.

Sincerely,

James H. McIlwain

James H. McIlwain
Manager of Construction

cc: Terry Brady, Esq. - REA
Steve Slovikosky - REA

Post Office Box 24, Henderson, KY 42420 Telephone 502-827-2561

EXISTING HMP&L STATION TWO FACILITIES

All Station Two facilities located on City property are owned by the City of Henderson Utility Commission except the BTG control board for Big Rivers' Reid Unit 1. This property is indicated as areas A and B on Exhibit 2. The Reid control board is now located in the Station Two control room. The Station Two facilities are:

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6. Two Electrostatic Precipitators, Research Cottrell, Model No. B11LC52F9X30
7. One Chimney, 350 feet tall, concrete shell with brick liner, serving both units

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3. Eight Coal Conveyors 1, 2, 3A, 3B, 4A, 4B, 5B and 6B, as shown on attached Exhibit 2
4. One Reclaim Hopper which feeds coal conveyors 4A and 4B
5. One Crusher House fed by conveyor No. 1
6. One Tugboat - The "William Newman" 37 feet long, 21.27 gross tons, 14.0 net tons, coastguard capacity 350 HP
7. One Water Treatment Plant With Demineralizer Building and associated equipment
8. One 50,000 Gallon Capacity Fuel Oil Storage Tank & Distribution System
9. One Flyash Silo, Sump & System Components
10. One Prefab Metal Warehouse adjacent to Fly Ash Silo
11. One Coal Handling Equipment As Listed In Continuous Property Records
12. One Lot of Materials & Spare Parts in Big Rivers Warehouse No. 15 as defined by inventory control records
13. One Ash Pond and Effluent Lines
14. Circulating Water Lines as shown on attached Exhibit 2
15. Station Two Ash Pond Dredgings in Green Station Sludge Disposal Landfill adjacent to Green River south of Green Station
16. Four 161KV Oil Circuit Breakers, General Electric, S/N 0139A7206208, 0139A7206209, 0139A7206212, 0139A7206213, located in Plant Switchyard.
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18. Two Auxiliary Transformers, Westinghouse, S/N RCP 37261, RCP 37262, located in Plant Switchyard.

19. One Excitation Transformer, General Electric , S/N D-597562, located in Plant Switchyard.
20. One Lot of Line Terminal Structures, Bus, Relay Panels, Etc., located in Plant Switchyard as shown on attached Exhibit 2

Joint Use Facilities Owned by Big Rivers and located on Big Rivers property

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2. Coal System Crusher Tower supplied by coal conveyors 4A and 4B
3. Coal Conveyors Number 5A and 6A as shown on attached Exhibit 2
4. Plant Entrance Roads from highways 2096 and 2097 and Two Concrete Block Guardhouses
5. Reid Office Building and Maintenance Shop
6. Reid Grounding Transformer Eastern S/N PMR427988
7. Sewage Treatment Facility for Reid, Green and HMP&L Station Two power plants
8. Fire Water System for Reid Station
9. Switchyard Control House for Breaker Controls as shown on attached Exhibit 2

Other Facilities Owned by the City of Henderson Utility Commission But Not Classified as Joint Use Facilities, a portion or all of which is located on Big Rivers property

1. One 161KV Line from Reid EHV Substation to City Substation No. 5.
2. One Line Terminal Bay and Associated Equipment in Reid EHV Substation for City 161KV Line to City Substation No. 5.
3. Fifty Percent (50%) Ownership of 161/69 KV Transformer G1, Westinghouse, S/N RLP 15941) at Henderson County Substation.
4. Ten Percent (10%) Ownership of Big Rivers 161KV Line from Station Two Switchyard to Henderson County Substation.
5. Forty Percent (40%) Ownership of Spare Step Up Transformer (General Electric S/N K 547026) & Railcar (No. BREX 242).
6. One 69KV Transmission Line from plant switchyard to City Substation No. 2

PROPOSED HMP&L STATION TWO
FACILITIES FOR FGD SCRUBBER SYSTEM

FGD Joint Facilities To Be Owned by City of Henderson on Big Rivers Property

1. FGD System Chimney, 350' Tall
2. Two Wheelabrator Absorber Modules, Building & Associated Equipment
3. Two Booster Fans
4. Auxiliary Building as shown on attached Exhibit 2 containing Controls and Electrical Equipment, Maintenance, Locker and Shower Facilities
5. One Station Two Slaker Building Enclosing Three Slaking Tanks & Equipment
6. One Station Two Additive Hold Tank
7. Two Lime Slaking Water Pumps and Lines to Slaking Building
8. Two Lime Feed Conveyors from Big Rivers' Green Station Lime Storage Silos 2C1 & 2C2
9. Two Additive Feed Systems; Station Two Scrubber System Includes Pipe & Pipe Rack
10. Two Bleed Slurry Systems to Big Rivers' Green Station Primary Dewatering System Including Pipe, Pipe Rack & Splitter Boxes
11. Two Pug Mill Mixer (Listed Manufacturer and Serial Nos. when known)
12. One Vacuum Filter and Associated Equipment Including Building Expansion as shown on attached Exhibit 2
13. Two New Thickener Underflow Lines and Two Flow Monitors
14. Two Control Systems on Big Rivers' Green Station Thickener Return Water Tanks
15. Two New Thickener Return Water Tanks & Controls
16. One New Filtrate Surge Tank and Controls
17. One Electrical Power Supply for FGD System, with redundant feeds including 161/4.16KV transformer, bus work, relay panels and metering equipment

Existing Facilities Owned By Big Rivers Electric For Green Station FGD System As Shown On Attached Exhibit 2 Which Will Be Jointly Used By Green Station and HMP&L Station Two And Which Are Located On Big Rivers Property

1. One Lime Barge Unloader, Dravo Wellman 200/400 Net Ton/Hr Capacity For Lime, 1500 Net Ton/Hr Capacity For Coal
2. One Lime Conveyor L1, As Shown On Exhibit 2
3. One Lime Transfer Tower Fed By L1 Conveyor As Shown On Exhibit 2
4. Six Lime Screw Conveyors: 2CW-LFC, 2CE-LFC, 2C1-SC, 2C2-SC, 1CW-LFC, 1CE-LFC
5. Two Lime Silos 2C1 and 2C2 As Shown On Exhibit 2
6. Four Thickeners for Primary Dewatering of Bleed Slurry: 1A, 1B, 2A, 2B
7. Three Vacuum Filters: FL-1A, FL-1B, FL-1C
8. One Filter Feed System To Supply Three Vacuum Filters In Solid Waste Building As Shown On Exhibit 2
9. Two Ash Silos & Feed Systems
10. Eleven Filter Cake Conveyors & Radial Stackers: CO-1A, CO-1B, CO-1C, CO-2A, CO-2B, CO-3A, CO-3B, CO-6A, CO-6B, CO-7A, CO-7B
11. One Sludge Stackout Area As Shown On Exhibit 2
12. Three Existing Slaker Water Pumps: 1A, 1B and 2A
13. Two Green Station River Water Clarifiers: CL-101 and CL-102
14. One Green Station Bottom Ash Sluice Water System
15. One Sludge Haul Road and Two Truck Scales

Listing of Joint Use Facilities Owned by Big Rivers Electric Corporation
and Used in the Operation of Station Two and
Big Rivers' Reid and Green Power Plants and More
Particularly Described In Exhibit 1 and Located On Exhibit 2

1. Reid Intake Structure & Pumps
2. Coal System Crusher Tower
3. Conveyors Number 5A and 6A
4. Plant Entrance Roads and Guardhouses
5. Reid Office Building and Maintenance Shop
6. Reid Grounding Transformer
7. Site Sewage Treatment Facility
8. Fire Water System for Reid Station
9. Switchyard Control House for Breaker Controls

Listing of Joint Use Facilities Owned by City of Henderson Utility Commission and Used in the Operation of Station Two and Big Rivers' Reid and Green Power Plants and More Particularly Described In Exhibit 1 and Located On Exhibit 2

1. Barge Mooring Cells Nos. 1N, 2N, 3N, 4N, 1S, 2S, 3S, and 4S
2. Coal Barge Unloader
3. Coal Conveyors 1, 2, 3A, 3B, 4A, 4B, 5B and 6B
4. Reclaim Hopper
5. Crusher House
6. Tugboat - The "William Newman"
7. Water Treatment & Demineralizer Building & Plant
8. Fuel Oil Storage Tank & Systems
9. Flyash Silo, Sump & System Components
10. Warehouse adjacent to Fly Ash Silo
11. Coal Handling Equipment As Listed In Continuous Property Records
12. One Lot of Materials & Spare Parts in Big Rivers Warehouse No. 15
13. Ash Pond and Effluent Lines
14. Circulating Water Lines
15. Station Two Ash Pond Dredgings in Green Station Sludge Disposal Landfill
16. Four 161KV Oil Circuit Breakers, General Electric, S/N 0139A7206208, 0139A7206209, 0139A7206212, 0139A7206213, located in Plant Switchyard.
17. Two Step-up Transformers, McGraw Edison, S/N C-04280-5-1, C-04280-5-2, located in Plant Switchyard.
18. Two Auxiliary Transformers, Westinghouse, S/N RCP 37261, RCP 37262, located in Plant Switchyard.
19. One Excitation Transformer, General Electric , S/N D-597562, located in plant switchyard.
20. One Lot of Structures, Bus, Relay Panels, Etc., located in Plant Switchyard

FGD JOINT FACILTIES OWNED BY BIG RIVERS

To Which 11.5% Annual Carrying Charge Is To Be Applied

Thickener equipment	$ 889,534.61	Barge Unloader Cells; Foundations	$1,066,270.00
hickener equipment	$ 1,145,429.00	Solid Waste Building Foundations	$ 442,241.00
Lime Silo Equipment	$ 2,423,640.00	Control House; Barge Unloader	$ 20,360.00
Lime Silo Equipment	$ 720,183.00	Electrical Building; Barge Unloader	$ 20,360.00
Foundations, Misc.	$ 8,418,755.91	G2 Clarifier Equip. Building	$ 396,490.00
Foundations, Piping, Conveyors, Valves	$13,769,110.40	Solid Waste Building; Structure	$ 547,042.00
Air Dryer, IU	$ 16,189.41	Air Conditioning System; IUCS Building	$ 2,441.00
Lime Conveyor	$ 5,725.40	Barge Unloader Cab; HVAC Unit	$ 630.00
Barge Unloader	$ 734,852.00	Access Bridge To Unloader Cells	$ 333,449.00
Screw Conveyors	$ 18,879.00	Yard Lighting; Solid Waste Area	$ 6,838.00
Barge Crane	$ 39,844.00	Sludge Haul Road, Both Gravel & Paved	$2,499,207.29
Dust Collectors	$ 385,716.00	Pneumatic Ash Transfer System	$ 503,857.12
Barge Trolley	$ 38,759.00	Improvements and Modifications	$ 169,366.43
arge, Bucket Elev.	$ 211,047.00		
Hoist, Barge Unloader	$ 66,390.00		
Unloader & Cells	$ 4,606,636.98		
Lime Conveyor	$ 2,123,066.00		
Solid Waste Loader	$ 323,633.00		
Clarifier	$ 399,277.00		
Subtotal Column 1	**$36,336,667.71**	**Subtotal Column 2**	**$6,008,551.84**

Installed Value $42,345,219.55

Cost Split Ratio
Green 440 MW--Station Two 315 MW
Station Two Allocation: 315 MW divided by 755 MW = 41.72%

Depreciated Value As Of 12/31/94 $21,675,601.32

Station Two portion is $9,043,061 using the same ratio as determined above

Annual cost at 11.5% is $1,039,952 which would be split between HMP&L and Big Rivers in the same ratio as each party's allocation of Station Two capacity

USDA

United States Department of Agriculture
Rural Development

Rural Business–Cooperative Service • Rural Housing Service • Rural Utilities Service
Washington, DC 20250

[redacted]

RECEIVED
JUL - 6 1998
BIG RIVERS
ELECTRIC CORPORATION

Mr. Michael H. Core
President and CEO
Big Rivers Electric Corporation
P. O. Box 24
Henderson, Kentucky 42420

Dear Mr. Core:

In response to your letter dated May 6, 1998, requesting approval of the 1998 Amendments to Contracts between Big Rivers Electric Corporation and the City of Henderson and the City of Henderson Utility Commission, the Rural Utilities Service (RUS) finds the Amendments acceptable for execution. Executed copies of the documents should be sent to RUS for formal approval.

Should you have any questions, please call me at (202) 720-1265.

Sincerely,

LARRY V. BELLUZZO
Program Advisor
Financial Services Staff

U. S. DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

RUS BORROWER DESIGNATION KY 62 Big Rivers Electric Corp.

THE WITHIN AMENDMENTS TO CONTRACTS AMONG CITY OF HENDERSON,

KENTUCKY, CITY OF HENDERSON UTILITY COMMISSION AND BIG RIVERS

ELECTRIC CORPORATION

SUBMITTED BY THE ABOVE DESIGNATED BORROWER PURSUANT TO THE TERMS OF THE LOAN CONTRACT, IS HEREBY APPROVED SOLELY FOR THE PURPOSES OF SUCH CONTRACT.

FOR THE ADMINISTRATOR

DATED

7/15/98

REA FORM 28a REV. 5-73
Computer Generated Facsimile

AMENDMENTS TO CONTRACTS
AMONG CITY OF HENDERSON, KENTUCKY
CITY OF HENDERSON UTILITY COMMISSION
AND BIG RIVERS ELECTRIC CORPORATION

These Amendments entered into and effective as of July 15, 1998 (the "1998 Amendments") by and between City of Henderson, Kentucky, a municipal corporation and City of the third class organized under the laws of the Commonwealth of Kentucky, of 222 First Street, Henderson, KY 42420, City of Henderson Utility Commission, a public body politic and corporate organized under Kentucky Revised Statutes 96.520 and related statutes, of 100 Fifth Street, Henderson, KY 42420, the said City and Commission being referred to herein collectively as "City," and Big Rivers Electric Corporation, a rural electric cooperative corporation organized under Chapter 279 of the Kentucky Revised Statutes, P.O. Box 24, 201 Third Street, Henderson, KY 42420, known as "Big Rivers" herein.

WITNESSETH:

WHEREAS, the parties hereto are parties to a Power Sales Contract, a Power Plant Construction and Operation Agreement and a Joint Facilities Agreement all dated August 1, 1970 and Big Rivers and City of Henderson Utility Commission are parties to an Agreement for Transmission and Transformation Capacity dated April 11, 1975, the Spare Transformer Agreement dated July 11, 1972, the Systems Reserves Agreement dated January 1, 1974, the Agreement of April 8, 1980 regarding O&M and R&R Funds, and the Agreement of February 15, 1991 concerning Administrative and General Costs, and Amendments to such contracts dated May 1, 1993, all of such contracts and agreements as amended being known herein as the "Contracts" and incorporated herein by reference, and

WHEREAS, pursuant to the Contracts, and to ordinances of the City of Henderson, Kentucky providing for the sale of its electric revenue bonds, an electric generating station consisting of generating Units 1 and 2, each described in the Contracts as having a 175-megawatt capacity, and related facilities all known herein as "Station Two," were constructed and are now owned by the City of Henderson and operated by Big Rivers under the Contracts with Big Rivers, and

WHEREAS, City and Big Rivers now seek to amend the Contracts to reflect new understandings between the parties regarding the Contracts and the business relationship between City and Big Rivers.

NOW THEREFORE, in consideration of the mutual covenants herein contained, it is covenanted and agreed among the parties hereto as follows:

ALL CONTRACTS

1. The terms of all the Contracts except the Joint Facilities Agreement shall be extended for the operating life of Station Two, the operating life of which shall be considered to continue for so long as Unit 1 and Unit 2, or either of them, is operated, or is capable of normal, continuous, reliable operation for the economically competitive production of electricity, temporary outages excepted. Notwithstanding any other provision in the Contracts, all of the Contracts, except the Joint Facilities Agreement and the System Reserves Agreement, shall terminate 90 days after Big Rivers' allocation of capacity from City's Station Two shall be zero; provided, however, that the terms of all the Contracts shall be extended until all Station Two bonds of the City of Henderson which have been approved by Big Rivers have been paid. Notwithstanding the above, the Joint Facilities Agreement shall terminate in accordance with

Section 8 of said Agreement. This section expressly replaces the provisions of Section 1 of the May 1993 Amendments in their entirety.

2. The effective date of these 1998 Amendments shall be the date following their execution upon which the last of the following approvals of the 1998 Amendments is obtained:

2.1 Approval of the Rural Utilities Service; and

2.2 Approval of the Kentucky Public Service Commission.

3. Nothing herein contained shall constitute general obligations of the City of Henderson within Kentucky Constitutional restrictions on such obligations. The obligations herein imposed on City of Henderson shall be borne entirely from revenues or other legally available funds of City's electric light and power system.

POWER SALES CONTRACT

4. The Power Sales Contract of August 1, 1970, as heretofore amended, is further amended as follows:

(a) **SECTION 3.4 IS HEREBY AMENDED TO BE AND READ IN ITS ENTIRETY AS FOLLOWS:**

3.4 City agrees that it will not, after the execution and approval of this Agreement, (1) make any dispositions to others for resale of its generating capacity, other than pursuant to Section 3.8 added by these 1998 Amendments, except for the purpose of disposing of any surpluses resulting from good faith over-estimates of its needs, or (2) add any commercial or industrial customers in excess of thirty (30) megawatts each to its electric system, if to do either (1) or (2), as the case may be, would require the withdrawal of additional capacity from its Existing System and/or from Units One and Two of its Station Two. Expansions in the ordinary course of business of any commercial or industrial plants being served by City at the time of the execution of these 1998 Amendments shall not be considered added commercial or industrial customers subject to the 30 megawatt size limitation for the purposes of this Agreement. Surplus capacity resulting from good faith over estimates as referred to in (1) above shall be first offered to Big Rivers at City's cost. Big Rivers and City understand that City shall be entitled to meet (in increasing incremental amounts, as necessary) the load of any new commercial or industrial customer (which shall not exceed the 30 megawatt cap per customer established above) through its annual adjustment to its five year capacity reservation forecasts in amounts not exceeding five (5) megawatts per Contract Year (as described in Section 3.3 of this Agreement) and its subsequent capacity reservation forecasts under this Agreement.

(b) A NEW SECTION 28 TO POWER SALES CONTRACT IS HEREBY CREATED AND INCLUDED AS FOLLOWS:

28.1 City shall have the right (subject to the further limitations and provisions of this Section 28) to utilize within the City's service territory as of the date of these 1998 Amendments, including all areas within the existing City limits, capacity and energy from Station Two in excess of its reserved capacity allocations, as adjusted under Section 3.3 of this Agreement (such excess capacity and energy being referred to herein as "Station Two Economic Development Power"), to serve up to <u>50%</u> of Economic Development Loads (defined below) of customers to the extent such customers are not otherwise served as of the date of commencement of the proposed service by City from reserved capacity allocations under this Agreement (each an "Economic Development Opportunity"); provided, however, that the maximum amount of Station Two Economic Development Power that may be utilized by City at any time shall not exceed 25 megawatts in the aggregate for all such Economic Development Opportunities, collectively. City's right to utilize Station Two Economic Development Power with respect to any Economic Development Opportunity is further conditioned upon City having made a binding written offer to purchase from Big Rivers, at the applicable rate set forth in Exhibit 1, the capacity and energy requirements of such Economic Development Opportunity not supplied by City with its reserved capacity or with Station Two Economic Development Power to meet such Economic Development Load. For purposes hereof, "Economic Development Load" means the demand for capacity and associated energy of (i) a new customer of City within City's service territory (as described above) or (ii) an existing customer of City in that service territory (as described above) created by a substantial expansion of such customer's plant or facility (defined as a projected annual increase in kWh consumption or kW demand of such customer of 20% or more as a result of a plant expansion). Upon utilization by City of Station Two Economic Development Power, such power shall be treated for purposes of this Agreement, except Section 3.3 and clause (2) of Section 3.4 of this Agreement, as capacity of Station Two reserved to the City hereunder.

28.2 For any Economic Development Opportunity of City as to which City exercises its right under Section 28.1 to retain and utilize Station Two Economic Development Power by providing Big Rivers with a binding written offer to purchase, at the applicable rate set forth in Exhibit 1, the capacity and energy in the aggregate required by City for such Economic Development Opportunity in addition to the City's reserved capacity and Station Two Economic Development Power available under Section 28.1, City hereby agrees that Big Rivers shall have a period of fifteen days following receipt of City's written offer to accept the terms of such offer and to agree to supply the power at the applicable rate in Exhibit 1, over an agreed upon term. If Big Rivers rejects such offer or fails to accept such offer within such fifteen-day period, City shall be entitled to retain and utilize Station Two Economic Development Power in accordance with Section 28.1, and shall be entitled to negotiate with third-party suppliers to provide the remainder of the capacity and energy required to serve the Economic Development Load. Prior to entering into a binding contract with any such third-party supplier, City agrees to offer Big Rivers the right to match the price offered by such third-party supplier over the term offered by such third-party supplier, which right Big Rivers must exercise within five days of receipt of such third-party offer from City. If Big Rivers rejects such offer or fails to accept such offer within such five day period, City shall be free to execute a contract with such third-party supplier, provided, however, that if City shall not have contracted for the purchase of such capacity and energy with such third-party supplier within thirty-days after the expiration of that five-day period, no such contract shall be entered into without again first offering Big Rivers the opportunity to serve such remaining Economic Development Load upon the terms described in the preceding sentence.

28.3 In the event that Big Rivers fails to provide that portion of capacity and energy required to supply an Economic Development Opportunity that it has agreed to supply from Big Rivers' resources, whether at the specified prices contained in Exhibit 1, or upon terms matching those of a third-party supplier in accordance with Section 28.2, as the case may be, City shall be entitled to take from Station Two capacity and energy, in addition to the Station Two Economic Development Power to which City is already entitled, in such amounts as were to have been provided by Big

Rivers, with subsequent adjustments to the allocation of costs in accordance with this Agreement.

28.4 Big Rivers and City agree that the specified rates for capacity and energy contained in Exhibit 1 shall be fixed for a period of seven years after the date these 1998 Amendments become effective. Rates for periods after the date seven years after these 1998 Amendments become effective shall be subject to future negotiation.

(c) **A NEW SECTION 3.8 TO POWER SALES CONTRACT IS HEREBY CREATED AND INCLUDED AS FOLLOWS:**

3.8 Big Rivers and City hereby agree that the following provisions shall apply to energy from capacity not utilized by City or from capacity in excess of the capacity calculated in accordance with Section 3.6 of this Agreement.

(a) In the event that at any time and from time to time City does not take the full amount of energy associated with its reserved capacity from Station Two (determined in accordance with this Agreement), Big Rivers may, at its discretion, take and utilize all such energy (or any portion thereof designated by Big Rivers) not scheduled or taken by City (the "Excess Henderson Energy"), in accordance with Section 3.8(c).

(b) If at any time Station Two capacity is generated in excess of the Total Capacity of Station Two determined in accordance with Section 3.6 of this Agreement ("Excess Henderson Capacity"), Big Rivers shall take and utilize all energy associated with such Excess Henderson Capacity, unless otherwise agreed to by Big Rivers and City, in accordance with Section 3.8(c).

(c) Following the end of each calendar month, Big Rivers shall notify City of the amount of Excess Henderson Energy and energy associated with Excess Henderson Capacity, if any, taken by Big Rivers during the previous month, and Big Rivers shall pay City prior to the 25th day of the then current month for the amount of Excess Henderson Energy and energy associated with the Excess Henderson Capacity so taken by it at a rate equal to $1.50 per mWh. In addition, Big Rivers shall provide, at its own cost, the full replacement of all fuels and reagents consumed from the

Station Two fuel and reagent reserves for the production of the Excess Henderson Energy and energy associated with the Excess Henderson Capacity so taken by it. Further, Big Rivers shall pay the portion of sludge disposal costs attributable to the Excess Henderson Energy and energy associated with Excess Henderson Capacity, as calculated in accordance with Section 3.4 of the Joint Facilities Agreement.

(d) City agrees that Big Rivers, as operator, shall be allowed, but shall not be required, to operate Station Two to obtain capacity above the Total Capacity of Station Two determined in accordance with Section 3.6 of this Agreement. City further agrees that it shall not at any time be permitted to sell or commit to any person other than Big Rivers any Excess Henderson Energy without having first offered Big Rivers the opportunity to purchase such Excess Henderson Energy. Big Rivers shall have a reasonable period of time after submission of the City's scheduled energy requirements to decide whether to purchase any Excess Henderson Energy not scheduled by City. Big Rivers agrees to notify City thereafter if it does not intend to purchase such energy, and agrees to give City a response within a reasonable time so that City may take efforts to resell this power to third-parties. City agrees to compensate Big Rivers according to Big Rivers' Open Access Transmission Tariff to the extent City utilizes any transmission on Big Rivers' transmission system in marketing Excess Henderson Energy.

(d) A NEW SECTION 19.2 TO POWER SALES CONTRACT IS HEREBY CREATED AND INCLUDED AS FOLLOWS:

19.2 Big Rivers and City agree that on or before the date on which the Station Two Bonds are retired, and the remaining balance of monies contained in the Station Two Account in the Renewals and Replacements Fund in accordance with Section 1 of the Agreement dated April 8, 1980 between Big Rivers and City shall have been disbursed, the following shall occur:

(a) Big Rivers shall establish a new Big Rivers Station Two Renewals and Replacements Fund and shall deposit immediately available funds in the amount of $600,000. Thereafter, Big Rivers agrees that each month it shall make levelized payments into the Big Rivers Station Two Renewals and Replacements Fund, not to exceed $50,000 each month, so as to restore a minimum balance of $600,000. All interest on such amounts shall be repaid to Big Rivers at the end of each calendar year, and all amounts in such fund shall be paid to Big Rivers upon termination or expiration of this Agreement. Amounts from this Fund shall be withdrawn in accordance with Section 19.2(c); and

(b) City shall establish a new Henderson Station Two Renewals and Replacements Fund and shall deposit immediately available funds in the amount of $150,000. Thereafter, City agrees that each month it shall make levelized payments into the Henderson Station Two Renewals and Replacements Fund, not to exceed $12,500, so as to restore a minimum balance of $150,000. All interest on such amounts shall be repaid to Henderson at the end of each calendar year and all amounts in such fund shall be paid to City upon termination or expiration of this Agreement. Amounts from this fund shall be withdrawn in accordance with Section 19.2(c).

(c) All required expenditures for renewals and replacements shall be made from the Big Rivers Station Two Renewals and Replacements Fund and the Henderson Station Two Renewals and Replacements Fund in proportion to then effective allocation of Station Two capacity between City and Big Rivers, in accordance with Section 3 of this Agreement. No expenditures shall be made from these accounts other than for renewals and replacements that would have been permitted under the Bond Ordinance.

(d) **A NEW SECTION 19.3 TO POWER SALES CONTRACT IS HEREBY CREATED AND INCLUDED AS FOLLOWS:**

19.3 Big Rivers and City agree that on or before the date on which the Station Two Bonds are retired, and the remaining balance of monies contained in the Station Two Account in the Operation and Maintenance Fund in accordance with Section 1 of the Agreement dated April 8, 1980 between Big Rivers and City shall have been disbursed, the following shall occur:

(a) Big Rivers shall establish a new Big Rivers Station Two O&M Fund and shall deposit immediately available funds in the amount of $400,000. Thereafter, Big Rivers agrees that each month it shall make levelized payments into the Big Rivers Station Two O&M Fund, not to exceed $33,300 each month, so as to restore a minimum balance of $400,000. All interest on such amounts shall be repaid to Big Rivers at the end of each calendar year, and all amounts in such fund shall be paid to Big Rivers upon termination or expiration of this Agreement. Amounts from this Fund shall be withdrawn in accordance with Section 19.3(c); and

(b) City shall establish a new Henderson Station Two O&M Fund and shall deposit immediately available funds in the amount of $100,000. Thereafter, City agrees that each month it shall make levelized payments into the Henderson Station Two O&M Fund, not to exceed $8,300, so as to restore a minimum balance of $100,000. All interest on such amounts shall be repaid to Henderson at the end of each calendar year and all amounts in such fund shall be paid to City upon termination or expiration of this Agreement. Amounts from this fund shall be withdrawn in accordance with Section 19.3(c).

(c) All required expenditures for operation and maintenance shall be made from the Big Rivers Station Two O&M Fund and the Henderson Station Two O&M Fund in proportion to the then effective allocation of Station Two capacity between City and Big Rivers, in accordance with Section 3 of this Agreement. No expenditures shall be made from these accounts other than for operation and maintenance expenses that would have been permitted to be paid as "Operating Expenses" under the Bond Ordinance.

JOINT FACILITIES AGREEMENT

4. The Joint Facilities Agreement, as heretofore amended by the May 1, 1993 Amendments, is further amended as follows:

SECTION 3.3 IS AMENDED TO READ AS FOLLOWS:

3.3 Big Rivers will allocate for the continuing joint use of the parties in the operation of their respective generating stations (Big Rivers' Green Station and City's Station Two) those Green Station FGD System Facilities described in Exhibit 1, Page 3, Part C hereto. For such use, Big Rivers shall be paid by City a prorated share of the annual carrying costs, calculated as:

$$\frac{\text{Station Two net capacity}}{\text{Station Two plus Green Station net capacities}}$$

$$\text{Currently } \frac{312 \text{ MW}}{766 \text{ MW}}$$

times the then net book value of those facilities, further multiplied by a capital carrying charge rate of 11.5 percent. Big Rivers' net book value shall be determined by taking the net book value of those facilities as of December 31, 1994, i.e. $21,675,601.32, adjusting them annually for depreciation (according to the depreciation methodology set forth in Exhibit 2), and taking into account additional costs resulting from renewals and replacements thereof. Big Rivers authorizes City to inspect Big Rivers' books to verify the original cost of these facilities, annual depreciations thereto, and the costs of any renewals and replacements thereof. All inspections by City of Big Rivers shall be at mutually agreeable times determined in advance after written request from City.

SYSTEM RESERVES AGREEMENT

5. The System Reserves Agreement of January 1, 1974 is hereby amended as follows:

SECTIONS 2.1 AND 3.1 ARE DELETED AND REPLACED BY A NEW SECTION 2.1 TO READ AS FOLLOWS:

"2.1 The City and Big Rivers covenant and agree that each will comply with any system reserve capacity requirements now required or imposed at a future date applicable to it (as such requirements may be modified from time to time and as such requirements apply to it given its respective operational characteristics) by NERC, ECAR, any successor organizations to NERC and ECAR (as applicable), any applicable regulatory or governmental agency, and any regional transmission authority, reliability council or like organization, in each case having any system reserve capacity requirements applicable to it. Absent such a requirement, neither City nor Big Rivers shall have any obligation pursuant to this Agreement to maintain system reserves. Notwithstanding the above limitations, City agrees to comply with any requirements validly imposed by any of the above entities upon Big Rivers based on Big Rivers' role as control area operator, but only if and to the extent that such requirements imposed on Big Rivers are on account of or due to the generation and/or load of the City.

6. Except as specifically modified above, the Contracts remain in full force and effect and are not altered by this Agreement.

IN TESTIMONY WHEREOF, the parties hereto have executed this Agreement in multiple counterparts as of the date first herein written.

This 15th day of July, 1998.

CITY OF HENDERSON, KENTUCKY

By: ______________________

ATTEST:
Joann Roberts

CITY OF HENDERSON UTILITY COMMISSION

By: ______________________
Chairman

ATTEST:

____

BIG RIVERS ELECTRIC CORPORATION

By: ______________________

Title: President and CEO

ATTEST:

____

Exhibit 1

BIG RIVERS - CITY OF HENDERSON
ECONOMIC DEVELOPMENT RATES

1. Big Rivers will sell power to City of Henderson according to the following rate schedule (subject to the conditions of Section 28.2 of the Agreement) per mWh:

Year 1	$20.00	
Year 2	$20.00	
Year 3	$20.00	
Year 4 (1st six months)		$20.00
Year 4 (following six months)		$21.00
Year 5	$21.00	
Year 6	$21.00	
Year 7	$21.00	
Year 8 and thereafter		to be negotiated

Year 1 shall commence on the first day of the month in which the 1998 Amendments become effective, and Year 2 and following years shall each commence on the anniversary of the first day of that month.

2. The Economic Development Rates offered by Big Rivers are for power only and are exclusive of any transmission charges Big Rivers is required to pay or charge itself to deliver this power to City on Big Rivers' transmission system. Except as otherwise provided below, Big Rivers will charge the City those transmission rates that Big Rivers is required by FERC to charge itself for delivery of such power. To the extent Big Rivers, in supplying this capacity and energy uses only transmission facilities for which City has already established transmission rights, Big Rivers will not charge an additional transmission fee. In the event Big Rivers obtains Economic Development Power from systems other than that of Big Rivers, Big Rivers shall not charge City an additional charge required to wheel such power to Big Rivers' transmission system.

Exhibit 2

JOINT FACILITIES AGREEMENT
DEPRECIATION METHODOLOGY

For purposes of Section 3.3 of the Joint Facilities Agreement and the calculation thereunder of the annual capital carrying costs for the Green Station FGD System Facilities (the "FGD Facilities"). the following depreciation methods and accounting practices shall be used:

1. Existing FGD Facilities: The FGD Facilities, as such facilities shall exist as of the date of execution of the 1998 Amendments to Contracts among the City of Henderson, Kentucky ("City"), the City of Henderson Utility Commission ("HUC") (the City and HUC being sometimes collectively referred to herein as "Henderson") and Big Rivers Electric Corporation ("Big Rivers"), shall be depreciated on a straight-line basis over an agreed useful life of 25 years, with depreciation commencing as of June 1, 1995 and expiring May 31, 2020. The net book value of those facilities as of June 1, 1995 shall be $21,675,601 for purposes of this Agreement. Notwithstanding the above described language, Big Rivers, City, and HUC agree that the above-described depreciation methodology and its effect upon payments due by any party shall be prospective only and shall have no effect relating to any payments made prior to the date of execution of the 1998 Amendments to Contracts.

2. Additions to the FGD Facilities. All additions, betterments, improvements and replacements to the FGD Facilities shall be capitalized in accordance with the prevailing Capitalization Guidelines approved by HUC and the operator of Big Rivers' Green generating station as of the date of such addition, betterment or improvement is placed in service. On the date hereof and until otherwise agreed, the "Capitalization Guidelines" shall be the capitalization guidelines attached hereto. Those additions, betterments, improvements or replacements which are capitalized under the Capitalization Guidelines (the "Capital Asset") shall, for purposes of the determination of the annual carrying costs of the FGD Facilities, be depreciated on a straight-line basis over the useful life of the Capital Asset (which useful life must be agreed upon by the parties prior to installation of the Capital Asset); provided that such useful life shall in no event exceed the useful life of the FGD Facilities as set forth in the most recently completed Depreciation Study for that facility or a Depreciation Study for the FGD Facilities which is commissioned by the Parties, upon the reasonable request of a Party, immediately following the installation of such addition, betterment, improvement or replacement.

3. Retirement from Service. If any Capital Asset that is a component of the FGD Facilities is disposed of, removed or otherwise retired from service as a consequence of the installation of a new Capital Asset, then, for purposes of the determination of the annual capital carrying costs of the FGD Facilities, the net book value of such retired asset, determined as of the date the new Capital Asset is placed in service, shall be subtracted from the net book value of the FGD Facilities as of such date.

Attached hereto is a depreciation schedule for illustration purposes only. The attached schedule illustrates the application of the depreciation methodology provided for herein to a hypothetical set of facts and is not intended to establish the actual depreciation schedule for the FGD Facilities, nor is it to be interpreted to establish the actual depreciation schedule for the FGD Facilities, nor is it to be interpreted to establish the annual capital carrying costs for the FGD Facilities allocable to Station Two.

Station 2 FGD Amortization
Depreciating Value

In-Service Date	6/8/95	
Useful Life	25 Years	
Original Cost	$	21,671,001

	1995	1996	1997	1998	1999	2000	2001	2002	2003	
Beginning Balance	$ 21,671,001	$ 21,158,817	$ 20,302,813	$ 19,435,789	$ 18,568,765	$ 17,701,741	$ 16,834,717	$ 15,967,693	$ 15,100,669	$1
Depreciation	865,764	867,024	867,024	867,024	867,024	867,024	867,024	867,024	867,024	
Net Book Value	$ 21,160,237	$ 20,302,813	$ 19,435,789	$ 18,568,765	$ 17,701,741	$ 16,834,717	$ 15,967,693	$ 15,100,669	$ 14,233,645	$1
Station 2 % of Beginning Balance (312 / 766)				$ 7,966,486	$ 7,563,237	$ 7,210,100	$ 6,856,948	$ 6,503,812	$ 6,150,664	$
Rate				11.5%	11.5%	11.5%	11.5%	11.5%	11.5%	
Reimbursement Amount				$ 918,307	$ 869,775	$ 829,162	$ 788,880	$ 747,938	$ 707,206	$

Useful Life	19.50 Years	
Capital Improvements	$	5,000,000

	1995	1996	1997	1998	1999	2000	2001	2002	2003	
Beginning Balance							$ 5,000,000	$ 4,764,637	$ 4,529,275	$
Depreciation							235,363	235,363	235,363	
Net Book Value							$ 4,764,637	$ 4,529,275	$ 4,293,912	$
Station 2 % of Beginning Balance (312 / 766)							$ 2,036,554	$ 1,932,342	$ 1,828,130	$
Rate							11.5%	11.5%	11.5%	
Reimbursement Amount							$ 234,204	$ 222,219	$ 210,231	$

Remaining Period	10.50 Years	
Retirements (RBV)	$	(2,000,000)

	1995	1996	1997	1998	1999	2000	2001	2002	2003	
Beginning Net Book Value							$ (2,000,000)	$ (1,807,855)	$ (1,615,710)	$
Depreciation Effect							(192,145)	(192,145)	(192,145)	
Net Book Value							$ (1,807,855)	$ (1,615,710)	$ (1,423,565)	$
Station 2 % of Beginning Net Book Value (312 / 766)							$ (814,621)	$ (772,017)	$ (731,402)	$
Rate							11.5%	11.5%	11.5%	
Reimbursement Effect							$ (93,661)	$ (88,807)	$ (84,112)	$

	1998	1999	2000	2001	2002	2003	
Total Reimbursement Amount	$ 918,307	$ 869,775	$ 829,162	$ 929,073	$ 881,284	$ 833,495	$

Section 2 FGD Amortization
Depreciating Value

In-Service Date [illegible]
Useful Life 25 Years
Original Cost $ 21,675,000

	2008	2009	2010	2011	2012	2013	2014	2015	2016
Beginning Balance	$ 10,765,549	$ 9,898,525	$ 9,031,501	$ 8,164,476	$ 7,297,452	$ 6,430,428	$ 5,563,404	$ 4,696,380	$ 3,829,356
Depreciation	867,024	867,024	867,024	867,024	867,024	867,024	867,024	867,024	867,024
Net Book Value	$ 9,898,525	$ 9,031,501	$ 8,164,476	$ 7,297,452	$ 6,430,428	$ 5,563,404	$ 4,696,380	$ 3,829,356	$ 2,962,332
Section 2 % of Beginning Balance (312 / 766)	$ 4,304,933	$ 4,031,775	$ 3,678,627	$ 3,325,479	$ 2,972,330	$ 2,620,182	$ 2,266,034	$ 1,915,886	$ 1,559,736
Rate	11.9%	11.9%	11.9%	11.9%	11.9%	11.9%	11.9%	11.9%	11.9%
Reimbursement Amount	$ 504,266	$ 482,484	$ 433,041	$ 392,430	$ [illegible]	$ 308,306	$ 430,306	$ [illegible]	$ 179,330

Useful Life 18.00 Years
Capital Improvements $ 4,000,000

	2008	2009	2010	2011	2012	2013	2014	2015	2016
Beginning Balance	$ 3,232,482	$ 2,053,000	$ 2,701,736	$ 2,446,774	$ 2,191,011	$ 1,935,649	$ 1,680,286	$ 1,424,923	$ 1,169,561
Depreciation	255,363	255,363	255,363	255,363	255,363	255,363	255,363	255,363	255,363
Net Book Value	$ 2,957,099	$ 2,701,736	$ 2,446,774	$ 2,191,011	$ 1,935,649	$ 1,680,286	$ 1,424,923	$ 1,169,561	$ 914,198
Section 2 % of Beginning Balance (312 / 766)	$ 1,308,470	$ 1,204,458	$ 1,100,946	$ 996,434	$ 892,422	$ 788,410	$ 684,398	$ 580,387	$ 476,375
Rate	11.9%	11.9%	11.9%	11.9%	11.9%	11.9%	11.9%	11.9%	11.9%
Reimbursement Amount	$ 150,474	$ 138,433	$ 126,001	$ 114,596	$ 102,439	$ 90,667	$ 181,333	$ 66,344	$ 54,383

Remaining Period 15.50 Years
Retirements (NBV) $ (2,000,000)

	2008	2009	2010	2011	2012	2013	2014	2015	2016
Beginning Net Book Value	$ (1,294,903)	$ (1,112,560)	$ (1,000,695)	$ (978,530)	$ (876,404)	$ (774,259)	$ (672,114)	$ (569,969)	$ (467,824)
Depreciation Effect	(102,107)	(102,145)	(102,145)	(102,145)	(102,145)	(102,145)	(102,145)	(102,145)	(102,145)
Net Book Value	$ (1,192,540)	$ (1,000,695)	$ (978,530)	$ (876,404)	$ (774,259)	$ (672,114)	$ (569,969)	$ (467,824)	$ (365,678)
Section 2 % of Beginning Net Book Value (312 / 76	$ (532,300)	$ (481,783)	$ (440,178)	$ (398,574)	$ (356,969)	$ (315,364)	$ (273,759)	$ (232,155)	$ (190,550)
Rate	11.9%	11.9%	11.9%	11.9%	11.9%	11.9%	11.9%	11.9%	11.9%
Reimbursement Effect	$ (60,159)	$ (56,406)	$ (50,431)	$ (45,806)	$ (41,051)	$ (36,267)	$ (72,335)	$ (36,690)	$ (21,915)

Total Reimbursement Amount	$ 594,951	$ 546,762	$ 498,973	$ 451,184	$ 403,395	$ 355,606	$ 755,731	$ 260,029	$ 212,240

Capitilization Guidelines

The Parties hereby agree that these Capitalization Guidelines together with the attached Company Policy Number 10 of Big Rivers, Capitalization of Expenditures, dated November 30, 1993 shall constitute the "Capitalization Guidelines" identified in Exhibit 2 to the 1998 Amendments and shall serve as the Capitalization Guidelines for the purposes of Exhibit 2. These Capitalization Guidelines (including without limitation, the attached Company Policy No. 10) may not be amended, modified or supplemented following the Execution Date without the prior written consent of each of the Parties.

The Parties agree that the attached Company Policy No. 10 of Big Rivers (which is incorporated by reference herein) shall serve to amend and supplement the RUS Uniform System of Accounts Bulletin 1767B for purposes of the Accounting Practices, and for purposes of any determination of whether an expenditure shall be a Capital Asset for the purpose of Exhibit 2.

BIG RIVERS ELECTRIC CORPORATION

COMPANY POLICY

POLICY NUMBER 10

SUBJECT **Capitalization of Expenditures**

RE-ISSUE DATE **11/30/93**

Approved by [signature]

SCOPE: Determining when to capitalize an expenditure to "Electric Plant in Service" account 101.000 as opposed to expense in accordance with REA Bulletin 181-1.

POLICY: To be capitalized, an item of property must be covered by one of the following classifications:

(A) New Retirement Unit
(B) Retirement Unit Replacement
(C) Retirement System Addition
(D) Retirement System Replacement
(E) New Minor Property Item
(F) Minor Property Item Replacement with Betterment
(G) Computer Software and Software Upgrades

RULES: See the corresponding lettered paragraph below for rules governing each case. Stated dollar values are after consideration of freight, sales tax, discount, etc.

(A) New Retirement Unit

1. Cost more than $1,000 in boiler or turbogenerator plant or $500 in other accounts, and
2. Be readily separable and separately useable, and
3. Have an expected useful life of more than one year. Valves that are requisitioned, including those inventoried, which cost more than $1,000 and are over 2" in size and are not replacements for an existing system are to be capitalized. (System valve replacements are to be charged to maintenance.)

(B) Retirement Unit Replacement

1. Cost more than $1,000 in boiler or turbogenerator plant or $500 in other accounts, and
2. Be a replacement of a similar retirement unit or consist of replacing minor property items that total to more than 50% of the existing retirement unit cost. If the 50% test is met, it is assumed a new retirement unit has been created. Retire 100% of the old unit and recapitalize the salvageable portion along with the new minor property item(s). (The replacement of existing minor property items costing 50% or less of the original retirement unit is to be charged to maintenance.)

(C) Retirement System Addition

1. Be an addition to or an expansion of a system, and
2. Cost more than $1,000 in boiler or turbogenerator plant or $500 in other accounts, and
3. Be of permanent nature, and
4. Be an integral part of an existing system. (A system is a grouping of generic or interacting items forming a unified whole. Classification as a system is for accounting convenience and enables an efficient and methodical means to account for a grouping of items which are frequently changing as a result of additions and replacements. Classification as a system may be appropriate where specific item identity is difficult to ascertain. Financial Services will make all system determinations. When it is evident that multiple items are purchased on multiple requisitions, possibly on different dates, for the same system project, the capitalization decision shall be based on the total project cost.)

(D) Retirement System Replacement

1. Be an integral part of an existing system, and
2. Be of permanent nature, and
3. Cost more than 50% of the existing retirement system. If the 50% test is met, it is assumed a new retirement system has been created. Retire 100% of the old system and recapitalize the salvageable portion along with the new replacement cost. (Replacement of an existing system costing 50% or less of the original system is to be charged to maintenance.)

(E) New Minor Property Item

1. Minor Property item not previously existing, and
2. Be of a permanent nature, and
3. Cost exceeds 25% of the retirement unit of which it will become a part or $10,000, the smaller of the two. (Otherwise, the addition of minor property items is to be charged to operations.)

(F) Minor Property Item Replacement with Betterment

1. Be of a permanent nature, and
2. Result in a substantial betterment with the primary aim of making the property affected more useful, more efficient, more durable, or capable of greater capacity. Capitalize the cost in accordance with the NOTE 1, below.

(G) Computer Software and Software Upgrades

1. Capitalize any new software purchase of $1,000 or more if used with a boiler or turbogenerator computer or $500 or more if used for any other computer, as long as the new software has a useful life of more than one year.

2. Any software upgrade should be capitalized if the cost of the upgrade exceeds 25% of the software which it will become a part or $10,000, the smaller of the two. The 25% must be $1,000 or more if used with a boiler or turbogenerator computer or $500 or more if used for any other computer. The software upgrade must have a life of more than one year.

NOTE 1: In all cases above except (E), the amount capitalized is governed by standard accounting principles. For (E) above, the amount capitalized is equal to the difference between the cost of the new minor property item and the cost of replacement without betterment at today's prices. The remaining dollars are to be charged to maintenance.

NOTE 2: A work order is required when constructing, fabricating, modifying, installing, or removing capital facilities or equipment. See Estimate Construction Work Order procedure number 011.210.08 for details.

REFERENCES: Excerpts taken from REA Bulletin 181-1 (Page 101-13) and 181-2 (Page 1.)

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

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-__________**

DIRECT TESTIMONY

OF

ROBERT W. BERRY
PRESIDENT AND CHIEF EXECUTIVE OFFICER

ON BEHALF OF

BIG RIVERS ELECTRIC CORPORATION

FILED: May 1, 2018

DIRECT TESTIMONY

OF

ROBERT W. BERRY

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DIRECT TESTIMONY

OF

ROBERT W. BERRY

I. <u>INTRODUCTION</u>

Q. Please state your name, business address, and position.

A. My name is Robert W. Berry. I am employed by Big Rivers Electric Corporation ("Big Rivers"), 201 Third Street, Henderson, Kentucky 42420 as its President and Chief Executive Officer. I have held this position since July 1, 2014.

Q. What is your experience in the electric utility industry prior to assuming the position of President and Chief Executive Officer for Big Rivers?

A. Previously, I was Big Rivers' Chief Operating Officer beginning February 2013. Before that, I served as Big Rivers' Vice President of Production from the closing of the transaction that unwound Big Rivers' 1998 lease with E.ON U.S., LLC and its affiliates (the "Unwind Transaction"), described in Case No. 2007-00455. Before the closing of the Unwind Transaction, I was employed by Western Kentucky Energy Corporation ("WKE") for 11 years beginning as a Maintenance Manager in 1998. I held the position of Plant Manager at the Coleman Generating Station from 2000 until 2003, at which time I became the Plant Manager of the Sebree Generating Station. Altogether, I have over 37 years of experience in this system, having worked for both Big Rivers and WKE since 1981.

Q. Have you previously testified before the Kentucky Public Service Commission ("Commission")?

A. Yes. I testified most recently on behalf of Big Rivers in Case No. 2016-00278, in which Big Rivers sought and obtained an order from the Commission declaring that Big Rivers was not responsible for the variable costs of any "Excess Henderson Energy" that Big Rivers declined to take. I also testified in two cases seeking approval of contracts relating to the two smelters owned by subsidiaries of Century Aluminum Company, Case Nos. 2013-00221 and 2013-00413; in Big Rivers' last two general rate cases, Case Nos. 2012-000535 and 2013-00199; and in Big Rivers' 2012 Environmental Compliance Plan case, Case No. 2012-00063.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain Big Rivers' analysis confirming the termination of certain contracts between Big Rivers and the City of Henderson, Kentucky and City of Henderson Utility Commission d/b/a Henderson Municipal Power & Light ("HMP&L") (collectively, "Henderson"), as well as the relief Big Rivers is requesting in this proceeding.

Q. Are you sponsoring any exhibits?

A. Yes. I have prepared the following exhibits to support my testimony:

Exhibit Berry-1 – Key Financial Metric Differences Between Base Case Long-Term Financial Plan And Station Two Exit Sensitivity

Exhibit Berry-2 – Supporting Workpapers

Exhibit Berry-3 – Henderson's Integrated Resource Plan Report dated April 19, 2018

Exhibit Berry-4 – Email from Chris Heimgartner dated February 27, 2018

III. THE STATION TWO CONTRACTS

Q. Provide a brief overview of Big Rivers' contractual relationship with Henderson.

A. Henderson owns two coal-fired electric generating units near Sebree, Kentucky known as "Station Two," which have a Total Capacity of 312 MW. Big Rivers has operated and maintained the Station Two units under a series of contracts that were originally executed on August 1, 1970 (the "Station Two Contracts"), and that have since been amended on several occasions. The Station Two Contracts are subject to the jurisdiction of this Commission.

IV. ALL BUT ONE OF THE STATION TWO CONTRACTS HAVE TERMINATED

Q. Please describe why all but one of the Station Two Contracts have terminated.

A. The Station Two Contracts were amended in 1993 (the "1993 Amendments") to give Big Rivers the option to extend the term of the contracts "to continue for so long as [either of the Station Two units] is operated, or is capable of normal, continuous, reliable operation for the economically competitive production of electricity, temporary outages excepted."[1] Subsequently, Big Rivers elected to exercise that option. The Station Two Contracts were again amended in 1998 (the "1998 Amendments"), and Section 1 of those 1998 Amendments, which incorporates Big Rivers' election to extend the contract term provides:

[1] 1993 Amendments § 1.1.

> The terms of all [of the Station Two Contracts] except the Joint Facilities Agreement shall be extended for the operating life of Station Two, the operating life of which shall be considered to continue for so long as Unit 1 and Unit 2, or either of them, is operated, or is capable of normal, continuous, reliable operation for the economically competitive production of electricity, temporary outages excepted.

Thus, both parties to the contracts recognized that at some point, Station Two would no longer be capable of producing economically competitive energy, and that the contracts would terminate at that point in time.

Utilizing its own employees who are highly experienced and knowledgeable concerning the operation and economics of Station Two, Big Rivers analyzed the economic viability of the Station Two units and confirmed that the Station Two units were no longer capable of normal, continuous, reliable operation for the economically competitive production of electricity. Big Rivers' analysis included a sensitivity Big Rivers evaluated as part of its 15-year long-term financial plan (2017-2031), which was presented to its Board of Directors at the Board's December 2017 meeting. At the time when inputs were developed for the long-term financial plan, Big Rivers was evaluating options and was in negotiations with Henderson over issues arising out of the Station Two Contracts. Due to those on-going negotiations, the base case forecast assumes the continuation of the Station Two Contracts; however, a sensitivity was evaluated where Big Rivers exited the Station Two Contracts. The Station Two Contracts exit sensitivity is discussed below.

Big Rivers' 15-year long-term financial plan (2017-2031) had projected two base rate increases ([redacted]). The Station Two Exit sensitivity left these base rate increases unchanged so the impact to Big Rivers' financial metrics could be compared. The base case also assumed Henderson keeping all the

Station Two excess generation at its allocation amount (currently 115 MW) while being responsible for the variable costs of this excess generation. The Station Two exit sensitivity included the following changes from the base case:

- Big Rivers exits the Station Two Contracts in January 2019.
- Big Rivers' share of Station Two energy was removed in January 2019.
- Big Rivers' share of Station Two capacity was removed for PY 18/19 (June 2018 – May 2019).
- Station Two O&M and capital costs were removed.
- Station Two depreciation, property tax, property insurance and State of Kentucky emission fees were removed in 2019.
- Big Rivers' share of Station Two projected Environmental Compliance Plan costs were removed with the exception of keeping the [redacted] expense for ash pond closures in the forecast.
- Big Rivers' share of Station Two SO_2 and NO_X allocations were removed
- Big Rivers assumed a regulatory asset was established for the projected remaining book value of Station Two ($91M). It was amortized over 15 years with recovery beginning in 2021.

A comparison of the key financial metrics for the base case and the Station Two Contracts exit case show that all the key metrics were favorable for the Station Two exit. The net margins for the period were [redacted] favorable. Cash balance at the end of the period was [redacted] favorable. The TIER annual difference averaged [redacted] favorable. The differences in the key financial metrics are shown on Exhibit Berry-1. Exhibit Berry-2 contains the supporting workpapers used in the development of Exhibit Berry-1.

The Big Rivers analysis described above compared the costs of operating Station Two to the revenue Big Rivers would receive in the Midcontinent Independent System Operator, Inc. ("MISO") market[2] from its share of the power generated by Station Two over the 15-year period covered by the long-term financial forecast. The results of that analysis show that the cost of producing power from Station Two exceeds the potential market revenues from that power. Thus, based on its analysis, Big Rivers concluded that the Station Two units were no longer capable of normal, continuous, reliable operation for the economically competitive production of electricity.

Q. Has Big Rivers had a third party validate the results of its analysis?

A. Yes. Big Rivers retained The Brattle Group, Inc. ("Brattle") to perform an independent analysis of the economic viability of the Station Two units. Brattle's analysis is described in the Direct Testimony of Metin Celebi attached as Exhibit 5 to Big Rivers' Notice and Application and confirms Big Rivers' analysis. As Mr. Celebi explains, Brattle compared Station Two's projected costs as a whole against its projected energy and capacity revenues under several market outlooks, such as a range of energy, capacity, and fuel prices, over the period from 2019 through 2035. Brattle's study shows that in each and every year of the study period, and under every scenario that was evaluated, the resulting margins from Station Two are negative and that every year that retirement of Station Two is delayed results in a greater financial loss. Thus, like Big Rivers, Brattle

[2] Big Rivers has offered Station Two's energy into the MISO energy market since Big Rivers integrated into MISO on December 1, 2010. Big Rivers has offered Station Two's capacity into the MISO capacity market since MISO's first capacity auction for the 2013-14 planning year. As Big Rivers explained in its MISO update filed with the Commission on September 29, 2017, in P.S.C. Case No. 20010-00043, remaining in MISO is the most viable way for Big Rivers to satisfy is NERC Contingency Reserve obligations and joining PJM or another regional transmission operator are not viable options at this time. Thus, Big Rivers currently has no plans to operate Station Two in a market other than in the MISO wholesale markets.

determined that the Station Two units are no longer capable of normal continuous, reliable operation for the economically competitive production of electricity.

Q. What did Big Rivers do upon receiving the results of Brattle's analysis?

A. After evaluating both its own analysis as well as Brattle's analysis confirming, Big Rivers prepared a notice to Henderson, which Big Rivers is delivering to Henderson on the date that Big Rivers' Notice and Application will be filed with the Commission, notifying Henderson that because the Station Two units are no longer capable of normal continuous, reliable operation for the economically competitive production of electricity, all of the Station Two Contracts, except the Joint Facilities Agreement (the "Terminated Contracts"), have terminated pursuant to Section 1 of the 1998 Amendments. Big Rivers' notice to Henderson is attached as Exhibit 1 to Big Rivers' Notice and Application.

Q. Is Big Rivers aware of any other studies regarding the economic viability of Station Two?

A. Yes. Henderson recently retained GDS Associates, Inc. ("GDS") to prepare an Integrated Resource Plan ("IRP") on its behalf, principally to determine, as GDS noted in the introduction to its IRP Report, "whether [Henderson] should continue to invest and maintain [Station Two] or if [it] should consider retiring [Station Two] and moving forward with another power supply arrangement." On page 34 of its report, GDS summarized its key finding:

> Because the IRP evaluation has multiple resource scenarios that result in a lower overall power cost than the [business as usual ("BAU")] scenario in every sensitivity of the IRP, coupled with the fact that a key assumption for the BAU scenario (and the other two scenarios where [Henderson] had continued [Station Two] ownership) did not include any normal or major

> capital investments beyond 2023, the conclusion of this study is that [Henderson] should divest itself of [Station Two]."

Henderson publicly released GDS' IRP Report on April 25, 2018. A copy of that report is attached hereto as Exhibit Berry-3.

Q. Is Big Rivers' termination notice subject to any approvals?

A. The Commission has already approved the Station Two Contracts and the amendments to those contracts, including Section 1 of the 1998 Amendments. As such, Big Rivers does not believe any further authority is required from the Commission for the termination of the Terminated Contracts to be effective. However, as described below, Big Rivers is requesting findings from the Commission (i) supporting Big Rivers' determination that the Station Two units are no longer capable of normal, continuous, reliable operation for the economically competitive production of electricity; (ii) authorizing Big Rivers to continue to operate Station Two to allow Henderson time to make alternate arrangements for Station Two and for Henderson's power supply needs, if Henderson desires that Big Rivers do so; and (iii) authorizing Big Rivers to establish a regulatory account to defer the expenses Big Rivers will incur as a result of the termination of the Terminated Contracts.

Additionally, Big Rivers notified RUS of the contract termination and requested its authority to establish a regulatory account relating to the contract termination. RUS's letters stating that it has no objection to the contract termination and authorizing Big Rivers to establish a regulatory account are attached to Big Rivers' Notice and Application as Exhibit 6.

Q. Why is Big Rivers requesting a finding from the Commission that the Station Two units are no longer capable of normal, continuous, reliable operation for the economically competitive production of electricity?

A. Because the Commission has jurisdiction over the Station Two Contracts, and has specifically exercised that jurisdiction in the past by approving the contracts and their amendments, Big Rivers felt that the Commission should be notified that the Terminated Contracts have terminated. Also, since Henderson has raised an issue by indicating that it would "push back" on any attempt by Big Rivers to exit the contracts, Big Rivers is asking for a finding from the Commission supporting Big Rivers' determination that the Station Two units are no longer capable of normal, continuous, reliable operation for the economically competitive production of electricity to resolve that dispute.

Q. Why is Big Rivers requesting that the Commission authorize Big Rivers to continue to operate Station Two until May 31, 2019?

A. Big Rivers believes it is reasonable to give Henderson time to make arrangements for Station Two and for its power supply. Big Rivers believes 13 months from the date Big Rivers provided Henderson notice of the termination is a reasonable amount of time to give Henderson to make these arrangements, especially in light of the fact that Big Rivers will continue to lose money on the Station Two Contracts during that time.

Q. What alternate arrangements can Henderson make with regard to the operation of Station Two?

A. Henderson could shut down the Station Two units, operate the units itself (using current or different personnel), or find a replacement operator.

Q. What alternate arrangements can Henderson make with regard to its power supply?

A. If Henderson is unable or unwilling to find a substitute operator for the Station Two units, Henderson nevertheless has options to find an economically competitive and reliable supply of power. These options include entering into bilateral contracts with power suppliers, such as Big Rivers; and making appropriate arrangements to purchase power from a regional transmission operator such as MISO. Either of these options would give Henderson a reliable power supply that is more economic and efficient than continuing to operate the Station Two units.

Q. Why is the Joint Facilities Agreement not terminating?

A. The Joint Facilities Agreement governs the facilities that are owned by either Big Rivers or Henderson and that are used for both the Station Two units and Big Rivers' Green and/or Reid units. The termination provision of Section 1 of the 1998 Amendments was not made applicable to the Joint Facilities Agreement because the joint facilities will continue to be utilized after the termination of the other Station Two Contracts. For example, if Henderson decides to continue operating the Station Two units after May 31, 2019, it will need to utilize the joint facilities. Big Rivers will also utilize the joint facilities under the Joint Facilities Agreement to operate its units at the Sebree site after May 31, 2019.

Q. Has Big Rivers completed any other analyses of the economic viability of Station Two?

A. Yes. In addition to the sensitivity to the Big Rivers long-term financial plan described above, Big Rivers filed its 2017 Integrated Resource Plan (the "2017 IRP") with the

Commission on September 21, 2017, in Case No. 2017-00384. The 2017 IRP is a road map for how Big Rivers will meet its projected power requirements through 2031 based on modeling a base case set of assumptions and sensitivities around those assumptions. The modeling produces a resource plan that provides an adequate and reliable supply of electricity to meet forecasted electricity requirements at the lowest possible cost. Modeling the base case assumptions, which include the assumption that the Station Two Contracts cannot terminate prior to 2020, resulted in a resource plan where the Station Two Contracts terminate in 2020 with no changes to the operation of the Big Rivers-owned units and with no new generation resources being built. Big Rivers ran a sensitivity that allowed the Station Two Contracts to terminate in 2018, and the least-cost resource plan under that sensitivity analysis has the Station Two Contracts terminating in 2018. In fact, in all but two of the scenarios Big Rivers modeled, the least-cost resource plan is for the Station Two Contracts to terminate as soon as possible. The only scenarios under which the Station Two Contracts are not terminated are the scenario that assumes market energy prices are twenty percent higher than the base case projections and the scenario that assumes coal prices are twenty percent lower than the base case projections.

Q. Can Big Rivers take actions to make efficiency improvements to the Station Two units to make them economically competitive?

A. No. Big Rivers has begun to dispatch the Station Two units in MISO on an economic commit basis, so they only operate when it makes economic sense to do so, or they are needed for reliability. The net capacity factor of the units for 2018 (through the end of March) is approximately 7.5% for Unit 1 and 13.5% for Unit 2, which includes hours that the units were run for environmental testing.

Big Rivers, through its diligence and continued testing, has also been able to reduce the minimum generation levels of the Station Two units to approximately 56 MW for each unit. In addition to these changes, the prevailing wage laws changed in 2017 thereby enabling the Parties to lower labor costs associated with certain contracted labor associated with Station Two. Moreover, the Parties agreed to revise the fuel box in order to allow them to burn a lower chlorine fuel in Station Two which is currently able to be purchased at a lower cost. Notwithstanding all of these changes, Station Two is still unable to generate economically competitive electricity.

Q. **Would the Station Two units be economically competitive if they were converted to natural gas?**

A. No. Big Rivers' 2017 IRP modeled converting Station Two to natural gas. Under the base case and all of the sensitivities Big Rivers modeled, converting Station Two to natural gas was never found to be economically viable.

Q. **If Station Two energy is not economically competitive, why does Henderson continue to want Station Two to operate?**

A. Over the past several years, Big Rivers has had numerous discussions with Henderson about this issue, and Big Rivers has recommended various alternatives to Henderson to modify the operations of Station Two to make Station Two more competitive and lower the cost of serving the load of Henderson. Until recently, when Big Rivers began dispatching the Station Two units in MISO on an economic commit basis with no objection from Henderson, Henderson rejected Big Rivers' recommendations and required Big Rivers to operate both units of Station Two on a continuous basis. It is my understanding that Henderson's position is based on its belief that having the Station Two units in continuous operation provides reliability benefits, although I do not agree that position is a reasonable one.

Q. Why do you think Henderson's position is not reasonable?

A. Henderson's position is unreasonable because the units are no longer capable of normal, continuous, reliable operation for the economically competitive production of electricity. There are many other reasonable options available for Henderson to serve its 115 MW load at a lower cost rather than operating a power plant. The MISO market has sufficient reserves to meet Henderson's load demands, and power can be procured from the market with liquidated damages terms to provide financial protection. Ultimately, since the Station Two units are owned by Henderson, Henderson will decide when to retire the units or idle them. But the Station Two Contracts protect Big Rivers by terminating Big Rivers' obligations to operate the units and take and pay for power from the units when the units are no longer capable of normal, continuous, reliable operation for the economically competitive production of electricity.

V. BIG RIVERS' REQUESTS FOR RELIEF

Q. Is there a dispute between Big Rivers and Henderson over the termination of the Terminated Contracts?

A. Yes. I have had several discussions with the City regarding the economic viability of Station Two, the fact that both parties continue to lose money as a result of Henderson's continuing insistence that Big Rivers operate one or both of the units, and various Big Rivers proposals to limit those losses. These conversations have made it evident that Henderson is unwilling to work with Big Rivers to find an agreeable and viable solution for the future of Station Two. Additionally, on February 12, 2018, I had a conversation with Chris Heimgartner, HMP&L's General Manager, and on March 28, 2018, I had a conversation with Steve Austin, the Mayor of the City of Henderson, to inform them that Big Rivers had determined that the Station Two units were no longer capable of normal, continuous, reliable operation for the economically competitive production of electricity. In response, Mr. Heimgartner stated that Henderson would "push back" on any attempt by Big Rivers to exit the Station Two Contracts. Mr. Heimgartner also sent me the email attached hereto as Exhibit Berry-4 further indicating that Henderson would dispute any attempt by Big Rivers to exit the contracts.

Q. What is Big Rivers requesting the Commission to do in this proceeding?

A. As explained in the Notice and Application, Big Rivers is requesting that the Commission resolve the dispute between Big Rivers and Henderson by confirming Big Rivers' determination that the Station Two units are no longer capable of normal, continuous, reliable operation for the economically competitive production of electricity, and that the Station Two Contracts, except for the Joint Facilities Agreement, as amended, have therefore expired and terminated as of May 1, 2018, pursuant to Section 1 of the 1998 Amendments. Big Rivers is further requesting that the Commission authorize Big Rivers to continue to operate Station Two until up to May 31, 2019, to give Henderson time to make alternate arrangements for the operation of Station Two and for Henderson's power supply needs, if Henderson desires that Big Rivers do so. And, as noted above, Big Rivers is requesting that the Commission grant it the authority to establish a regulatory asset to defer the expenses Big Rivers will incur as a result of the termination of the Terminated Contracts.

Q. Why is Big Rivers requesting expedited treatment of this matter?

A. Big Rivers is requesting that the Commission issue an order no later than August 31, 2018, to allow time for Henderson to make any alternate arrangements prior to May 31, 2019, and for Big Rivers to accomplish the tasks required of it to cease operating Station Two.

VI. CONCLUSION

Q. Do you have any closing comments?

A. Yes. Section 1 of the 1998 Amendments reasonably contemplates that the Station Two Contracts, except the Joint Facilities Agreement, will terminate if the Station Two units are no longer capable of normal, continuous, reliable operation for the economically competitive production of electricity. The Station Two units have provided benefits to both Big Rivers and Henderson in the past, but as Big Rivers and Brattle have demonstrated, the units have outlived their ability to generate economically competitive power. Now that the units have become uneconomic, it is no longer reasonable to continue to operate them, and Big Rivers' prudent decision to take the steps necessary to determine that the Terminated Contracts have terminated and to notify Henderson that the contracts have terminated will protect itself, its Members, and the Members' retail ratepayers from any unnecessary costs in the event Henderson nevertheless decides to continue to operate Station Two.

Q. Does this conclude your testimony?

A. Yes.

BIG RIVERS ELECTRIC CORPORATION

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. 2018-00_____

VERIFICATION

I, Robert W. (Bob) Berry, President and Chief Executive Officer for Big Rivers Electric Corporation, verify, state, and affirm that I prepared or supervised the preparation of my Direct Testimony filed with this Verification, and that Direct Testimony is true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Robert W. Berry

Robert W. (Bob) Berry

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Robert W. (Bob) Berry on this the 30 th day of April, 2018.

Paula Mitchell

Notary Public, Kentucky At Large

My Commission Expires 1-12-21

Big Rivers Electric Corporation
Key Financial Metric Differences between Base Case Long-Term Financial Plan and Station Two Exit Sensitivity
Case No. 2018-00______

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Net Margins ($ Millions) - HMPL Exit	[redacted]													
Net Margins ($ Millions) - Current Budget	[redacted]													
Capital ($ Millions) - HMPL Exit	[redacted]													
Capital ($ Millions) - Current Budget	[redacted]													
TIER - HMPL Exit	[redacted]													
TIER - Current Budget	[redacted]													
North Star - HMPL Exit	[redacted]													
North Star - Current Budget	[redacted]													
Ending Cash Balance (In Millions $) - HMPL Exit	[redacted]													
Ending Cash Balance (In Millions $) - Current Budget	[redacted]													
Debt Service Coverage Ratio - HMPL Exit	[redacted]													
Debt Service Coverage Ratio - Current Budget	[redacted]													

Big Rivers Electric Corporation
Key Financial Metric Differences between Base Case Long-Term Financial Plan and Station Two Exit Sensitivity
Case No. 2018-00_____

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Non-Member/Market Revenue ($ millions) - HMPL Exit	[redacted]													
Non-Member/Market Revenue ($ millions) - Current Budget														
Wholesale Rural Base Rate $/MWh - HMPL Exit														
Wholesale Rural Base Rate $/MWh - Current Budget														
Wholesale Rural Rate "All-In" (Net) $/MWh - HMPL Exit														
Wholesale Rural Rate "All-In" (Net) $/MWh - Current Budget														
Wholesale Large Industrial Base Rate $/MWh - HMPL Exit														
Wholesale Large Industrial Base Rate $/MWh - Current Budget														
Wholesale Large Industrial Rate "All-In" (Net) $/MWh - HMPL Exit														
Wholesale Large Industrial Rate "All-In" (Net) $/MWh - Current Budget														

Exhibit Berry-2 – Workpapers

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. 2018-000______

CONFIDENTIAL RESPONSE

Exhibit Berry-2 Workpaper Files:

2017-31 PCM NewFormat Budget-18-17 Price wo C-WG MR-HMPL Exit 2019 (no links).xlsx
Financial Forecast (2018-2031) 11-21-2017 HMPL Exit.xlsx

FILED: May 1, 2018

INFORMATION SUBMITTED UNDER PETITION FOR CONFIDENTIAL TREATMENT

Big Rivers Electric Corporation
Capacity Forecast 2018 Budget (10-20-17) HMPL Exit
Case No. 2018-00_____

PRMR (Planning Reserve Margin Requirements)									
									Big Rivers
PY	Native	New Load	New Load	HMP&L	Domtar	NCP	NCP to CP Factor	CP	Losses, %
13-14								1,583.0	1.3%
14-15								1,084.2	1.3%
15-16	651	0	0	109	0	760	95.13%	723.0	1.5%
16-17	682	9	0	109	50	850	95.76%	814.0	1.6%
17-18	[redacted]								
18-19									
19-20									
20-21									
21-22									
22-23									
23-24									
24-25									
25-26									
26-27									
27-28									
28-29									
29-30									
30-31									
31-32									

Sheet Name - Base Case

Big Rivers Electric Corporation
Capacity Forecast 2018 Budget (10-20-17) HMPL Exit
Case No. 2018-00_____

								N
PY	CP w/Loss	PRM, %	PRMR	HMP&L CP	HMP&L CP with Losses	HMP&L PRMR	Big Rivers UCAP	Nebraska Sale
13-14	1,603.6	6.2%	1,703.0				1,846.5	
14-15	1,098.3	7.3%	1,178.5				1,809.6	
15-16	733.8	7.1%	785.9	103.7	105.2	112.7	1,389.8	
16-17	827.0	7.6%	889.9	104.4	106.1	114.1	1,379.4	
17-18	[redacted]							
18-19	[redacted]							
19-20	[redacted]							
20-21	[redacted]							
21-22	[redacted]							
22-23	[redacted]							
23-24	[redacted]							
24-25	[redacted]							
25-26	[redacted]							
26-27	[redacted]							
27-28	[redacted]							
28-29	[redacted]							
29-30	[redacted]							
30-31	[redacted]							
31-32	[redacted]							

Big Rivers Electric Corporation
Capacity Forecast 2018 Budget (10-20-17) HMPL Exit
Case No. 2018-00_____

n Member Capacity Transactions				MISO Capacity	Capacity Price Forecast, $/MW-Day			MISO Actual Capacity Prices
PY	Nebraska Purchase @ SPP	Kentucky Municipals	New Sale		2018 Budget	2017 Budget	2016 Budget	
13-14				143.5				
14-15				631.1				
15-16				603.9				$ 3.48
16-17				489.5			$ 49.32	$ 72.00
17-18	[redacted]							
18-19	[redacted]							
19-20	[redacted]							
20-21	[redacted]							
21-22	[redacted]							
22-23	[redacted]							
23-24	[redacted]							
24-25	[redacted]							
25-26	[redacted]							
26-27	[redacted]							
27-28	[redacted]							
28-29	[redacted]							
29-30	[redacted]							
30-31	[redacted]							
31-32	[redacted]							

Big Rivers Electric Corporation
Capacity Forecast 2018 Budget (10-20-17) HMPL Exit
Case No. 2018-00_____

Year	Total Capacity		Capacity Sold (Hedged)						
			Jan-May			Jun-Dec			
	Jan-May	Jun-Dec	MW	$/MW-day	$	MW	$/MW-day	$	MW
2018	[redacted]								
2019	[redacted]								
2020	[redacted]								
2021	[redacted]								
2022	[redacted]								
2023	[redacted]								
2024	[redacted]								
2025	[redacted]								
2026	[redacted]								
2027	[redacted]								
2028	[redacted]								
2029	[redacted]								
2030	[redacted]								
2031	[redacted]								

Sheet Name - Base Case

Big Rivers Electric Corporation
Capacity Forecast 2018 Budget (10-20-17) HMPL Exit
Case No. 2018-00_____

Year	Capacity Forecast					Capacity Revenue, $		
	Jan-May		Jun-Dec					
	$/MW-day	$	MW	$/MW-day	$	Hedged	Forecast	Total
2018	[redacted]							
2019	[redacted]							
2020	[redacted]							
2021	[redacted]							
2022	[redacted]							
2023	[redacted]							
2024	[redacted]							
2025	[redacted]							
2026	[redacted]							
2027	[redacted]							
2028	[redacted]							
2029	[redacted]							
2030	[redacted]							
2031	[redacted]							

Sheet Name - Base Case

Year
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Big Rivers Electric Corporation
Capacity Forecast 2018 Budget (10-20-17) HMPL Exit
Case No. 2018-00_____

						PRMR (Planning Reserve Margin Requirements)			
						Big Rivers			
PY	Native	New Load	New Load	HMP&L	Domtar	NCP	NCP to CP Factor	CP	Losses, %
13-14								1,583.0	1.3%
14-15								1,084.2	1.3%
15-16	651	0	0	109	0	760	95.13%	723.0	1.5%
16-17	682	9	0	109	50	850	95.76%	814.0	1.6%
17-18	[redacted]								
18-19									
19-20									
20-21									
21-22									
22-23									
23-24									
24-25									
25-26									
26-27									
27-28									
28-29									
29-30									
30-31									
31-32									

Sheet Name - Base Case (without HMPL)

Big Rivers Electric Corporation
Capacity Forecast 2018 Budget (10-20-17) HMPL Exit
Case No. 2018-00_____

PY	CP w/Loss	PRM, %	PRMR	HMP&L CP	HMP&L CP with Losses	HMP&L PRMR	Big Rivers UCAP	N Nebraska Sale
13-14	1,603.6	6.2%	1,703.0				1,846.5	
14-15	1,098.3	7.3%	1,178.5				1,809.6	
15-16	733.8	7.1%	785.9	103.7	105.2	112.7	1,389.8	
16-17	827.0	7.6%	889.9	104.4	106.1	114.1	1,379.4	
17-18	[redacted]							
18-19	[redacted]							
19-20	[redacted]							
20-21	[redacted]							
21-22	[redacted]							
22-23	[redacted]							
23-24	[redacted]							
24-25	[redacted]							
25-26	[redacted]							
26-27	[redacted]							
27-28	[redacted]							
28-29	[redacted]							
29-30	[redacted]							
30-31	[redacted]							
31-32	[redacted]							

Sheet Name - Base Case (without HMPL)

Big Rivers Electric Corporation
Capacity Forecast 2018 Budget (10-20-17) HMPL Exit
Case No. 2018-00______

…on Member Capacity Transactions				MISO Capacity	Capacity Price Forecast, $/MW-Day			MISO Actual Capacity Prices
PY	Nebraska Purchase @ SPP	Kentucky Municipals	New Sale		2018 Budget	2017 Budget	2016 Budget	
13-14				143.5				
14-15				631.1				
15-16				603.9				$ 3.48
16-17				489.5			$ 49.32	$ 72.00
17-18	[redacted]							
18-19	[redacted]							
19-20	[redacted]							
20-21	[redacted]							
21-22	[redacted]							
22-23	[redacted]							
23-24	[redacted]							
24-25	[redacted]							
25-26	[redacted]							
26-27	[redacted]							
27-28	[redacted]							
28-29	[redacted]							
29-30	[redacted]							
30-31	[redacted]							
31-32	[redacted]							

Sheet Name - Base Case (without HMPL)

Big Rivers Electric Corporation
Capacity Forecast 2018 Budget (10-20-17) HMPL Exit
Case No. 2018-00_____

Year	Total Capacity		Capacity Sold (Hedged)						
			Jan-May			Jun-Dec			
	Jan-May	Jun-Dec	MW	$/MW-day	$	MW	$/MW-day	$	MW
2018	[redacted]								
2019									
2020									
2021									
2022									
2023									
2024									
2025									
2026									
2027									
2028									
2029									
2030									
2031									

Sheet Name - Base Case (without HMPL)

Big Rivers Electric Corporation
Capacity Forecast 2018 Budget (10-20-17) HMPL Exit
Case No. 2018-00_____

Year	Capacity Forecast					Capacity Revenue, $		
	Jan-May		Jun-Dec					
	$/MW-day	$	MW	$/MW-day	$	Hedged	Forecast	Total
2018	[redacted]							
2019								
2020								
2021								
2022								
2023								
2024								
2025								
2026								
2027								
2028								
2029								
2030								
2031								

Sheet Name - Base Case (without HMPL)

Big Rivers Electric Corporation
Capacity Forecast 2018 Budget (10-20-17) HMPL Exit
Case No. 2018-00______

Year
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Sheet Name - Base Case (without HMPL)

Big Rivers Electric Corporation
Capacity Forecast 2018 Budget (10-20-17) HMPL Exit
Case No. 2018-00_____

	Annual EFOR$_d$ for Units (September 1 to August 31)								
Unit	9/1/12 to 8/31/13	9/1/13 to 8/31/14	9/1/14 to 8/31/15	9/1/15 to 8/31/16	9/1/16 to 8/31/17	9/1/17 to 8/31/18	9/1/18 to 8/31/19	9/1/19 to 8/31/20	9/1/20 to 8/31/21
Wilson	5.48%	6.07%	1.46%	4.73%	14.00%	[redacted]	[redacted]	[redacted]	[redacted]
Green 1	2.63%	7.98%	2.58%	6.02%	6.00%	[redacted]	[redacted]	[redacted]	[redacted]
Green 2	1.52%	0.94%	4.77%	1.98%	2.98%	[redacted]	[redacted]	[redacted]	[redacted]
HMP&L 1	6.37%	2.82%	4.62%	13.57%	15.54%	[redacted]	[redacted]	[redacted]	[redacted]
HMP&L 2	6.31%	4.46%	17.55%	33.74%	11.70%	[redacted]	[redacted]	[redacted]	[redacted]
Reid CT	17.56%	13.15%	29.63%	80.68%	19.07%	[redacted]	[redacted]	[redacted]	[redacted]
SEPA-BR					0.00%	[redacted]	[redacted]	[redacted]	[redacted]
SEPA-HMP&L					0.00%	[redacted]	[redacted]	[redacted]	[redacted]

	3 Year EFOR$_d$ for Units (September 1 to August 31)								
Unit	PY 15-16	PY 16-17	PY 17-18	PY 18-19	PY 19-20	PY 20-21	PY 21-22	PY 22-23	PY 23-24
	9/1/11 to 8/31/14	9/1/12 to 8/31/15	9/1/13 to 8/31/16	9/1/14 to 8/31/17	9/1/15 to 8/31/18	9/1/16 to 8/31/19	9/1/17 to 8/31/20	9/1/18 to 8/31/21	9/1/19 to 8/31/22
Wilson	4.73%	4.21%	3.95%	6.73%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Green 1	3.71%	4.24%	5.36%	4.87%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Green 2	1.48%	2.30%	2.45%	3.24%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
HMP&L 1	4.71%	4.63%	6.69%	11.24%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
HMP&L 2	5.60%	9.21%	18.60%	21.00%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Reid CT	14.41%	20.44%	43.46%	43.13%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SEPA-BR	0.00%	0.00%	4.61%	0.00%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SEPA-HMP&L	0.00%	0.00%	4.61%	0.00%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Big Rivers Electric Corporation
Capacity Forecast 2018 Budget (10-20-17) HMPL Exit
Case No. 2018-00_____

	Annual $EFOR_d$ for Units (September 1 to August 31)								
Unit	9/1/21 to 8/31/22	9/1/22 to 8/31/23	9/1/23 to 8/31/24	9/1/24 to 8/31/25	9/1/25 to 8/31/26	9/1/26 to 8/31/27	9/1/27 to 8/31/28	9/1/28 to 8/31/29	9/1/29 to 8/31/30
Wilson	[redacted]								
Green 1									
Green 2									
HMP&L 1									
HMP&L 2									
Reid CT									
SEPA-BR									
SEPA-HMP&L									

	3 Year $EFOR_d$ for Units (September 1 to August 31)							
	PY 24-25	PY 25-26	PY 26-27	PY 27-28	PY 28-29	PY 29-30	PY 30-31	PY 31-32
Unit	9/1/20 to 8/31/23	9/1/21 to 8/31/24	9/1/22 to 8/31/25	9/1/23 to 8/31/26	9/1/24 to 8/31/27	9/1/25 to 8/31/28	9/1/26 to 8/31/29	9/1/27 to 8/31/30
Wilson	[redacted]							
Green 1								
Green 2								
HMP&L 1								
HMP&L 2								
Reid CT								
SEPA-BR								
SEPA-HMP&L								

Big Rivers Electric Corporation
Capacity Forecast 2018 Budget (10-20-17) HMPL Exit
Case No. 2018-00_____

	Annual GVTC (Generator Verification Test Capacity for Units (November 1 to October 31)								
Unit	**PY 15-16** 11/1/13 to 10/31/14	**PY 16-17** 11/1/14 to 10/31/15	**PY 17-18** 11/1/15 to 10/31/16	**PY 18-19** 11/1/16 to 10/31/17	**PY 19-20** 11/1/17 to 10/31/18	**PY 20-21** 11/1/18 to 10/31/19	**PY 21-22** 11/1/19 to 10/31/20	**PY 22-23** 11/1/20 to 10/31/21	**PY 23-24** 11/1/21 to 10/31/22
Wilson	417	417	417	417	[redacted]				
Green 1	231	231	231	231	[redacted]				
Green 2	223	223	223	223	[redacted]				
HMP&L 1	153	153	153	153	[redacted]				
HMP&L 2	155	159	157	156.7	[redacted]				
Reid CT	56	46	56	50	[redacted]				
SEPA-BR	154	154	154	154	[redacted]				
SEPA-HMP&L	10	10	10	10	[redacted]				

	MISO UCAP								
Unit	**PY 15-16**	**PY 16-17**	**PY 17-18**	**PY 18-19**	**PY 19-20**	**PY 20-21**	**PY 21-22**	**PY 22-23**	**PY 23-24**
Wilson	397.3	399.4	[redacted]						
Green 1	222.4	221.2	[redacted]						
Green 2	219.7	217.9	[redacted]						
HMP&L 1	145.8	145.9	[redacted]						
HMP&L 2	146.3	144.4	[redacted]						
Reid CT	47.9	36.6	[redacted]						
SEPA-BR	154.0	154.0	[redacted]						
SEPA-HMP&L	10.0	10.0	[redacted]						
Total	**1343.4**	**1379.4**	[redacted]						

Big Rivers Electric Corporation
Capacity Forecast 2018 Budget (10-20-17) HMPL Exit
Case No. 2018-00_____

	Annual GVTC (Generator Verification Test Capacity for Units (November 1 to October 31)							
Unit	PY 24-25 11/1/22 to 10/31/23	PY 25-26 11/1/23 to 10/31/24	PY 26-27 11/1/24 to 10/31/25	PY 27-28 11/1/25 to 10/31/26	PY 28-29 11/1/26 to 10/31/27	PY 29-30 11/1/27 to 10/31/28	PY 30-31 11/1/28 to 10/31/29	PY 31-32 11/1/28 to 10/31/30
Wilson	[redacted]							
Green 1								
Green 2								
HMP&L 1								
HMP&L 2								
Reid CT								
SEPA-BR								
SEPA-HMP&L								

	MISO UCAP							
Unit	PY 24-25	PY 25-26	PY 26-27	PY 27-28	PY 28-29	PY 29-30	PY 30-31	PY 31-32
Wilson	[redacted]							
Green 1								
Green 2								
HMP&L 1								
HMP&L 2								
Reid CT								
SEPA-BR								
SEPA-HMP&L								
Total								

Big Rivers Electric Corporation
Capacity Forecast 2018 Budget (10-20-17) HMPL Exit
Case No. 2018-00_____

	Annual $EFOR_d$ for Units (September 1 to August 31)								
Unit	9/1/12 to 8/31/13	9/1/13 to 8/31/14	9/1/14 to 8/31/15	9/1/15 to 8/31/16	9/1/16 to 8/31/17	9/1/17 to 8/31/18	9/1/18 to 8/31/19	9/1/19 to 8/31/20	9/1/20 to 8/31/21
Wilson	5.48%	6.07%	1.46%	4.73%	14.00%	[redacted]	[redacted]	[redacted]	[redacted]
Green 1	2.63%	7.98%	2.58%	6.02%	6.00%	[redacted]	[redacted]	[redacted]	[redacted]
Green 2	1.52%	0.94%	4.77%	1.98%	2.98%	[redacted]	[redacted]	[redacted]	[redacted]
HMP&L 1	6.37%	2.82%	4.62%	13.57%	15.54%	[redacted]	[redacted]	[redacted]	[redacted]
HMP&L 2	6.31%	4.46%	17.55%	33.74%	11.70%	[redacted]	[redacted]	[redacted]	[redacted]
Reid CT	17.56%	13.15%	29.63%	80.68%	19.07%	[redacted]	[redacted]	[redacted]	[redacted]
SEPA-BR					0.00%	[redacted]	[redacted]	[redacted]	[redacted]
SEPA-HMP&L					0.00%	[redacted]	[redacted]	[redacted]	[redacted]

	3 Year $EFOR_d$ for Units (September 1 to August 31)								
	PY 15-16	PY 16-17	PY 17-18	PY 18-19	PY 19-20	PY 20-21	PY 21-22	PY 22-23	PY 23-24
Unit	9/1/11 to 8/31/14	9/1/12 to 8/31/15	9/1/13 to 8/31/16	9/1/14 to 8/31/17	9/1/15 to 8/31/18	9/1/16 to 8/31/19	9/1/17 to 8/31/20	9/1/18 to 8/31/21	9/1/19 to 8/31/22
Wilson	4.73%	4.21%	3.95%	6.73%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Green 1	3.71%	4.24%	5.36%	4.87%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Green 2	1.48%	2.30%	2.45%	3.24%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
HMP&L 1	4.71%	4.63%	6.69%	11.24%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
HMP&L 2	5.60%	9.21%	18.60%	21.00%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Reid CT	14.41%	20.44%	43.46%	43.13%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SEPA-BR	0.00%	0.00%	4.61%	0.00%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SEPA-HMP&L	0.00%	0.00%	4.61%	0.00%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Big Rivers Electric Corporation
Capacity Forecast 2018 Budget (10-20-17) HMPL Exit
Case No. 2018-00_____

	Annual EFOR$_d$ for Units (September 1 to August 31)								
Unit	9/1/21 to 8/31/22	9/1/22 to 8/31/23	9/1/23 to 8/31/24	9/1/24 to 8/31/25	9/1/25 to 8/31/26	9/1/26 to 8/31/27	9/1/27 to 8/31/28	9/1/28 to 8/31/29	9/1/29 to 8/31/30
Wilson	[redacted]								
Green 1									
Green 2									
HMP&L 1									
HMP&L 2									
Reid CT									
SEPA-BR									
SEPA-HMP&L									

	3 Year EFOR$_d$ for Units (September 1 to August 31)							
Unit	PY 24-25	PY 25-26	PY 26-27	PY 27-28	PY 28-29	PY 29-30	PY 30-31	PY 31-32
	9/1/20 to 8/31/23	9/1/21 to 8/31/24	9/1/22 to 8/31/25	9/1/23 to 8/31/26	9/1/24 to 8/31/27	9/1/25 to 8/31/28	9/1/26 to 8/31/29	9/1/27 to 8/31/30
Wilson	[redacted]							
Green 1								
Green 2								
HMP&L 1								
HMP&L 2								
Reid CT								
SEPA-BR								
SEPA-HMP&L								

Sheet Name - Capacity Volume Fcast No HMPL

Big Rivers Electric Corporation
Capacity Forecast 2018 Budget (10-20-17) HMPL Exit
Case No. 2018-00_____

	Annual GVTC (Generator Verification Test Capacity for Units (November 1 to October 31)								
Unit	PY 15-16	PY 16-17	PY 17-18	PY 18-19	PY 19-20	PY 20-21	PY 21-22	PY 22-23	PY 23-24
	11/1/13 to 10/31/14	11/1/14 to 10/31/15	11/1/15 to 10/31/16	11/1/16 to 10/31/17	11/1/17 to 10/31/18	11/1/18 to 10/31/19	11/1/19 to 10/31/20	11/1/20 to 10/31/21	11/1/21 to 10/31/22
Wilson	417	417	417	417	[redacted]				
Green 1	231	231	231	231	[redacted]				
Green 2	223	223	223	223	[redacted]				
HMP&L 1	153	153	153	153	[redacted]				
HMP&L 2	155	159	157	156.7	[redacted]				
Reid CT	56	46	56	50	[redacted]				
SEPA-BR	154	154	154	154	[redacted]				
SEPA-HMP&L	10	10	10	10	[redacted]				

	MISO UCAP								
Unit	PY 15-16	PY 16-17	PY 17-18	PY 18-19	PY 19-20	PY 20-21	PY 21-22	PY 22-23	PY 23-24
Wilson	397.3	399.4	[redacted]						
Green 1	222.4	221.2	[redacted]						
Green 2	219.7	217.9	[redacted]						
HMP&L 1	145.8	145.9	[redacted]						
HMP&L 2	146.3	144.4	[redacted]						
Reid CT	47.9	36.6	[redacted]						
SEPA-BR	154.0	154.0	[redacted]						
SEPA-HMP&L	10.0	10.0	[redacted]						
Total	**1343.4**	**1379.4**	[redacted]						

Big Rivers Electric Corporation
Capacity Forecast 2018 Budget (10-20-17) HMPL Exit
Case No. 2018-00_____

	Annual GVTC (Generator Verification Test Capacity for Units (November 1 to October 31)							
Unit	PY 24-25	PY 25-26	PY 26-27	PY 27-28	PY 28-29	PY 29-30	PY 30-31	PY 31-32
	11/1/22 to 10/31/23	11/1/23 to 10/31/24	11/1/24 to 10/31/25	11/1/25 to 10/31/26	11/1/26 to 10/31/27	11/1/27 to 10/31/28	11/1/28 to 10/31/29	11/1/28 to 10/31/30
Wilson	[redacted]							
Green 1	[redacted]							
Green 2	[redacted]							
HMP&L 1	[redacted]							
HMP&L 2	[redacted]							
Reid CT	[redacted]							
SEPA-BR	[redacted]							
SEPA-HMP&L	[redacted]							

	MISO UCAP							
Unit	PY 24-25	PY 25-26	PY 26-27	PY 27-28	PY 28-29	PY 29-30	PY 30-31	PY 31-32
Wilson	[redacted]							
Green 1	[redacted]							
Green 2	[redacted]							
HMP&L 1	[redacted]							
HMP&L 2	[redacted]							
Reid CT	[redacted]							
SEPA-BR	[redacted]							
SEPA-HMP&L	[redacted]							
Total	[redacted]							

Big Rivers Electric Corporation
Capacity Forecast 2018 Budget (10-20-17) HMPL Exit
Case No. 2018-00_____

EFOR$_d$ for Units (September 1, 2016 to August 31, 2017)					
Unit	**Actual EFOR$_d$ 9/1/16 to 6/1/17**	**Actual EFOR for July**	**Actual EFOR for August**	**Forecasted EFOR$_d$ 9/1/16 to 8/31/17**	**Comments**
Days	**303**	**31**	**31**	**365**	
Wilson	13.39%	16.17%	17.80%	**14.00%**	
Green 1	5.91%	0.00%	12.90%	**6.00%**	
Green 2	1.32%	10.54%	11.60%	**2.98%**	
HMP&L 1	9.68%	16.13%	72.20%	**15.54%**	
HMP&L 2	11.90%	14.24%	7.20%	**11.70%**	
Reid 1					Unit idled
Reid CT	19.07%			**19.07%**	Assumed same actual through 6/1/17

Big Rivers Electric Corporation
Capacity Forecast 2018 Budget (11-7-17) HMPL Exit
Case No. 2018-00______

PRMR (Planning Reserve Margin Requirements)									
						Big Rivers			
PY	Native	New Load	New Load	HMP&L	Domtar	NCP	NCP to CP Factor	CP	Losses, %
13-14								1,583.0	1.3%
14-15								1,084.2	1.3%
15-16	651	0	0	109	0	760	95.13%	723.0	1.5%
16-17	682	9	0	109	50	850	95.76%	814.0	1.6%
17-18	[redacted]								
18-19	[redacted]								
19-20	[redacted]								
20-21	[redacted]								
21-22	[redacted]								
22-23	[redacted]								
23-24	[redacted]								
24-25	[redacted]								
25-26	[redacted]								
26-27	[redacted]								
27-28	[redacted]								
28-29	[redacted]								
29-30	[redacted]								
30-31	[redacted]								
31-32	[redacted]								

Big Rivers Electric Corporation
Capacity Forecast 2018 Budget (11-7-17) HMPL Exit
Case No. 2018-00_____

Year	Total Capacity		Capacity Sold (Hedged)						
			Jan-May			Jun-Dec			
	Jan-May	Jun-Dec	MW	$/MW-day	$	MW	$/MW-day	$	MW
2018	[redacted]								
2019	[redacted]								
2020	[redacted]								
2021	[redacted]								
2022	[redacted]								
2023	[redacted]								
2024	[redacted]								
2025	[redacted]								
2026	[redacted]								
2027	[redacted]								
2028	[redacted]								
2029	[redacted]								
2030	[redacted]								
2031	[redacted]								

Sheet Name - Base Case

Big Rivers Electric Corporation
Capacity Forecast 2018 Budget (11-7-17) HMPL Exit
Case No. 2018-00_____

PY	CP w/Loss	PRM, %	PRMR	HMP&L CP	HMP&L CP with Losses	HMP&L PRMR	Big Rivers UCAP	Nebraska Sale
13-14	1,603.6	6.2%	1,703.0				1,846.5	
14-15	1,098.3	7.3%	1,178.5				1,809.6	
15-16	733.8	7.1%	785.9	103.7	105.2	112.7	1,389.8	
16-17	827.0	7.6%	889.9	104.4	106.1	114.1	1,379.4	
17-18	[redacted]							
18-19	[redacted]							
19-20	[redacted]							
20-21	[redacted]							
21-22	[redacted]							
22-23	[redacted]							
23-24	[redacted]							
24-25	[redacted]							
25-26	[redacted]							
26-27	[redacted]							
27-28	[redacted]							
28-29	[redacted]							
29-30	[redacted]							
30-31	[redacted]							
31-32	[redacted]							

Sheet Name - Base Case

Big Rivers Electric Corporation
Capacity Forecast 2018 Budget (11-7-17) HMPL Exit
Case No. 2018-00_____

Year	Capacity Forecast					Capacity Revenue, $		
	Jan-May		Jun-Dec					
	$/MW-day	$	MW	$/MW-day	$	Hedged	Forecast	Total
2018	[redacted]							
2019	[redacted]							
2020	[redacted]							
2021	[redacted]							
2022	[redacted]							
2023	[redacted]							
2024	[redacted]							
2025	[redacted]							
2026	[redacted]							
2027	[redacted]							
2028	[redacted]							
2029	[redacted]							
2030	[redacted]							
2031	[redacted]							

Sheet Name - Base Case

Big Rivers Electric Corporation
Capacity Forecast 2018 Budget (11-7-17) HMPL Exit
Case No. 2018-00_____

n Member Capacity Transactions				MISO Capacity	Capacity Price Forecast, $/MW-Day			MISO Actual Capacity Prices
PY	Nebraska Purchase @ SPP	Kentucky Municipals	New Sale		2018 Budget	2017 Budget	2016 Budget	
13-14				143.5				
14-15				631.1				
15-16				603.9				$ 3.48
16-17				489.5			$ 49.32	$ 72.00
17-18	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
18-19	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
19-20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
20-21	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
21-22	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
22-23	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
23-24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
24-25	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
25-26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
26-27	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
27-28	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
28-29	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
29-30	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
30-31	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
31-32	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	

Sheet Name - Base Case

Big Rivers Electric Corporation
Capacity Forecast 2018 Budget (11-7-17) HMPL Exit
Case No. 2018-00______

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Sheet Name - Base Case

Big Rivers Electric Corporation
Capacity Forecast 2018 Budget (11-7-17) HMPL Exit
Case No. 2018-00_____

PRMR (Planning Reserve Margin Requirements)									
						Big Rivers			
PY	Native	New Load	New Load	HMP&L	Domtar	NCP	NCP to CP Factor	CP	Losses, %
13-14								1,583.0	1.3%
14-15								1,084.2	1.3%
15-16	651	0	0	109	0	760	95.13%	723.0	1.5%
16-17	682	9	0	109	50	850	95.76%	814.0	1.6%
17-18	[redacted]								
18-19	[redacted]								
19-20	[redacted]								
20-21	[redacted]								
21-22	[redacted]								
22-23	[redacted]								
23-24	[redacted]								
24-25	[redacted]								
25-26	[redacted]								
26-27	[redacted]								
27-28	[redacted]								
28-29	[redacted]								
29-30	[redacted]								
30-31	[redacted]								
31-32	[redacted]								

Sheet Name - Base Case (without HMPL)

Big Rivers Electric Corporation
Capacity Forecast 2018 Budget (11-7-17) HMPL Exit
Case No. 2018-00_____

Year	Total Capacity		Capacity Sold (Hedged)						
			Jan-May			Jun-Dec			
	Jan-May	Jun-Dec	MW	$/MW-day	$	MW	$/MW-day	$	MW
2018	[redacted]								
2019	[redacted]								
2020	[redacted]								
2021	[redacted]								
2022	[redacted]								
2023	[redacted]								
2024	[redacted]								
2025	[redacted]								
2026	[redacted]								
2027	[redacted]								
2028	[redacted]								
2029	[redacted]								
2030	[redacted]								
2031	[redacted]								

Sheet Name - Base Case (without HMPL)

Big Rivers Electric Corporation
Capacity Forecast 2018 Budget (11-7-17) HMPL Exit
Case No. 2018-00_____

								N
PY	CP w/Loss	PRM, %	PRMR	HMP&L CP	HMP&L CP with Losses	HMP&L PRMR	Big Rivers UCAP	Nebraska Sale
13-14	1,603.6	6.2%	1,703.0				1,846.5	
14-15	1,098.3	7.3%	1,178.5				1,809.6	
15-16	733.8	7.1%	785.9	103.7	105.2	112.7	1,389.8	
16-17	827.0	7.6%	889.9	104.4	106.1	114.1	1,379.4	
17-18	[redacted]							
18-19	[redacted]							
19-20	[redacted]							
20-21	[redacted]							
21-22	[redacted]							
22-23	[redacted]							
23-24	[redacted]							
24-25	[redacted]							
25-26	[redacted]							
26-27	[redacted]							
27-28	[redacted]							
28-29	[redacted]							
29-30	[redacted]							
30-31	[redacted]							
31-32	[redacted]							

Sheet Name - Base Case (without HMPL)

Big Rivers Electric Corporation
Capacity Forecast 2018 Budget (11-7-17) HMPL Exit
Case No. 2018-00_____

Year	Capacity Forecast					Capacity Revenue, $		
	Jan-May		Jun-Dec					
	$/MW-day	$	MW	$/MW-day	$	Hedged	Forecast	Total
2018	[redacted]							
2019	[redacted]							
2020	[redacted]							
2021	[redacted]							
2022	[redacted]							
2023	[redacted]							
2024	[redacted]							
2025	[redacted]							
2026	[redacted]							
2027	[redacted]							
2028	[redacted]							
2029	[redacted]							
2030	[redacted]							
2031	[redacted]							

Sheet Name - Base Case (without HMPL)

Big Rivers Electric Corporation
Capacity Forecast 2018 Budget (11-7-17) HMPL Exit
Case No. 2018-00_____

n Member Capacity Transactions				MISO Capacity	Capacity Price Forecast, $/MW-Day			MISO Actual Capacity Prices
PY	Nebraska Purchase @ SPP	Kentucky Municipals	New Sale		2018 Budget	2017 Budget	2016 Budget	
13-14				143.5				
14-15				631.1				
15-16				603.9				$ 3.48
16-17				489.5			$ 49.32	$ 72.00
17-18	[redacted]							
18-19	[redacted]							
19-20	[redacted]							
20-21	[redacted]							
21-22	[redacted]							
22-23	[redacted]							
23-24	[redacted]							
24-25	[redacted]							
25-26	[redacted]							
26-27	[redacted]							
27-28	[redacted]							
28-29	[redacted]							
29-30	[redacted]							
30-31	[redacted]							
31-32	[redacted]							

Sheet Name - Base Case (without HMPL)

Year
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Big Rivers Electric Corporation
Capacity Forecast 2018 Budget (11-7-17) HMPL Exit
Case No. 2018-00_____

	Annual $EFOR_d$ for Units (September 1 to August 31)								
Unit	9/1/12 to 8/31/13	9/1/13 to 8/31/14	9/1/14 to 8/31/15	9/1/15 to 8/31/16	9/1/16 to 8/31/17	9/1/17 to 8/31/18	9/1/18 to 8/31/19	9/1/19 to 8/31/20	9/1/20 to 8/31/21
Wilson	5.48%	6.07%	1.46%	4.73%	14.00%	[redacted]	[redacted]	[redacted]	[redacted]
Green 1	2.63%	7.98%	2.58%	6.02%	6.00%	[redacted]	[redacted]	[redacted]	[redacted]
Green 2	1.52%	0.94%	4.77%	1.98%	2.98%	[redacted]	[redacted]	[redacted]	[redacted]
HMP&L 1	6.37%	2.82%	4.62%	13.57%	15.54%	[redacted]	[redacted]	[redacted]	[redacted]
HMP&L 2	6.31%	4.46%	17.55%	33.74%	11.70%	[redacted]	[redacted]	[redacted]	[redacted]
Reid CT	17.56%	13.15%	29.63%	80.68%	19.07%	[redacted]	[redacted]	[redacted]	[redacted]
SEPA-BR					0.00%	[redacted]	[redacted]	[redacted]	[redacted]
SEPA-HMP&L					0.00%	[redacted]	[redacted]	[redacted]	[redacted]

	3 Year $EFOR_d$ for Units (September 1 to August 31)								
Unit	PY 15-16	PY 16-17	PY 17-18	PY 18-19	PY 19-20	PY 20-21	PY 21-22	PY 22-23	PY 23-24
	9/1/11 to 8/31/14	9/1/12 to 8/31/15	9/1/13 to 8/31/16	9/1/14 to 8/31/17	9/1/15 to 8/31/18	9/1/16 to 8/31/19	9/1/17 to 8/31/20	9/1/18 to 8/31/21	9/1/19 to 8/31/22
Wilson	4.73%	4.21%	3.95%	6.73%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Green 1	3.71%	4.24%	5.36%	4.87%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Green 2	1.48%	2.30%	2.45%	3.24%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
HMP&L 1	4.71%	4.63%	6.69%	11.24%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
HMP&L 2	5.60%	9.21%	18.60%	21.00%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Reid CT	14.41%	20.44%	43.46%	43.13%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SEPA-BR	0.00%	0.00%	4.61%	0.00%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SEPA-HMP&L	0.00%	0.00%	4.61%	0.00%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Sheet Name - Capacity Volume Forecast

Big Rivers Electric Corporation
Capacity Forecast 2018 Budget (11-7-17) HMPL Exit
Case No. 2018-00_____

	Annual $EFOR_d$ for Units (September 1 to August 31)								
Unit	9/1/21 to 8/31/22	9/1/22 to 8/31/23	9/1/23 to 8/31/24	9/1/24 to 8/31/25	9/1/25 to 8/31/26	9/1/26 to 8/31/27	9/1/27 to 8/31/28	9/1/28 to 8/31/29	9/1/29 to 8/31/30
Wilson	[redacted]								
Green 1									
Green 2									
HMP&L 1									
HMP&L 2									
Reid CT									
SEPA-BR									
SEPA-HMP&L									

	3 Year $EFOR_d$ for Units (September 1 to August 31)							
	PY 24-25	PY 25-26	PY 26-27	PY 27-28	PY 28-29	PY 29-30	PY 30-31	PY 31-32
Unit	9/1/20 to 8/31/23	9/1/21 to 8/31/24	9/1/22 to 8/31/25	9/1/23 to 8/31/26	9/1/24 to 8/31/27	9/1/25 to 8/31/28	9/1/26 to 8/31/29	9/1/27 to 8/31/30
Wilson	[redacted]							
Green 1								
Green 2								
HMP&L 1								
HMP&L 2								
Reid CT								
SEPA-BR								
SEPA-HMP&L								

Sheet Name - Capacity Volume Forecast

Big Rivers Electric Corporation
Capacity Forecast 2018 Budget (11-7-17) HMPL Exit
Case No. 2018-00_____

	Annual GVTC (Generator Verification Test Capacity for Units (November 1 to October 31)								
Unit	PY 15-16 11/1/13 to 10/31/14	PY 16-17 11/1/14 to 10/31/15	PY 17-18 11/1/15 to 10/31/16	PY 18-19 11/1/16 to 10/31/17	PY 19-20 11/1/17 to 10/31/18	PY 20-21 11/1/18 to 10/31/19	PY 21-22 11/1/19 to 10/31/20	PY 22-23 11/1/20 to 10/31/21	PY 23-24 11/1/21 to 10/31/22
Wilson	417	417	417	417	[redacted]				
Green 1	231	231	231	231					
Green 2	223	223	223	223					
HMP&L 1	153	153	153	153					
HMP&L 2	155	159	157	156.7					
Reid CT	56	46	56	50					
SEPA-BR	154	154	154	154					
SEPA-HMP&L	10	10	10	10					

	MISO UCAP								
Unit	PY 15-16	PY 16-17	PY 17-18	PY 18-19	PY 19-20	PY 20-21	PY 21-22	PY 22-23	PY 23-24
Wilson	397.3	399.4	[redacted]						
Green 1	222.4	221.2							
Green 2	219.7	217.9							
HMP&L 1	145.8	145.9							
HMP&L 2	146.3	144.4							
Reid CT	47.9	36.6							
SEPA-BR	154.0	154.0							
SEPA-HMP&L	10.0	10.0							
Total	**1343.4**	**1379.4**							

Sheet Name - Capacity Volume Forecast

Big Rivers Electric Corporation
Capacity Forecast 2018 Budget (11-7-17) HMPL Exit
Case No. 2018-00_____

	Annual GVTC (Generator Verification Test Capacity for Units (November 1 to October 31)							
Unit	PY 24-25	PY 25-26	PY 26-27	PY 27-28	PY 28-29	PY 29-30	PY 30-31	PY 31-32
	11/1/22 to 10/31/23	11/1/23 to 10/31/24	11/1/24 to 10/31/25	11/1/25 to 10/31/26	11/1/26 to 10/31/27	11/1/27 to 10/31/28	11/1/28 to 10/31/29	11/1/28 to 10/31/30
Wilson	[redacted]							
Green 1								
Green 2								
HMP&L 1								
HMP&L 2								
Reid CT								
SEPA-BR								
SEPA-HMP&L								

	MISO UCAP							
Unit	PY 24-25	PY 25-26	PY 26-27	PY 27-28	PY 28-29	PY 29-30	PY 30-31	PY 31-32
Wilson	[redacted]							
Green 1								
Green 2								
HMP&L 1								
HMP&L 2								
Reid CT								
SEPA-BR								
SEPA-HMP&L								
Total								

Big Rivers Electric Corporation
Capacity Forecast 2018 Budget (11-7-17) HMP Exit
Case No. 2018-00_____

	Annual EFOR$_d$ for Units (September 1 to August 31)								
Unit	9/1/12 to 8/31/13	9/1/13 to 8/31/14	9/1/14 to 8/31/15	9/1/15 to 8/31/16	9/1/16 to 8/31/17	9/1/17 to 8/31/18	9/1/18 to 8/31/19	9/1/19 to 8/31/20	9/1/20 to 8/31/21
Wilson	5.48%	6.07%	1.46%	4.73%	14.00%	[redacted]			
Green 1	2.63%	7.98%	2.58%	6.02%	6.00%	[redacted]			
Green 2	1.52%	0.94%	4.77%	1.98%	2.98%	[redacted]			
HMP&L 1	6.37%	2.82%	4.62%	13.57%	15.54%	[redacted]			
HMP&L 2	6.31%	4.46%	17.55%	33.74%	11.70%	[redacted]			
Reid CT	17.56%	13.15%	29.63%	80.68%	19.07%	[redacted]			
SEPA-BR					0.00%	[redacted]			
SEPA-HMP&L					0.00%	[redacted]			

	3 Year EFOR$_d$ for Units (September 1 to August 31)								
Unit	PY 15-16	PY 16-17	PY 17-18	PY 18-19	PY 19-20	PY 20-21	PY 21-22	PY 22-23	PY 23-24
	9/1/11 to 8/31/14	9/1/12 to 8/31/15	9/1/13 to 8/31/16	9/1/14 to 8/31/17	9/1/15 to 8/31/18	9/1/16 to 8/31/19	9/1/17 to 8/31/20	9/1/18 to 8/31/21	9/1/19 to 8/31/22
Wilson	4.73%	4.21%	3.95%	6.73%	[redacted]				
Green 1	3.71%	4.24%	5.36%	4.87%	[redacted]				
Green 2	1.48%	2.30%	2.45%	3.24%	[redacted]				
HMP&L 1	4.71%	4.63%	6.69%	11.24%	[redacted]				
HMP&L 2	5.60%	9.21%	18.60%	21.00%	[redacted]				
Reid CT	14.41%	20.44%	43.46%	43.13%	[redacted]				
SEPA-BR	0.00%	0.00%	4.61%	0.00%	[redacted]				
SEPA-HMP&L	0.00%	0.00%	4.61%	0.00%	[redacted]				

Sheet Name - Capacity Volume Fcast No HMPL

Big Rivers Electric Corporation
Capacity Forecast 2018 Budget (11-7-17) HMP Exit
Case No. 2018-00_____

	Annual $EFOR_d$ for Units (September 1 to August 31)								
Unit	9/1/21 to 8/31/22	9/1/22 to 8/31/23	9/1/23 to 8/31/24	9/1/24 to 8/31/25	9/1/25 to 8/31/26	9/1/26 to 8/31/27	9/1/27 to 8/31/28	9/1/28 to 8/31/29	9/1/29 to 8/31/30
Wilson	[redacted]								
Green 1									
Green 2									
HMP&L 1									
HMP&L 2									
Reid CT									
SEPA-BR									
SEPA-HMP&L									

	3 Year $EFOR_d$ for Units (September 1 to August 31)							
Unit	**PY 24-25**	**PY 25-26**	**PY 26-27**	**PY 27-28**	**PY 28-29**	**PY 29-30**	**PY 30-31**	**PY 31-32**
	9/1/20 to 8/31/23	9/1/21 to 8/31/24	9/1/22 to 8/31/25	9/1/23 to 8/31/26	9/1/24 to 8/31/27	9/1/25 to 8/31/28	9/1/26 to 8/31/29	9/1/27 to 8/31/30
Wilson	[redacted]							
Green 1								
Green 2								
HMP&L 1								
HMP&L 2								
Reid CT								
SEPA-BR								
SEPA-HMP&L								

Sheet Name - Capacity Volume Fcast No HMPL

Big Rivers Electric Corporation
Capacity Forecast 2018 Budget (11-7-17) HMP Exit
Case No. 2018-00_____

	Annual GVTC (Generator Verification Test Capacity for Units (November 1 to October 31)								
Unit	PY 15-16	PY 16-17	PY 17-18	PY 18-19	PY 19-20	PY 20-21	PY 21-22	PY 22-23	PY 23-24
	11/1/13 to 10/31/14	11/1/14 to 10/31/15	11/1/15 to 10/31/16	11/1/16 to 10/31/17	11/1/17 to 10/31/18	11/1/18 to 10/31/19	11/1/19 to 10/31/20	11/1/20 to 10/31/21	11/1/21 to 10/31/22
Wilson	417	417	417	417	[redacted]				
Green 1	231	231	231	231	[redacted]				
Green 2	223	223	223	223	[redacted]				
HMP&L 1	153	153	153		[redacted]				
HMP&L 2	155	159	157		[redacted]				
Reid CT	56	46	56	50	[redacted]				
SEPA-BR	154	154	154	154	[redacted]				
SEPA-HMP&L	10	10	10	10	[redacted]				

	MISO UCAP								
Unit	PY 15-16	PY 16-17	PY 17-18	PY 18-19	PY 19-20	PY 20-21	PY 21-22	PY 22-23	PY 23-24
Wilson	397.3	399.4	[redacted]						
Green 1	222.4	221.2	[redacted]						
Green 2	219.7	217.9	[redacted]						
HMP&L 1	145.8	145.9	[redacted]						
HMP&L 2	146.3	144.4	[redacted]						
Reid CT	47.9	36.6	[redacted]						
SEPA-BR	154.0	154.0	[redacted]						
SEPA-HMP&L	10.0	10.0	[redacted]						
Total	**1343.4**	**1379.4**	[redacted]						

Big Rivers Electric Corporation
Capacity Forecast 2018 Budget (11-7-17) HMP Exit
Case No. 2018-00_____

	Annual GVTC (Generator Verification Test Capacity for Units (November 1 to October 31)							
Unit	PY 24-25	PY 25-26	PY 26-27	PY 27-28	PY 28-29	PY 29-30	PY 30-31	PY 31-32
	11/1/22 to 10/31/23	11/1/23 to 10/31/24	11/1/24 to 10/31/25	11/1/25 to 10/31/26	11/1/26 to 10/31/27	11/1/27 to 10/31/28	11/1/28 to 10/31/29	11/1/28 to 10/31/30
Wilson	[redacted]							
Green 1	[redacted]							
Green 2	[redacted]							
HMP&L 1	[redacted]							
HMP&L 2	[redacted]							
Reid CT	[redacted]							
SEPA-BR	[redacted]							
SEPA-HMP&L	[redacted]							

	MISO UCAP							
Unit	PY 24-25	PY 25-26	PY 26-27	PY 27-28	PY 28-29	PY 29-30	PY 30-31	PY 31-32
Wilson	[redacted]							
Green 1	[redacted]							
Green 2	[redacted]							
HMP&L 1	[redacted]							
HMP&L 2	[redacted]							
Reid CT	[redacted]							
SEPA-BR	[redacted]							
SEPA-HMP&L	[redacted]							
Total	[redacted]							

Sheet Name - Capacity Volume Fcast No HMPL

EFOR$_d$ for Units (September 1, 2016 to August 31, 2017)					
Unit	**Actual EFOR$_d$ 9/1/16 to 6/1/17**	**Actual EFOR for July**	**Actual EFOR for August**	**Forecasted EFOR$_d$ 9/1/16 to 8/31/17**	**Comments**
Days	**303**	**31**	**31**	**365**	
Wilson	13.39%	16.17%	17.80%	**14.00%**	
Green 1	5.91%	0.00%	12.90%	**6.00%**	
Green 2	1.32%	10.54%	11.60%	**2.98%**	
HMP&L 1	9.68%	16.13%	72.20%	**15.54%**	
HMP&L 2	11.90%	14.24%	7.20%	**11.70%**	
Reid 1					Unit idled
Reid CT	19.07%			**19.07%**	Assumed same actual through 6/1/17

Sheet Name - EFOR Forecast 16-17

Big Rivers Electric Corporation
Production Fixed Costs (2017-2031 Long-Term Forecast - 11-12-2017)
Case No. 2018-00_____

Date: 10/11/2017

Annual Inflation Rate	[redacted]

	Big Rivers Production (Net)(without Coleman) Fixed O&M Costs (2017-2031 Long-Term Forecast)						
	2018	2019	2020	2021	2022	2023	2024
Non-Labor Routine	[redacted]						
Non-Labor Outage							
Labor Plant Staff							
Labor Support Staff							
Total Fixed Cost							
Total Capital Costs							
Plant Capital Costs							
ECP Capital Costs							

	Big Rivers Production (Net)(includes Coleman) Fixed O&M Costs (2017-2031 Long-Term Forecast)						
	2018	2019	2020	2021	2022	2023	2024
Non-Labor Routine	[redacted]						
Non-Labor Outage							
Labor Plant Staff							
Labor Support Staff							
Total Fixed Cost							
Total Capital Costs							
Plant Capital Costs							
ECP Capital Costs							

Sheet Name - Station II Exit

Big Rivers Electric Corporation
Production Fixed Costs (2017-2031 Long-Term Forecast - 11-12-2017)
Case No. 2018-00_____

Date: 10/11/2017

Annual Inflation Rate	[redacted]

	Big Rivers Production (Net)(without Coleman) Fixed O&M Costs (2017-2031 Long-Term Forecast)						
	2025	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Non-Labor Routine	[redacted]						
Non-Labor Outage	[redacted]						
Labor Plant Staff	[redacted]						
Labor Support Staff	[redacted]						
Total Fixed Cost	[redacted]						
Total Capital Costs	[redacted]						
Plant Capital Costs	[redacted]						
ECP Capital Costs	[redacted]						

	Big Rivers Production (Net)(includes Coleman) Fixed O&M Costs (2017-2031 Long-Term Forecast)						
	2025	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Non-Labor Routine	[redacted]						
Non-Labor Outage	[redacted]						
Labor Plant Staff	[redacted]						
Labor Support Staff	[redacted]						
Total Fixed Cost	[redacted]						
Total Capital Costs	[redacted]						
Plant Capital Costs	[redacted]						
ECP Capital Costs	[redacted]						

Sheet Name - Station II Exit

Big Rivers Electric Corporation
Production Fixed Costs (2017-2031 Long-Term Forecast - 11-12-2017)
Case No. 2018-00_____

Date: 10/11/2017

Annual Inflation Rate	[redacted]

	Wilson Fixed O&M Costs (2017-2031 Long-Term Forecast)						
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Non-Labor Routine	[redacted]						
Non-Labor Outage	[redacted]						
Labor Plant Staff	[redacted]						
Labor Support Staff	[redacted]						
Total Fixed Cost	[redacted]						
Total Capital Costs	[redacted]						
Plant Capital Costs	[redacted]						
ECP Capital Costs	[redacted]						

	Green (Net) Fixed O&M Costs (2017-2031 Long-Term Forecast)						
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Non-Labor Routine	[redacted]						
Non-Labor Outage	[redacted]						
Labor Plant Staff	[redacted]						
Labor Support Staff	[redacted]						
Total Fixed Cost	[redacted]						
Total Capital Costs	[redacted]						
Plant Capital Costs	[redacted]						
ECP Capital Costs	[redacted]						

Sheet Name - Station II Exit

Big Rivers Electric Corporation
Production Fixed Costs (2017-2031 Long-Term Forecast - 11-12-2017)
Case No. 2018-00_____

Date: 10/11/2017

Annual Inflation Rate	[redacted]

	Wilson Fixed O&M Costs (2017-2031 Long-Term Forecast)						
	2025	2026	2027	2028	2029	2030	2031
Non-Labor Routine	[redacted]						
Non-Labor Outage							
Labor Plant Staff							
Labor Support Staff							
Total Fixed Cost							
Total Capital Costs							
Plant Capital Costs							
ECP Capital Costs							
	Green (Net) Fixed O&M Costs (2017-2031 Long-Term Forecast)						
	2025	2026	2027	2028	2029	2030	2031
Non-Labor Routine	[redacted]						
Non-Labor Outage							
Labor Plant Staff							
Labor Support Staff							
Total Fixed Cost							
Total Capital Costs							
Plant Capital Costs							
ECP Capital Costs							

Sheet Name - Station II Exit

Big Rivers Electric Corporation
Production Fixed Costs (2017-2031 Long-Term Forecast - 11-12-2017)
Case No. 2018-00_____

Date: 10/11/2017

Annual Inflation Rate	[redacted]

	Station II (Net)(without Reid) Fixed O&M Costs (2017-2031 Long-Term Forecast)						
	2018	2019	2020	2021	2022	2023	2024
Non-Labor Routine	[redacted]						
Non-Labor Outage							
Labor Plant Staff							
Labor Support Staff							
Total Fixed Cost							
Total Capital Costs							
Plant Capital Costs							
ECP Capital Costs							
	Reid 1 & Reid CT (Net) Fixed O&M Costs (2017-2031 Long-Term Forecast)						
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Non-Labor Routine	[redacted]						
Non-Labor Outage							
Labor Plant Staff							
Labor Support Staff							
Total Fixed Cost							
Total Capital Costs							
Plant Capital Costs							
ECP Capital Costs							

Sheet Name - Station II Exit

Big Rivers Electric Corporation
Production Fixed Costs (2017-2031 Long-Term Forecast - 11-12-2017)
Case No. 2018-00_____

Date: 10/11/2017

Annual Inflation Rate	[redacted]

	Station II (Net)(without Reid) Fixed O&M Costs (2017-2031 Long-Term Forecast)						
	2025	2026	2027	2028	2029	2030	2031
Non-Labor Routine	[redacted]						
Non-Labor Outage							
Labor Plant Staff							
Labor Support Staff							
Total Fixed Cost							
Total Capital Costs							
Plant Capital Costs							
ECP Capital Costs							
	Reid 1 & Reid CT (Net) Fixed O&M Costs (2017-2031 Long-Term Forecast)						
	2025	2026	2027	2028	2029	2030	2031
Non-Labor Routine	[redacted]						
Non-Labor Outage							
Labor Plant Staff							
Labor Support Staff							
Total Fixed Cost							
Total Capital Costs							
Plant Capital Costs							
ECP Capital Costs							

Sheet Name - Station II Exit

Big Rivers Electric Corporation
Production Fixed Costs (2017-2031 Long-Term Forecast - 11-12-2017)
Case No. 2018-00_____

Date: 10/11/2017

Annual Inflation Rate	[redacted]

	Coleman Fixed O&M Costs (2017-2031 Long-Term Forecast)						
	2018	2019	2020	2021	2022	2023	2024
Non-Labor Routine	[redacted]						
Non-Labor Outage							
Labor Plant Staff							
Labor Support Staff							
Total Fixed Cost							
Total Capital Costs							
Plant Capital Costs							
ECP Capital Costs							

	Reid/Station II (Net) Fixed O&M Costs (2016-2030 Long-Term Forecast)						
	2018	2019	2020	2021	2022	2023	2024
Non-Labor Routine	[redacted]						
Non-Labor Outage							
Labor Plant Staff							
Labor Support Staff							
Total Fixed Cost							
Total Capital Costs							
Plant Capital Costs							
ECP Capital Costs							

Sheet Name - Station II Exit

Big Rivers Electric Corporation
Production Fixed Costs (2017-2031 Long-Term Forecast - 11-12-2017)
Case No. 2018-00_____

Date: 10/11/2017

Annual Inflation Rate	[redacted]

	Coleman Fixed O&M Costs (2017-2031 Long-Term Forecast)						
	2025	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Non-Labor Routine	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non-Labor Outage	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Plant Staff	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Support Staff	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Fixed Cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Capital Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Plant Capital Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ECP Capital Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

	Reid/Station II (Net) Fixed O&M Costs (2016-2030 Long-Term Forecast)						
	2025	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Non-Labor Routine	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non-Labor Outage	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Plant Staff	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Support Staff	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Fixed Cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Capital Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Plant Capital Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ECP Capital Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Sheet Name - Station II Exit

Big Rivers Electric Corporation
Production Fixed Costs (2017-2031 Long-Term Forecast - 11-12-2017)
Case No. 2018-00_____

Date: 10/11/2017

Annual Inflation Rate	[redacted]

	Big Rivers (Net)(w/o Coleman Station) Other Fixed Costs (2017-2031 Long-Term Forecast)						
Year	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Property Tax (estimated)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Property Insurance (estimated)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Depreciation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Interest Expense	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Other Fixed Costs, $	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capacity, MW	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Other Fixed Costs, $/MW-Day	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Other Fixed Costs, $/kW-mo	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

	Big Rivers (Net)(Includes Coleman Station) Other Fixed Costs (2017-2031 Long-Term Forecast)						
Year	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Property Tax (estimated)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Property Insurance (estimated)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Depreciation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Interest Expense	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Other Fixed Costs, $	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capacity, MW	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Other Fixed Costs, $/MW-Day	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Other Fixed Costs, $/kW-mo	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Sheet Name - Other Fixed Cost

Big Rivers Electric Corporation
Production Fixed Costs (2017-2031 Long-Term Forecast - 11-12-2017)
Case No. 2018-00_____

Date: 10/11/2017

Annual Inflation Rate	[redacted]

	Big Rivers (Net)(w/o Coleman Station) Other Fixed Costs (2017-2031 Long-Term Forecast)						
Year	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Property Tax (estimated)	[redacted]						
Property Insurance (estimated)							
Depreciation							
Interest Expense							
Total Other Fixed Costs, $							
Capacity, MW							
Total Other Fixed Costs, $/MW-Day							
Total Other Fixed Costs, $/kW-mo							

	Big Rivers (Net)(Includes Coleman Station) Other Fixed Costs (2017-2031 Long-Term Forecast)						
Year	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Property Tax (estimated)	[redacted]						
Property Insurance (estimated)							
Depreciation							
Interest Expense							
Total Other Fixed Costs, $							
Capacity, MW							
Total Other Fixed Costs, $/MW-Day							
Total Other Fixed Costs, $/kW-mo							

Sheet Name - Other Fixed Cost

Big Rivers Electric Corporation
Production Fixed Costs (2017-2031 Long-Term Forecast - 11-12-2017)
Case No. 2018-00_____

Date: 10/11/2017

Annual Inflation Rate	[redacted]

	Wilson Station Other Fixed Costs (2017-2031 Long-Term Forecast)						
Year	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Property Tax (estimated)	[redacted]						
Property Insurance (estimated)							
Depreciation							
Interest Expense							
Total Other Fixed Costs, $							
Capacity, MW							
Total Other Fixed Costs, $/MW-Day							
Total Other Fixed Costs, $/kW-mo							

	Green Station (Net) Other Fixed Costs (2017-2031 Long-Term Forecast)						
Year	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Property Tax (estimated)	[redacted]						
Property Insurance (estimated)							
Depreciation							
Interest Expense							
Total Other Fixed Costs, $							
Capacity, MW							
Total Other Fixed Costs, $/MW-Day							
Total Other Fixed Costs, $/kW-mo							

Big Rivers Electric Corporation
Production Fixed Costs (2017-2031 Long-Term Forecast - 11-12-2017)
Case No. 2018-00_____

Date: 10/11/2017

Annual Inflation Rate	[redacted]

	Wilson Station Other Fixed Costs (2017-2031 Long-Term Forecast)						
Year	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Property Tax (estimated)	[redacted]						
Property Insurance (estimated)							
Depreciation							
Interest Expense							
Total Other Fixed Costs, $							
Capacity, MW							
Total Other Fixed Costs, $/MW-Day							
Total Other Fixed Costs, $/kW-mo							

	Green Station (Net) Other Fixed Costs (2017-2031 Long-Term Forecast)						
Year	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Property Tax (estimated)	[redacted]						
Property Insurance (estimated)							
Depreciation							
Interest Expense							
Total Other Fixed Costs, $							
Capacity, MW							
Total Other Fixed Costs, $/MW-Day							
Total Other Fixed Costs, $/kW-mo							

Big Rivers Electric Corporation
Production Fixed Costs (2017-2031 Long-Term Forecast - 11-12-2017)
Case No. 2018-00_____

Date: 10/11/2017

Annual Inflation Rate	[redacted]

	Station II (Net) Other Fixed Costs (2017-2031 Long-Term Forecast)						
Year	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Property Tax (estimated)	[redacted]						
Property Insurance (estimated)							
Depreciation							
Interest Expense							
Total Other Fixed Costs, $							
Capacity, MW							
Total Other Fixed Costs, $/MW-Day							
Total Other Fixed Costs, $/kW-mo							

	Reid Station (Net) Other Fixed Costs (2017-2031 Long-Term Forecast)						
Year	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Property Tax (estimated)	[redacted]						
Property Insurance (estimated)							
Depreciation							
Interest Expense							
Total Other Fixed Costs, $							
Capacity, MW							
Total Other Fixed Costs, $/MW-Day							
Total Other Fixed Costs, $/kW-mo							

Big Rivers Electric Corporation
Production Fixed Costs (2017-2031 Long-Term Forecast - 11-12-2017)
Case No. 2018-00_____

Date: 10/11/2017

Annual Inflation Rate	[redacted]

	Station II (Net) Other Fixed Costs (2017-2031 Long-Term Forecast)						
Year	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Property Tax (estimated)	[redacted]						
Property Insurance (estimated)							
Depreciation							
Interest Expense							
Total Other Fixed Costs, $							
Capacity, MW							
Total Other Fixed Costs, $/MW-Day							
Total Other Fixed Costs, $/kW-mo							

	Reid Station (Net) Other Fixed Costs (2017-2031 Long-Term Forecast)						
Year	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Property Tax (estimated)	[redacted]						
Property Insurance (estimated)							
Depreciation							
Interest Expense							
Total Other Fixed Costs, $							
Capacity, MW							
Total Other Fixed Costs, $/MW-Day							
Total Other Fixed Costs, $/kW-mo							

Big Rivers Electric Corporation
Production Fixed Costs (2017-2031 Long-Term Forecast - 11-12-2017)
Case No. 2018-00_____

Date: 10/11/2017

Annual Inflation Rate	
	[redacted]

	Coleman Station Other Fixed Costs (2017-2031 Long-Term Forecast)						
Year	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Property Tax (estimated)	[redacted]						
Property Insurance (estimated)							
Depreciation							
Interest Expense							
Total Other Fixed Costs, $							
Capacity, MW							
Total Other Fixed Costs, $/MW-Day							
Total Other Fixed Costs, $/kW-mo							

Sheet Name - Other Fixed Cost

Big Rivers Electric Corporation
Production Fixed Costs (2017-2031 Long-Term Forecast - 11-12-2017)
Case No. 2018-00______

Date: 10/11/2017

Annual Inflation Rate	[redacted]

	Coleman Station Other Fixed Costs (2017-2031 Long-Term Forecast)						
Year	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Property Tax (estimated)	[redacted]						
Property Insurance (estimated)							
Depreciation							
Interest Expense							
Total Other Fixed Costs, $							
Capacity, MW							
Total Other Fixed Costs, $/MW-Day							
Total Other Fixed Costs, $/kW-mo							

Sheet Name - Other Fixed Cost

2018 - 2031 Planned Outage Schedule (2017-2031 Long-Term Forecast)								
Year	Green Unit 1	Green Unit 2	HMP&L (Station Two) Unit 1	HMP&L (Station Two) Unit 2	Wilson Unit 1	Reid Unit 1	Reid Combustion Turbine	System Total
2018	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			[redacted]
2019	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			[redacted]
2020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			[redacted]
2021	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			[redacted]
2029	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			[redacted]
2030	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			[redacted]
2031	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			[redacted]

Note(s) - 1.- Outages due to Turbine Overhauls are as follows:

[redacted]

2.- Outages due to Environmental Compliance Plan are as follows:

[redacted]

Big Rivers Electric Corporation
Production (FDE) Costs (7-14-16)
Case No. 2018-00_____

	Big Rivers (Net) Production FDE Cost						
Scenario	2018	2019	2020	2021	2022	2023	2024
Base	[redacted]						
Green Gas	[redacted]						
HMP&L Station 2 Gas	[redacted]						
Sebree Gas	[redacted]						
Green Co-Firing	[redacted]						
Sta II Exit	[redacted]						

	Big Rivers (Net) Production Capital Cost (Includes ECP)						
Scenario	2018	2019	2020	2021	2022	2023	2024
Base	[redacted]						
Green Gas	[redacted]						
HMP&L Station 2 Gas	[redacted]						
Sebree Gas	[redacted]						
Green Co-Firing	[redacted]						
Sta II Exit	[redacted]						

	Big Rivers (Net) Production ECP Capital Cost						
Scenario	2018	2019	2020	2021	2022	2023	2024
Base	[redacted]						
Green Gas	[redacted]						
HMP&L Station 2 Gas	[redacted]						
Sebree Gas	[redacted]						
Green Co-Firing	[redacted]						
Sta II Exit	[redacted]						

Sheet Name - Summary

Big Rivers Electric Corporation
Production (FDE) Costs (7-14-16)
Case No. 2018-00_____

	Big Rivers (Net) Production FDE Cost						
Scenario	2025	2026	2027	2028	2029	2030	Total
Base	[redacted]						
Green Gas							
HMP&L Station 2 Gas							
Sebree Gas							
Green Co-Firing							
Sta II Exit							

	Big Rivers (Net) Production Capital Cost (Includes ECP)						
Scenario	2025	2026	2027	2028	2029	2030	Total
Base	[redacted]						
Green Gas							
HMP&L Station 2 Gas							
Sebree Gas							
Green Co-Firing							
Sta II Exit							

	Big Rivers (Net) Production ECP Capital Cost						
Scenario	2025	2026	2027	2028	2029	2030	Total
Base	[redacted]						
Green Gas							
HMP&L Station 2 Gas							
Sebree Gas							
Green Co-Firing							
Sta II Exit							

Sheet Name - Summary

Big Rivers Electric Corporation
Production (FDE) Costs (7-14-16)
Case No. 2018-00______

Date: **7/12/2016**

Annual Inflation Rate [redacted]

BASE CASE

	Big Rivers Production (Net) Fixed O&M Costs (2015-2029 Long-Term Forecast)							
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Non-Labor Routine	$ 26,910,031	$ 27,614,737	[redacted]					
Non-Labor Outage	$ -	$ 5,808,463						
Labor Plant Staff	$ 37,681,664	$ 38,628,506						
Labor Support Staff	$ 2,216,043	$ 2,274,379						
Total Fixed Cost	**$ 66,807,737**	**$ 74,326,085**						
Total Capital Costs	**$ 9,113,508**	**$ 12,830,778**						
Plant Capital Costs	$ 9,113,508	$ 12,830,778						
ECP Capital Costs - Coal	$ -	$ -						
ECP Capital Costs - Gas	$ -	$ -						
	Wilson Fixed O&M Costs (2015-2029 Long-Term Forecast)							
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Non-Labor Routine	$ 10,119,856	$ 10,868,088	[redacted]					
Non-Labor Outage	$ -	$ -						
Labor Plant Staff	$ 12,080,358	$ 12,364,062						
Labor Support Staff	$ 699,657	$ 715,856						
Total Fixed Cost	**$ 22,899,871**	**$ 23,948,006**						
Total Capital Costs	**$ 2,820,140**	**$ 4,237,280**						
Plant Capital Costs	$ 2,820,140	$ 4,237,280						
ECP Capital Costs - Coal	$ -	$ -						
ECP Capital Costs - Gas	$ -	$ -						

Sheet Name - Base

Big Rivers Electric Corporation
Production (FDE) Costs (7-14-16)
Case No. 2018-00______

Date: 7/12/2016

BASE CASE

Annual Inflation Rate [redacted]

	Big Rivers Production (Net) Fixed O&M Costs (2015-2029 Long-Term Forecast)						
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Non-Labor Routine	[redacted]						
Non-Labor Outage	[redacted]						
Labor Plant Staff	[redacted]						
Labor Support Staff	[redacted]						
Total Fixed Cost	[redacted]						
Total Capital Costs	[redacted]						
Plant Capital Costs	[redacted]						
ECP Capital Costs - Coal	[redacted]						
ECP Capital Costs - Gas	[redacted]						

	Wilson Fixed O&M Costs (2015-2029 Long-Term Forecast)						
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Non-Labor Routine	[redacted]						
Non-Labor Outage	[redacted]						
Labor Plant Staff	[redacted]						
Labor Support Staff	[redacted]						
Total Fixed Cost	[redacted]						
Total Capital Costs	[redacted]						
Plant Capital Costs	[redacted]						
ECP Capital Costs - Coal	[redacted]						
ECP Capital Costs - Gas	[redacted]						

Sheet Name - Base

Big Rivers Electric Corporation
Production (FDE) Costs (7-14-16)
Case No. 2018-00_____

Date: **7/12/2016**

Annual Inflation Rate [redacted]

BASE CASE

	Green (Net) Fixed O&M Costs (2015-2029 Long-Term Forecast)							
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Non-Labor Routine	$ 10,232,114	$ 10,386,160	[redacted]					
Non-Labor Outage	$ -	$ 3,328,600						
Labor Plant Staff	$ 14,255,837	$ 14,866,003						
Labor Support Staff	$ 741,563	$ 762,170						
Total Fixed Cost	**$ 25,229,514**	**$ 29,342,933**						
Total Capital Costs	**$ 2,205,000**	**$ 5,553,000**						
Plant Capital Costs	$ 2,205,000	$ 5,553,000						
ECP Capital Costs - Coal	$ -	$ -						
ECP Capital Costs - Gas	$ -	$ -						

	Station II (Net)(without Reid) Fixed O&M Costs (2015-2029 Long-Term Forecast)							
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Non-Labor Routine	$ 5,355,616	$ 5,128,524	[redacted]					
Non-Labor Outage	$ -	$ 2,479,863						
Labor Plant Staff	$ 9,303,035	$ 9,308,084						
Labor Support Staff	$ 774,822	$ 796,353						
Total Fixed Cost	**$ 15,433,473**	**$ 17,712,824**						
Total Capital Costs	**$ 4,088,368**	**$ 3,023,498**						
Plant Capital Costs	$ 4,088,368	$ 3,023,498						
ECP Capital Costs - Coal	$ -	$ -						
ECP Capital Costs - Gas	$ -	$ -						

Sheet Name - Base

Big Rivers Electric Corporation
Production (FDE) Costs (7-14-16)
Case No. 2018-00_____

Date: 7/12/2016

Annual Inflation Rate	[redacted]

BASE CASE

	Green (Net) Fixed O&M Costs (2015-2029 Long-Term Forecast)						
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Non-Labor Routine	[redacted]						
Non-Labor Outage							
Labor Plant Staff							
Labor Support Staff							
Total Fixed Cost							
Total Capital Costs							
Plant Capital Costs							
ECP Capital Costs - Coal							
ECP Capital Costs - Gas							
	Station II (Net)(without Reid) Fixed O&M Costs (2015-2029 Long-Term Forecast)						
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Non-Labor Routine	[redacted]						
Non-Labor Outage							
Labor Plant Staff							
Labor Support Staff							
Total Fixed Cost							
Total Capital Costs							
Plant Capital Costs							
ECP Capital Costs - Coal							
ECP Capital Costs - Gas							

Sheet Name - Base

Big Rivers Electric Corporation
Production (FDE) Costs (7-14-16)
Case No. 2018-00_____

Date: 7/12/2016

BASE CASE

Annual Inflation Rate	[redacted]

	Reid (Net) Fixed O&M Costs (2015-2029 Long-Term Forecast)							
	2016	2017	2018	2019	2020	2021	2022	2023
Non-Labor Routine	$ 235,500	$ 236,000	[redacted]					
Non-Labor Outage	$ -	$ -	[redacted]					
Labor Plant Staff	$ -	$ -	[redacted]					
Labor Support Staff	$ -	$ -	[redacted]					
Total Fixed Cost	**$ 235,500**	**$ 236,000**	[redacted]					
Total Capital Costs	**$ -**	**$ 17,000**	[redacted]					
Plant Capital Costs	$ -	$ 17,000	[redacted]					
ECP Capital Costs - Coal	$ -	$ -	[redacted]					
ECP Capital Costs - Gas	$ -	$ -	[redacted]					

	Coleman Fixed O&M Costs (2015-2029 Long-Term Forecast)							
	2016	2017	2018	2019	2020	2021	2022	2023
Non-Labor Routine	$ 966,945	$ 995,965	[redacted]					
Non-Labor Outage	$ -	$ -	[redacted]					
Labor Plant Staff	$ 2,042,434	$ 2,090,358	[redacted]					
Labor Support Staff	$ -	$ -	[redacted]					
Total Fixed Cost	**$ 3,009,379**	**$ 3,086,323**	[redacted]					
Total Capital Costs	**$ -**	**$ -**	[redacted]					
Plant Capital Costs	$ -	$ -	[redacted]					
ECP Capital Costs - Coal	$ -	$ -	[redacted]					
ECP Capital Costs - Gas	$ -	$ -	[redacted]					

Sheet Name - Base

Big Rivers Electric Corporation
Production (FDE) Costs (7-14-16)
Case No. 2018-00_____

Date: 7/12/2016

Annual Inflation Rate [redacted]

BASE CASE

	Reid (Net) Fixed O&M Costs (2015-2029 Long-Term Forecast)						
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Non-Labor Routine	[redacted]						
Non-Labor Outage							
Labor Plant Staff							
Labor Support Staff							
Total Fixed Cost							
Total Capital Costs							
Plant Capital Costs							
ECP Capital Costs - Coal							
ECP Capital Costs - Gas							

	Coleman Fixed O&M Costs (2015-2029 Long-Term Forecast)						
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Non-Labor Routine	[redacted]						
Non-Labor Outage							
Labor Plant Staff							
Labor Support Staff							
Total Fixed Cost							
Total Capital Costs							
Plant Capital Costs							
ECP Capital Costs - Coal							
ECP Capital Costs - Gas							

Sheet Name - Base

Big Rivers Electric Corporation
Production (FDE) Costs (7-14-16)
Case No. 2018-00_____

Date: 7/12/2016

Annual Inflation Rate [redacted]

GREEN GAS

	Big Rivers Production (Net) Fixed O&M Costs (2015-2029 Long-Term Forecast)							
	2016	2017	2018	2019	2020	2021	2022	2023
Non-Labor Routine	$ 26,910,031	$ 27,614,737	[redacted]					
Non-Labor Outage	$ -	$ 5,808,463						
Labor Plant Staff	$ 37,681,664	$ 38,628,506						
Labor Support Staff	$ 2,216,043	$ 2,274,379						
Total Fixed Cost	**$ 66,807,737**	**$ 74,326,085**						
Total Capital Costs	**$ 9,113,508**	**$ 12,830,778**						
Plant Capital Costs	$ 9,113,508	$ 12,830,778						
ECP Capital Costs - Coal	$ -	$ -						
ECP Capital Costs - Gas	$ -	$ -						

	Wilson Fixed O&M Costs (2015-2029 Long-Term Forecast)							
	2016	2017	2018	2019	2020	2021	2022	2023
Non-Labor Routine	$ 10,119,856	$ 10,868,088	[redacted]					
Non-Labor Outage	$ -	$ -						
Labor Plant Staff	$ 12,080,358	$ 12,364,062						
Labor Support Staff	$ 699,657	$ 715,856						
Total Fixed Cost	**$ 22,899,871**	**$ 23,948,006**						
Total Capital Costs	**$ 2,820,140**	**$ 4,237,280**						
Plant Capital Costs	$ 2,820,140	$ 4,237,280						
ECP Capital Costs - Coal	$ -	$ -						
ECP Capital Costs - Gas	$ -	$ -						

Sheet Name - Green Gas

Big Rivers Electric Corporation
Production (FDE) Costs (7-14-16)
Case No. 2018-00_____

Date: 7/12/2016

Annual Inflation Rate [redacted]

GREEN GAS

	Big Rivers Production (Net) Fixed O&M Costs (2015-2029 Long-Term Forecast)						
	2024	2025	2026	2027	2028	2029	2030
Non-Labor Routine	[redacted]						
Non-Labor Outage							
Labor Plant Staff							
Labor Support Staff							
Total Fixed Cost							
Total Capital Costs							
Plant Capital Costs							
ECP Capital Costs - Coal							
ECP Capital Costs - Gas							

	Wilson Fixed O&M Costs (2015-2029 Long-Term Forecast)						
	2024	2025	2026	2027	2028	2029	2030
Non-Labor Routine	[redacted]						
Non-Labor Outage							
Labor Plant Staff							
Labor Support Staff							
Total Fixed Cost							
Total Capital Costs							
Plant Capital Costs							
ECP Capital Costs - Coal							
ECP Capital Costs - Gas							

Sheet Name - Green Gas

Big Rivers Electric Corporation
Production (FDE) Costs (7-14-16)
Case No. 2018-00_____

Date: **7/12/2016**

Annual Inflation Rate [redacted]

GREEN GAS

	Green (Net) Fixed O&M Costs (2015-2029 Long-Term Forecast)							
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Non-Labor Routine	$ 10,232,114	$ 10,386,160	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non-Labor Outage	$ -	$ 3,328,600	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Plant Staff	$ 14,255,837	$ 14,866,003	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Support Staff	$ 741,563	$ 762,170	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Fixed Cost	**$ 25,229,514**	**$ 29,342,933**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Capital Costs	**$ 2,205,000**	**$ 5,553,000**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Plant Capital Costs	$ 2,205,000	$ 5,553,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ECP Capital Costs - Coal	$ -	$ -	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ECP Capital Costs - Gas	$ -	$ -	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

	Station II (Net)(without Reid) Fixed O&M Costs (2015-2029 Long-Term Forecast)							
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Non-Labor Routine	$ 5,355,616	$ 5,128,524	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non-Labor Outage	$ -	$ 2,479,863	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Plant Staff	$ 9,303,035	$ 9,308,084	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Support Staff	$ 774,822	$ 796,353	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Fixed Cost	**$ 15,433,473**	**$ 17,712,824**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Capital Costs	**$ 4,088,368**	**$ 3,023,498**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Plant Capital Costs	$ 4,088,368	$ 3,023,498	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ECP Capital Costs - Coal	$ -	$ -	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ECP Capital Costs - Gas	$ -	$ -	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Big Rivers Electric Corporation
Production (FDE) Costs (7-14-16)
Case No. 2018-00_____

Date: 7/12/2016

GREEN GAS

Annual Inflation Rate	[redacted]

	Green (Net) Fixed O&M Costs (2015-2029 Long-Term Forecast)						
	2024	2025	2026	2027	2028	2029	2030
Non-Labor Routine	[redacted]						
Non-Labor Outage							
Labor Plant Staff							
Labor Support Staff							
Total Fixed Cost							
Total Capital Costs							
Plant Capital Costs							
ECP Capital Costs - Coal							
ECP Capital Costs - Gas							

	Station II (Net)(without Reid) Fixed O&M Costs (2015-2029 Long-Term Forecast)						
	2024	2025	2026	2027	2028	2029	2030
Non-Labor Routine	[redacted]						
Non-Labor Outage							
Labor Plant Staff							
Labor Support Staff							
Total Fixed Cost							
Total Capital Costs							
Plant Capital Costs							
ECP Capital Costs - Coal							
ECP Capital Costs - Gas							

Big Rivers Electric Corporation
Production (FDE) Costs (7-14-16)
Case No. 2018-00______

Date: **7/12/2016**

Annual Inflation Rate [redacted]

GREEN GAS

	Reid (Net) Fixed O&M Costs (2015-2029 Long-Term Forecast)							
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Non-Labor Routine	$ 235,500	$ 236,000	[redacted]					
Non-Labor Outage	$ -	$ -	[redacted]					
Labor Plant Staff	$ -	$ -	[redacted]					
Labor Support Staff	$ -	$ -	[redacted]					
Total Fixed Cost	**$ 235,500**	**$ 236,000**	[redacted]					
Total Capital Costs	**$ -**	**$ 17,000**	[redacted]					
Plant Capital Costs	$ -	$ 17,000	[redacted]					
ECP Capital Costs - Coal	$ -	$ -	[redacted]					
ECP Capital Costs - Gas	$ -	$ -	[redacted]					

	Coleman Fixed O&M Costs (2015-2029 Long-Term Forecast)							
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Non-Labor Routine	$ 966,945	$ 995,965	[redacted]					
Non-Labor Outage	$ -	$ -	[redacted]					
Labor Plant Staff	$ 2,042,434	$ 2,090,358	[redacted]					
Labor Support Staff	$ -	$ -	[redacted]					
Total Fixed Cost	**$ 3,009,379**	**$ 3,086,323**	[redacted]					
Total Capital Costs	**$ -**	**$ -**	[redacted]					
Plant Capital Costs	$ -	$ -	[redacted]					
ECP Capital Costs - Coal	$ -	$ -	[redacted]					
ECP Capital Costs - Gas	$ -	$ -	[redacted]					

Big Rivers Electric Corporation
Production (FDE) Costs (7-14-16)
Case No. 2018-00_____

Date: **7/12/2016**

Annual Inflation Rate [redacted]

GREEN GAS

	Reid (Net) Fixed O&M Costs (2015-2029 Long-Term Forecast)						
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Non-Labor Routine	[redacted]						
Non-Labor Outage							
Labor Plant Staff							
Labor Support Staff							
Total Fixed Cost							
Total Capital Costs							
Plant Capital Costs							
ECP Capital Costs - Coal							
ECP Capital Costs - Gas							

	Coleman Fixed O&M Costs (2015-2029 Long-Term Forecast)						
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Non-Labor Routine	[redacted]						
Non-Labor Outage							
Labor Plant Staff							
Labor Support Staff							
Total Fixed Cost							
Total Capital Costs							
Plant Capital Costs							
ECP Capital Costs - Coal							
ECP Capital Costs - Gas							

Sheet Name - Green Gas

Big Rivers Electric Corporation
Production (FDE) Costs (7-14-16)
Case No. 2018-00_____

Date: **7/12/2016**

Annual Inflation Rate [redacted]

HMP&L GAS

	Big Rivers Production (Net) Fixed O&M Costs (2015-2029 Long-Term Forecast)							
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Non-Labor Routine	$ 26,910,031	$ 27,614,737	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non-Labor Outage	$ -	$ 5,808,463	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Plant Staff	$ 37,681,664	$ 38,628,506	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Support Staff	$ 2,216,043	$ 2,274,379	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Fixed Cost	**$ 66,807,737**	**$ 74,326,085**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Capital Costs	**$ 9,113,508**	**$ 12,830,778**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Plant Capital Costs	$ 9,113,508	$ 12,830,778	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ECP Capital Costs - Coal	$ -	$ -	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ECP Capital Costs - Gas	$ -	$ -	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Wilson Fixed O&M Costs (2015-2029 Long-Term Forecast)							
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Non-Labor Routine	$ 10,119,856	$ 10,868,088	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non-Labor Outage	$ -	$ -	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Plant Staff	$ 12,080,358	$ 12,364,062	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Support Staff	$ 699,657	$ 715,856	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Fixed Cost	**$ 22,899,871**	**$ 23,948,006**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Capital Costs	**$ 2,820,140**	**$ 4,237,280**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Plant Capital Costs	$ 2,820,140	$ 4,237,280	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ECP Capital Costs - Coal	$ -	$ -	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ECP Capital Costs - Gas	$ -	$ -	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Sheet Name - HMPL Gas

Big Rivers Electric Corporation
Production (FDE) Costs (7-14-16)
Case No. 2018-00______

Date:	7/12/2016	Annual Inflation Rate	[redacted]
HMP&L GAS			

	Big Rivers Production (Net) Fixed O&M Costs (2015-2029 Long-Term Forecast)						
	2024	2025	2026	2027	2028	2029	2030
Non-Labor Routine	[redacted]						
Non-Labor Outage							
Labor Plant Staff							
Labor Support Staff							
Total Fixed Cost							
Total Capital Costs							
Plant Capital Costs							
ECP Capital Costs - Coal							
ECP Capital Costs - Gas							

	Wilson Fixed O&M Costs (2015-2029 Long-Term Forecast)						
	2024	2025	2026	2027	2028	2029	2030
Non-Labor Routine	[redacted]						
Non-Labor Outage							
Labor Plant Staff							
Labor Support Staff							
Total Fixed Cost							
Total Capital Costs							
Plant Capital Costs							
ECP Capital Costs - Coal							
ECP Capital Costs - Gas							

Sheet Name - HMPL Gas

Big Rivers Electric Corporation
Production (FDE) Costs (7-14-16)
Case No. 2018-00_____

Date: **7/12/2016**

Annual Inflation Rate [redacted]

HMP&L GAS

	Green (Net) Fixed O&M Costs (2015-2029 Long-Term Forecast)							
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Non-Labor Routine	$ 10,232,114	$ 10,386,160	[redacted]					
Non-Labor Outage	$ -	$ 3,328,600	[redacted]					
Labor Plant Staff	$ 14,255,837	$ 14,866,003	[redacted]					
Labor Support Staff	$ 741,563	$ 762,170	[redacted]					
Total Fixed Cost	**$ 25,229,514**	**$ 29,342,933**	[redacted]					
Total Capital Costs	**$ 2,205,000**	**$ 5,553,000**	[redacted]					
Plant Capital Costs	$ 2,205,000	$ 5,553,000	[redacted]					
ECP Capital Costs - Coal	$ -	$ -	[redacted]					
ECP Capital Costs - Gas	$ -	$ -	[redacted]					

	Station II (Net)(without Reid) Fixed O&M Costs (2015-2029 Long-Term Forecast)							
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Non-Labor Routine	$ 5,355,616	$ 5,128,524	[redacted]					
Non-Labor Outage	$ -	$ 2,479,863	[redacted]					
Labor Plant Staff	$ 9,303,035	$ 9,308,084	[redacted]					
Labor Support Staff	$ 774,822	$ 796,353	[redacted]					
Total Fixed Cost	**$ 15,433,473**	**$ 17,712,824**	[redacted]					
Total Capital Costs	**$ 4,088,368**	**$ 3,023,498**	[redacted]					
Plant Capital Costs	$ 4,088,368	$ 3,023,498	[redacted]					
ECP Capital Costs - Coal	$ -	$ -	[redacted]					
ECP Capital Costs - Gas	$ -	$ -	[redacted]					

Sheet Name - HMPL Gas

Big Rivers Electric Corporation
Production (FDE) Costs (7-14-16)
Case No. 2018-00_____

Date: 7/12/2016

Annual Inflation Rate	[redacted]

HMP&L GAS

	Green (Net) Fixed O&M Costs (2015-2029 Long-Term Forecast)						
	2024	2025	2026	2027	2028	2029	2030
Non-Labor Routine	[redacted]						
Non-Labor Outage							
Labor Plant Staff							
Labor Support Staff							
Total Fixed Cost							
Total Capital Costs							
Plant Capital Costs							
ECP Capital Costs - Coal							
ECP Capital Costs - Gas							
	Station II (Net)(without Reid) Fixed O&M Costs (2015-2029 Long-Term Forecast)						
	2024	2025	2026	2027	2028	2029	2030
Non-Labor Routine	[redacted]						
Non-Labor Outage							
Labor Plant Staff							
Labor Support Staff							
Total Fixed Cost							
Total Capital Costs							
Plant Capital Costs							
ECP Capital Costs - Coal							
ECP Capital Costs - Gas							

Big Rivers Electric Corporation
Production (FDE) Costs (7-14-16)
Case No. 2018-00_____

Date: 7/12/2016

HMP&L GAS

Annual Inflation Rate	[redacted]

	Reid (Net) Fixed O&M Costs (2015-2029 Long-Term Forecast)							
	2016	2017	2018	2019	2020	2021	2022	2023
Non-Labor Routine	$ 235,500	$ 236,000	[redacted]					
Non-Labor Outage	$ -	$ -						
Labor Plant Staff	$ -	$ -						
Labor Support Staff	$ -	$ -						
Total Fixed Cost	**$ 235,500**	**$ 236,000**						
Total Capital Costs	**$ -**	**$ 17,000**						
Plant Capital Costs	$ -	$ 17,000						
ECP Capital Costs - Coal	$ -	$ -						
ECP Capital Costs - Gas	$ -	$ -						

	Coleman Fixed O&M Costs (2015-2029 Long-Term Forecast)							
	2016	2017	2018	2019	2020	2021	2022	2023
Non-Labor Routine	$ 966,945	$ 995,965	[redacted]					
Non-Labor Outage	$ -	$ -						
Labor Plant Staff	$ 2,042,434	$ 2,090,358						
Labor Support Staff	$ -	$ -						
Total Fixed Cost	**$ 3,009,379**	**$ 3,086,323**						
Total Capital Costs	**$ -**	**$ -**						
Plant Capital Costs	$ -	$ -						
ECP Capital Costs - Coal	$ -	$ -						
ECP Capital Costs - Gas	$ -	$ -						

Big Rivers Electric Corporation
Production (FDE) Costs (7-14-16)
Case No. 2018-00______

Date: 7/12/2016

Annual Inflation Rate [redacted]

HMP&L GAS

	Reid (Net) Fixed O&M Costs (2015-2029 Long-Term Forecast)						
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Non-Labor Routine	[redacted]						
Non-Labor Outage							
Labor Plant Staff							
Labor Support Staff							
Total Fixed Cost							
Total Capital Costs							
Plant Capital Costs							
ECP Capital Costs - Coal							
ECP Capital Costs - Gas							

	Coleman Fixed O&M Costs (2015-2029 Long-Term Forecast)						
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Non-Labor Routine	[redacted]						
Non-Labor Outage							
Labor Plant Staff							
Labor Support Staff							
Total Fixed Cost							
Total Capital Costs							
Plant Capital Costs							
ECP Capital Costs - Coal							
ECP Capital Costs - Gas							

Big Rivers Electric Corporation
Production (FDE) Costs (7-14-16)
Case No. 2018-00_____

Date: 7/12/2016

SEBREE GAS

Annual Inflation Rate [redacted]

	Big Rivers Production (Net) Fixed O&M Costs (2015-2029 Long-Term Forecast)							
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Non-Labor Routine	$ 26,910,031	$ 27,614,737	[redacted]					
Non-Labor Outage	$ -	$ 5,808,463	[redacted]					
Labor Plant Staff	$ 37,681,664	$ 38,628,506	[redacted]					
Labor Support Staff	$ 2,216,043	$ 2,274,379	[redacted]					
Total Fixed Cost	**$ 66,807,737**	**$ 74,326,085**	[redacted]					
Total Capital Costs	**$ 9,113,508**	**$ 12,830,778**	[redacted]					
Plant Capital Costs	$ 9,113,508	$ 12,830,778	[redacted]					
ECP Capital Costs - Coal	$ -	$ -	[redacted]					
ECP Capital Costs - Gas	$ -	$ -	[redacted]					
	Wilson Fixed O&M Costs (2015-2029 Long-Term Forecast)							
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Non-Labor Routine	$ 10,119,856	$ 10,868,088	[redacted]					
Non-Labor Outage	$ -	$ -	[redacted]					
Labor Plant Staff	$ 12,080,358	$ 12,364,062	[redacted]					
Labor Support Staff	$ 699,657	$ 715,856	[redacted]					
Total Fixed Cost	**$ 22,899,871**	**$ 23,948,006**	[redacted]					
Total Capital Costs	**$ 2,820,140**	**$ 4,237,280**	[redacted]					
Plant Capital Costs	$ 2,820,140	$ 4,237,280	[redacted]					
ECP Capital Costs - Coal	$ -	$ -	[redacted]					
ECP Capital Costs - Gas	$ -	$ -	[redacted]					

Big Rivers Electric Corporation
Production (FDE) Costs (7-14-16)
Case No. 2018-00_____

Date: 7/12/2016

Annual Inflation Rate [redacted]

SEBREE GAS

	Big Rivers Production (Net) Fixed O&M Costs (2015-2029 Long-Term Forecast)						
	2024	2025	2026	2027	2028	2029	2030
Non-Labor Routine	[redacted]						
Non-Labor Outage							
Labor Plant Staff							
Labor Support Staff							
Total Fixed Cost							
Total Capital Costs							
Plant Capital Costs							
ECP Capital Costs - Coal							
ECP Capital Costs - Gas							

	Wilson Fixed O&M Costs (2015-2029 Long-Term Forecast)						
	2024	2025	2026	2027	2028	2029	2030
Non-Labor Routine	[redacted]						
Non-Labor Outage							
Labor Plant Staff							
Labor Support Staff							
Total Fixed Cost							
Total Capital Costs							
Plant Capital Costs							
ECP Capital Costs - Coal							
ECP Capital Costs - Gas							

Sheet Name - Sebree Gas

Big Rivers Electric Corporation
Production (FDE) Costs (7-14-16)
Case No. 2018-00_____

Date: 7/12/2016

Annual Inflation Rate	[redacted]

SEBREE GAS

	Green (Net) Fixed O&M Costs (2015-2029 Long-Term Forecast)							
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Non-Labor Routine	$ 10,232,114	$ 10,386,160	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non-Labor Outage	$ -	$ 3,328,600	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Plant Staff	$ 14,255,837	$ 14,866,003	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Support Staff	$ 741,563	$ 762,170	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Fixed Cost	**$ 25,229,514**	**$ 29,342,933**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Capital Costs	**$ 2,205,000**	**$ 5,553,000**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Plant Capital Costs	$ 2,205,000	$ 5,553,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ECP Capital Costs - Coal	$ -	$ -	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ECP Capital Costs - Gas	$ -	$ -	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

	Station II (Net)(without Reid) Fixed O&M Costs (2015-2029 Long-Term Forecast)							
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Non-Labor Routine	$ 5,355,616	$ 5,128,524	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non-Labor Outage	$ -	$ 2,479,863	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Plant Staff	$ 9,303,035	$ 9,308,084	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Support Staff	$ 774,822	$ 796,353	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Fixed Cost	**$ 15,433,473**	**$ 17,712,824**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Capital Costs	**$ 4,088,368**	**$ 3,023,498**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Plant Capital Costs	$ 4,088,368	$ 3,023,498	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ECP Capital Costs - Coal	$ -	$ -	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ECP Capital Costs - Gas	$ -	$ -	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Sheet Name - Sebree Gas

Big Rivers Electric Corporation
Production (FDE) Costs (7-14-16)
Case No. 2018-00_____

Date: 7/12/2016

Annual Inflation Rate [redacted]

SEBREE GAS

	Green (Net) Fixed O&M Costs (2015-2029 Long-Term Forecast)						
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Non-Labor Routine	[redacted]						
Non-Labor Outage							
Labor Plant Staff							
Labor Support Staff							
Total Fixed Cost							
Total Capital Costs							
Plant Capital Costs							
ECP Capital Costs - Coal							
ECP Capital Costs - Gas							

	Station II (Net)(without Reid) Fixed O&M Costs (2015-2029 Long-Term Forecast)						
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Non-Labor Routine	[redacted]						
Non-Labor Outage							
Labor Plant Staff							
Labor Support Staff							
Total Fixed Cost							
Total Capital Costs							
Plant Capital Costs							
ECP Capital Costs - Coal							
ECP Capital Costs - Gas							

Sheet Name - Sebree Gas

Big Rivers Electric Corporation
Production (FDE) Costs (7-14-16)
Case No. 2018-00_____

Date: 7/12/2016

Annual Inflation Rate [redacted]

SEBREE GAS

	Reid (Net) Fixed O&M Costs (2015-2029 Long-Term Forecast)							
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Non-Labor Routine	$ 235,500	$ 236,000	[redacted]					
Non-Labor Outage	$ -	$ -						
Labor Plant Staff	$ -	$ -						
Labor Support Staff	$ -	$ -						
Total Fixed Cost	**$ 235,500**	**$ 236,000**						
Total Capital Costs	**$ -**	**$ 17,000**						
Plant Capital Costs	$ -	$ 17,000						
ECP Capital Costs - Coal	$ -	$ -						
ECP Capital Costs - Gas	$ -	$ -						

	Coleman Fixed O&M Costs (2015-2029 Long-Term Forecast)							
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Non-Labor Routine	$ 966,945	$ 995,965	[redacted]					
Non-Labor Outage	$ -	$ -						
Labor Plant Staff	$ 2,042,434	$ 2,090,358						
Labor Support Staff	$ -	$ -						
Total Fixed Cost	**$ 3,009,379**	**$ 3,086,323**						
Total Capital Costs	**$ -**	**$ -**						
Plant Capital Costs	$ -	$ -						
ECP Capital Costs - Coal	$ -	$ -						
ECP Capital Costs - Gas	$ -	$ -						

Sheet Name - Sebree Gas

Big Rivers Electric Corporation
Production (FDE) Costs (7-14-16)
Case No. 2018-00_____

Date: 7/12/2016

Annual Inflation Rate	[redacted]

SEBREE GAS

	Reid (Net) Fixed O&M Costs (2015-2029 Long-Term Forecast)						
	2024	2025	2026	2027	2028	2029	2030
Non-Labor Routine	[redacted]						
Non-Labor Outage							
Labor Plant Staff							
Labor Support Staff							
Total Fixed Cost							
Total Capital Costs							
Plant Capital Costs							
ECP Capital Costs - Coal							
ECP Capital Costs - Gas							

	Coleman Fixed O&M Costs (2015-2029 Long-Term Forecast)						
	2024	2025	2026	2027	2028	2029	2030
Non-Labor Routine	[redacted]						
Non-Labor Outage							
Labor Plant Staff							
Labor Support Staff							
Total Fixed Cost							
Total Capital Costs							
Plant Capital Costs							
ECP Capital Costs - Coal							
ECP Capital Costs - Gas							

Big Rivers Electric Corporation
Production (FDE) Costs (7-14-16)
Case No. 2018-00_____

Date: **7/12/2016**

Annual Inflation Rate [redacted]

GREEN CO-FIRING

	Big Rivers Production (Net) Fixed O&M Costs (2015-2029 Long-Term Forecast)							
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Non-Labor Routine	$ 26,910,031	$ 27,614,737	[redacted]					
Non-Labor Outage	$ -	$ 5,808,463	[redacted]					
Labor Plant Staff	$ 37,681,664	$ 38,628,506	[redacted]					
Labor Support Staff	$ 2,216,043	$ 2,274,379	[redacted]					
Total Fixed Cost	**$ 66,807,737**	**$ 74,326,085**	[redacted]					
Total Capital Costs	**$ 9,113,508**	**$ 12,830,778**	[redacted]					
Plant Capital Costs	$ 9,113,508	$ 12,830,778	[redacted]					
ECP Capital Costs - Coal	$ -	$ -	[redacted]					
ECP Capital Costs - Gas	$ -	$ -	[redacted]					

	Wilson Fixed O&M Costs (2015-2029 Long-Term Forecast)							
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Non-Labor Routine	$ 10,119,856	$ 10,868,088	[redacted]					
Non-Labor Outage	$ -	$ -	[redacted]					
Labor Plant Staff	$ 12,080,358	$ 12,364,062	[redacted]					
Labor Support Staff	$ 699,657	$ 715,856	[redacted]					
Total Fixed Cost	**$ 22,899,871**	**$ 23,948,006**	[redacted]					
Total Capital Costs	**$ 2,820,140**	**$ 4,237,280**	[redacted]					
Plant Capital Costs	$ 2,820,140	$ 4,237,280	[redacted]					
ECP Capital Costs - Coal	$ -	$ -	[redacted]					
ECP Capital Costs - Gas	$ -	$ -	[redacted]					

Big Rivers Electric Corporation
Production (FDE) Costs (7-14-16)
Case No. 2018-00______

Date: 7/12/2016

Annual Inflation Rate	[redacted]

GREEN CO-FIRING

	Big Rivers Production (Net) Fixed O&M Costs (2015-2029 Long-Term Forecast)						
	2024	2025	2026	2027	2028	2029	2030
Non-Labor Routine	[redacted]						
Non-Labor Outage							
Labor Plant Staff							
Labor Support Staff							
Total Fixed Cost							
Total Capital Costs							
Plant Capital Costs							
ECP Capital Costs - Coal							
ECP Capital Costs - Gas							

	Wilson Fixed O&M Costs (2015-2029 Long-Term Forecast)						
	2024	2025	2026	2027	2028	2029	2030
Non-Labor Routine	[redacted]						
Non-Labor Outage							
Labor Plant Staff							
Labor Support Staff							
Total Fixed Cost							
Total Capital Costs							
Plant Capital Costs							
ECP Capital Costs - Coal							
ECP Capital Costs - Gas							

Sheet Name - Green Co-Firing

Big Rivers Electric Corporation
Production (FDE) Costs (7-14-16)
Case No. 2018-00_____

Date: 7/12/2016

GREEN CO-FIRING

Annual Inflation Rate	[redacted]

	Green (Net) Fixed O&M Costs (2015-2029 Long-Term Forecast)							
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Non-Labor Routine	$ 10,232,114	$ 10,386,160	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non-Labor Outage	$ -	$ 3,328,600	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Plant Staff	$ 14,255,837	$ 14,866,003	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Support Staff	$ 741,563	$ 762,170	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Fixed Cost	**$ 25,229,514**	**$ 29,342,933**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Capital Costs	**$ 2,205,000**	**$ 5,553,000**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Plant Capital Costs	$ 2,205,000	$ 5,553,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ECP Capital Costs - Coal	$ -	$ -	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ECP Capital Costs - Gas	$ -	$ -	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

	Station II (Net)(without Reid) Fixed O&M Costs (2015-2029 Long-Term Forecast)							
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Non-Labor Routine	$ 5,355,616	$ 5,128,524	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non-Labor Outage	$ -	$ 2,479,863	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Plant Staff	$ 9,303,035	$ 9,308,084	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Support Staff	$ 774,822	$ 796,353	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Fixed Cost	**$ 15,433,473**	**$ 17,712,824**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Capital Costs	**$ 4,088,368**	**$ 3,023,498**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Plant Capital Costs	$ 4,088,368	$ 3,023,498	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ECP Capital Costs - Coal	$ -	$ -	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ECP Capital Costs - Gas	$ -	$ -	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Sheet Name - Green Co-Firing

Big Rivers Electric Corporation
Production (FDE) Costs (7-14-16)
Case No. 2018-00_____

Date: 7/12/2016

Annual Inflation Rate [redacted]

GREEN CO-FIRING

	Green (Net) Fixed O&M Costs (2015-2029 Long-Term Forecast)						
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Non-Labor Routine	[redacted]						
Non-Labor Outage							
Labor Plant Staff							
Labor Support Staff							
Total Fixed Cost							
Total Capital Costs							
Plant Capital Costs							
ECP Capital Costs - Coal							
ECP Capital Costs - Gas							

	Station II (Net)(without Reid) Fixed O&M Costs (2015-2029 Long-Term Forecast)						
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Non-Labor Routine	[redacted]						
Non-Labor Outage							
Labor Plant Staff							
Labor Support Staff							
Total Fixed Cost							
Total Capital Costs							
Plant Capital Costs							
ECP Capital Costs - Coal							
ECP Capital Costs - Gas							

Big Rivers Electric Corporation
Production (FDE) Costs (7-14-16)
Case No. 2018-00_____

Date: 7/12/2016

Annual Inflation Rate [redacted]

GREEN CO-FIRING

	Reid (Net) Fixed O&M Costs (2015-2029 Long-Term Forecast)							
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Non-Labor Routine	$ 235,500	$ 236,000	[redacted]					
Non-Labor Outage	$ -	$ -	[redacted]					
Labor Plant Staff	$ -	$ -	[redacted]					
Labor Support Staff	$ -	$ -	[redacted]					
Total Fixed Cost	**$ 235,500**	**$ 236,000**	[redacted]					
Total Capital Costs	**$ -**	**$ 17,000**	[redacted]					
Plant Capital Costs	$ -	$ 17,000	[redacted]					
ECP Capital Costs - Coal	$ -	$ -	[redacted]					
ECP Capital Costs - Gas	$ -	$ -	[redacted]					

	Coleman Fixed O&M Costs (2015-2029 Long-Term Forecast)							
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Non-Labor Routine	$ 966,945	$ 995,965	[redacted]					
Non-Labor Outage	$ -	$ -	[redacted]					
Labor Plant Staff	$ 2,042,434	$ 2,090,358	[redacted]					
Labor Support Staff	$ -	$ -	[redacted]					
Total Fixed Cost	**$ 3,009,379**	**$ 3,086,323**	[redacted]					
Total Capital Costs	**$ -**	**$ -**	[redacted]					
Plant Capital Costs	$ -	$ -	[redacted]					
ECP Capital Costs - Coal	$ -	$ -	[redacted]					
ECP Capital Costs - Gas	$ -	$ -	[redacted]					

Sheet Name - Green Co-Firing

Big Rivers Electric Corporation
Production (FDE) Costs (7-14-16)
Case No. 2018-00______

Date: 7/12/2016

Annual Inflation Rate	[redacted]

GREEN CO-FIRING

	Reid (Net) Fixed O&M Costs (2015-2029 Long-Term Forecast)						
	2024	2025	2026	2027	2028	2029	2030
Non-Labor Routine	[redacted]						
Non-Labor Outage							
Labor Plant Staff							
Labor Support Staff							
Total Fixed Cost							
Total Capital Costs							
Plant Capital Costs							
ECP Capital Costs - Coal							
ECP Capital Costs - Gas							

	Coleman Fixed O&M Costs (2015-2029 Long-Term Forecast)						
	2024	2025	2026	2027	2028	2029	2030
Non-Labor Routine	[redacted]						
Non-Labor Outage							
Labor Plant Staff							
Labor Support Staff							
Total Fixed Cost							
Total Capital Costs							
Plant Capital Costs							
ECP Capital Costs - Coal							
ECP Capital Costs - Gas							

Sheet Name - Green Co-Firing

Big Rivers Electric Corporation
Production (FDE) Costs (7-14-16)
Case No. 2018-00_____

Date: 7/12/2016

Annual Inflation Rate	[redacted]

STA. II EXIT

	Big Rivers Production (Net - Gross beginning 2019) Fixed O&M Costs (2015-2029 Long-Term Forecast)							
	2016	2017	2018	2019	2020	2021	2022	2023
Non-Labor Routine	$ 26,910,031	$ 27,614,737	[redacted]					
Non-Labor Outage	$ -	$ 5,808,463						
Labor Plant Staff	$ 37,681,664	$ 38,628,506						
Labor Support Staff	$ 2,216,043	$ 2,274,379						
Total Fixed Cost	**$ 66,807,737**	**$ 74,326,085**						
Total Capital Costs	**$ 9,113,508**	**$ 12,830,778**						
Plant Capital Costs	$ 9,113,508	$ 12,830,778						
ECP Capital Costs - Coal	$ -	$ -						
ECP Capital Costs - Gas	$ -	$ -						

	Wilson Fixed O&M Costs (2015-2029 Long-Term Forecast)							
	2016	2017	2018	2019	2020	2021	2022	2023
Non-Labor Routine	$ 10,119,856	$ 10,868,088	[redacted]					
Non-Labor Outage	$ -	$ -						
Labor Plant Staff	$ 12,080,358	$ 12,364,062						
Labor Support Staff	$ 699,657	$ 715,856						
Total Fixed Cost	**$ 22,899,871**	**$ 23,948,006**						
Total Capital Costs	**$ 2,820,140**	**$ 4,237,280**						
Plant Capital Costs	$ 2,820,140	$ 4,237,280						
ECP Capital Costs - Coal	$ -	$ -						
ECP Capital Costs - Gas	$ -	$ -						

Sheet Name - Sta II Exit

Big Rivers Electric Corporation
Production (FDE) Costs (7-14-16)
Case No. 2018-00_____

Date: 7/12/2016

Annual Inflation Rate [redacted]

STA. II EXIT

	Big Rivers Production (Net - Gross beginning 2019) Fixed O&M Costs (2015-2029 Long-Term Forecast)						
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Non-Labor Routine	[redacted]						
Non-Labor Outage							
Labor Plant Staff							
Labor Support Staff							
Total Fixed Cost							
Total Capital Costs							
Plant Capital Costs							
ECP Capital Costs - Coal							
ECP Capital Costs - Gas							

	Wilson Fixed O&M Costs (2015-2029 Long-Term Forecast)						
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Non-Labor Routine	[redacted]						
Non-Labor Outage							
Labor Plant Staff							
Labor Support Staff							
Total Fixed Cost							
Total Capital Costs							
Plant Capital Costs							
ECP Capital Costs - Coal							
ECP Capital Costs - Gas							

Sheet Name - Sta II Exit

Big Rivers Electric Corporation
Production (FDE) Costs (7-14-16)
Case No. 2018-00_____

Date: **7/12/2016**

Annual Inflation Rate [redacted]

STA. II EXIT

	Green (Net - Gross beginning 2019) Fixed O&M Costs (2015-2029 Long-Term Forecast)							
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Non-Labor Routine	$ 10,232,114	$ 10,386,160	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non-Labor Outage	$ -	$ 3,328,600	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Plant Staff	$ 14,255,837	$ 14,866,003	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Support Staff	$ 741,563	$ 762,170	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Fixed Cost	**$ 25,229,514**	**$ 29,342,933**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Capital Costs	**$ 2,205,000**	**$ 5,553,000**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Plant Capital Costs	$ 2,205,000	$ 5,553,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ECP Capital Costs - Coal	$ -	$ -	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ECP Capital Costs - Gas	$ -	$ -	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

	Station II (Net)(without Reid) Fixed O&M Costs (2015-2029 Long-Term Forecast)							
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Non-Labor Routine	$ 5,355,616	$ 5,128,524	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non-Labor Outage	$ -	$ 2,479,863	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Plant Staff	$ 9,303,035	$ 9,308,084	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Support Staff	$ 774,822	$ 796,353	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Fixed Cost	**$ 15,433,473**	**$ 17,712,824**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Capital Costs	**$ 4,088,368**	**$ 3,023,498**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Plant Capital Costs	$ 4,088,368	$ 3,023,498	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ECP Capital Costs - Coal	$ -	$ -	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ECP Capital Costs - Gas	$ -	$ -	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Sheet Name - Sta II Exit

Big Rivers Electric Corporation
Production (FDE) Costs (7-14-16)
Case No. 2018-00_____

Date: 7/12/2016

STA. II EXIT

Annual Inflation Rate	[redacted]

	Green (Net - Gross beginning 2019) Fixed O&M Costs (2015-2029 Long-Term Forecast)						
	2024	2025	2026	2027	2028	2029	2030
Non-Labor Routine	[redacted]						
Non-Labor Outage							
Labor Plant Staff							
Labor Support Staff							
Total Fixed Cost							
Total Capital Costs							
Plant Capital Costs							
ECP Capital Costs - Coal							
ECP Capital Costs - Gas							

	Station II (Net)(without Reid) Fixed O&M Costs (2015-2029 Long-Term Forecast)						
	2024	2025	2026	2027	2028	2029	2030
Non-Labor Routine	[redacted]						
Non-Labor Outage							
Labor Plant Staff							
Labor Support Staff							
Total Fixed Cost							
Total Capital Costs							
Plant Capital Costs							
ECP Capital Costs - Coal							
ECP Capital Costs - Gas							

Big Rivers Electric Corporation
Production (FDE) Costs (7-14-16)
Case No. 2018-00______

Date: 7/12/2016

STA. II EXIT

Annual Inflation Rate	[redacted]

	Reid (Net - Gross beginning 2019) Fixed O&M Costs (2015-2029 Long-Term Forecast)							
	2016	2017	2018	2019	2020	2021	2022	2023
Non-Labor Routine	$ 235,500	$ 236,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non-Labor Outage	$ -	$ -	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Plant Staff	$ -	$ -	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Support Staff	$ -	$ -	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Fixed Cost	**$ 235,500**	**$ 236,000**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Capital Costs	**$ -**	**$ 17,000**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Plant Capital Costs	$ -	$ 17,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ECP Capital Costs - Coal	$ -	$ -	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ECP Capital Costs - Gas	$ -	$ -	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

	Coleman Fixed O&M Costs (2015-2029 Long-Term Forecast)							
	2016	2017	2018	2019	2020	2021	2022	2023
Non-Labor Routine	$ 966,945	$ 995,965	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non-Labor Outage	$ -	$ -	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Plant Staff	$ 2,042,434	$ 2,090,358	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Support Staff	$ -	$ -	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Fixed Cost	**$ 3,009,379**	**$ 3,086,323**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Capital Costs	**$ -**	**$ -**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Plant Capital Costs	$ -	$ -	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ECP Capital Costs - Coal	$ -	$ -	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ECP Capital Costs - Gas	$ -	$ -	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Sheet Name - Sta II Exit

Big Rivers Electric Corporation
Production (FDE) Costs (7-14-16)
Case No. 2018-00_____

Date: 7/12/2016

Annual Inflation Rate [redacted]

STA. II EXIT

	Reid (Net - Gross beginning 2019) Fixed O&M Costs (2015-2029 Long-Term Forecast)						
	2024	2025	2026	2027	2028	2029	2030
Non-Labor Routine	[redacted]						
Non-Labor Outage							
Labor Plant Staff							
Labor Support Staff							
Total Fixed Cost							
Total Capital Costs							
Plant Capital Costs							
ECP Capital Costs - Coal							
ECP Capital Costs - Gas							

	Coleman Fixed O&M Costs (2015-2029 Long-Term Forecast)						
	2024	2025	2026	2027	2028	2029	2030
Non-Labor Routine	[redacted]						
Non-Labor Outage							
Labor Plant Staff							
Labor Support Staff							
Total Fixed Cost							
Total Capital Costs							
Plant Capital Costs							
ECP Capital Costs - Coal							
ECP Capital Costs - Gas							

Big Rivers Electric Corporation
Production (FDE) Costs (7-14-16)
Case No. 2018-00_____

Date: **7/14/2016**

	ECP Capital Costs (Net) - Base					
	2016	2017	2018	2019	2020	2021
Wilson	$ -	$ -	[redacted]			
Green Coal	$ -	$ -				
Green Gas	$ -	$ -				
Station II (Net) Coal	$ -	$ -				
Station II (Net) Gas	$ -	$ -				
Reid - 316b	$ -	$ -				
Coleman Idle - Ponds	$ -	$ -				
Coleman Gas	$ -	$ -				
Big Rivers (Net)	**$ -**	**$ -**				
Cumulative Total	**$ -**	**$ -**				

	Green Station Gas Conversion					
	2016	2017	2018	2019	2020	2021
Wilson	$ -	$ -	[redacted]			
Green Coal - Ponds	$ -	$ -				
Green Gas	$ -	$ -				
Station II (Net) Coal	$ -	$ -				
Station II (Net) Gas						
Reid	$ -	$ -				
Coleman Idle - Ponds	$ -	$ -				
Coleman Gas	$ -	$ -				
Big Rivers (Net)	**$ -**	**$ -**				
Cumulative Total	**$ -**	**$ -**				

Sheet Name - ECP Capital

Big Rivers Electric Corporation
Production (FDE) Costs (7-14-16)
Case No. 2018-00______

Date: **Date:** **7/14/2016**

	ECP Capital Costs (Net) - Base					
	2022	2023	2024	2025	2026	Total
Wilson	[redacted]					
Green Coal						
Green Gas						
Station II (Net) Coal						
Station II (Net) Gas						
Reid - 316b						
Coleman Idle - Ponds						
Coleman Gas						
Big Rivers (Net)						
Cumulative Total						

	Green Station Gas Conversion					
	2022	2023	2024	2025	2026	Total
Wilson	[redacted]					
Green Coal - Ponds						
Green Gas						
Station II (Net) Coal						
Station II (Net) Gas						
Reid						
Coleman Idle - Ponds						
Coleman Gas						
Big Rivers (Net)						
Cumulative Total						

Sheet Name - ECP Capital

Big Rivers Electric Corporation
Production (FDE) Costs (7-14-16)
Case No. 2018-00_____

Date: **7/14/2016**

	HMP&L Station 2 Gas Conversion					
	2016	**2017**	**2018**	**2019**	**2020**	**2021**
Wilson	$ -	$ -	[redacted]			
Green Coal - Ponds	$ -	$ -				
Green Gas	$ -	$ -				
Station II (Net) Coal	$ -	$ -				
Station II (Net) Gas	$ -	$ -				
Reid	$ -	$ -				
Coleman Idle - Ponds	$ -	$ -				
Coleman Gas	$ -	$ -				
Big Rivers (Net)	**$ -**	**$ -**				
Cumulative Total	**$ -**	**$ -**				

	Sebree Station Gas Conversion					
	2016	**2017**	**2018**	**2019**	**2020**	**2021**
Wilson	$ -	$ -	[redacted]			
Green Coal - Ponds	$ -	$ -				
Green Gas	$ -	$ -				
Station II (Net) Ponds	$ -	$ -				
Station II (Net) Gas	$ -	$ -				
Reid	$ -	$ -				
Coleman Idle - Ponds	$ -	$ -				
Coleman Gas	$ -	$ -				
Big Rivers (Net)	**$ -**	**$ -**				
Cumulative Total	**$ -**	**$ -**				

Big Rivers Electric Corporation
Production (FDE) Costs (7-14-16)
Case No. 2018-00_____

Date: **Date:** **7/14/2016**

	HMP&L Station 2 Gas Conversion					
	2022	**2023**	**2024**	**2025**	**2026**	**Total**
Wilson	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Green Coal - Ponds	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Green Gas	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Station II (Net) Coal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Station II (Net) Gas	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Reid	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Coleman Idle - Ponds	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Coleman Gas	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Big Rivers (Net)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cumulative Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

	Sebree Station Gas Conversion					
	2022	**2023**	**2024**	**2025**	**2026**	**Total**
Wilson	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Green Coal - Ponds	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Green Gas	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Station II (Net) Ponds	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Station II (Net) Gas	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Reid	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Coleman Idle - Ponds	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Coleman Gas	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Big Rivers (Net)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cumulative Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Big Rivers Electric Corporation
Production (FDE) Costs (7-14-16)
Case No. 2018-00_____

Date: 7/14/2016

	Green Co-Firing (Coal or Natural Gas)					
	2016	**2017**	**2018**	**2019**	**2020**	**2021**
Wilson	$ -	$ -	[redacted]			
Green Coal	$ -	$ -	[redacted]			
Green Gas	$ -	$ -	[redacted]			
Station II (Net) Coal	$ -	$ -	[redacted]			
Station II (Net) Gas			[redacted]			
Reid	$ -	$ -	[redacted]			
Coleman Idle - Ponds	$ -	$ -	[redacted]			
Coleman Gas	$ -	$ -	[redacted]			
Big Rivers (Net)	**$ -**	**$ -**	[redacted]			
Cumulative Total	**$ -**	**$ -**	[redacted]			

	Station II Exit in 2018					
	2016	**2017**	**2018**	**2019**	**2020**	**2021**
Wilson	$ -	$ -	[redacted]			
Green Coal	$ -	$ -	[redacted]			
Green Gas	$ -	$ -	[redacted]			
Station II (Net) Coal	$ -	$ -	[redacted]			
Station II (Net) Gas			[redacted]			
Reid	$ -	$ -	[redacted]			
Coleman Idle - Ponds	$ -	$ -	[redacted]			
Coleman Gas	$ -	$ -	[redacted]			
Big Rivers (Net)	**$ -**	**$ -**	[redacted]			
Cumulative Total	**$ -**	**$ -**	[redacted]			

Big Rivers Electric Corporation
Production (FDE) Costs (7-14-16)
Case No. 2018-00_____

Date: Date: 7/14/2016

	Green Co-Firing (Coal or Natural Gas)					
	2022	2023	2024	2025	2026	Total
Wilson	[redacted]					
Green Coal						
Green Gas						
Station II (Net) Coal						
Station II (Net) Gas						
Reid						
Coleman Idle - Ponds						
Coleman Gas						
Big Rivers (Net)						
Cumulative Total						

	Station II Exit in 2018					
	2022	2023	2024	2025	2026	Total
Wilson	[redacted]					
Green Coal						
Green Gas						
Station II (Net) Coal						
Station II (Net) Gas						
Reid						
Coleman Idle - Ponds						
Coleman Gas						
Big Rivers (Net)						
Cumulative Total						

Big Rivers Electric Corporation
Production (FDE) Costs (7-14-16)
Case No. 2018-00_____

Date: **7/14/2016**

	2016	2017	2018	2019	2020	2021
Wilson Coal	$ -	$ -	[redacted]			
Green Coal	$ -	$ -				
Green Gas	$ -	$ -				
Green Idle - Ponds	$ -	$ -				
Sta II Coal	$ -	$ -				
Sta II Gas	$ -	$ -				
Sta II Ponds	$ -	$ -				
Reid	$ -	$ -				
Coleman Idle - Ponds	$ -	$ -				
Coleman Gas	$ -	$ -				
Coleman Gas - 316b						

Big Rivers Electric Corporation
Production (FDE) Costs (7-14-16)
Case No. 2018-00______

Date: **Date:** **7/14/2016**

	2022	2023	2024	2025	2026	Total
Wilson Coal	[redacted]					
Green Coal						
Green Gas						
Green Idle - Ponds						
Sta II Coal						
Sta II Gas						
Sta II Ponds						
Reid						
Coleman Idle - Ponds						
Coleman Gas						
Coleman Gas - 316b						

Sheet Name - ECP Capital

2016 - 2030 Planned Outage Schedule (Outage Forecast May 2016)								
Year	**Green Unit 1**	**Green Unit 2**	**HMP&L (Station Two) Unit 1**	**HMP&L (Station Two) Unit 2**	**Wilson Unit 1**	**Reid Unit 1**	**Reid Combustion Turbine**	**System Total**
2017		504	600					**1,104**
2018	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			[redacted]
2019	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			[redacted]
2020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			[redacted]
2021	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			[redacted]
2029	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			[redacted]
2030	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			[redacted]

Note(s) - 1.- Outages due to Turbine Overhauls are as follows:

[redacted]

Big Rivers Electric Corporation
Forecast Metrics - Budget versus HMPL Exit - 11-21-2017
Case No. 2018-00_____

2018-2031 Forecast Summary

	2018	2019	2020	2021	2022	2023	2024
Net Margins ($ Millions) - HMPL Exit	[redacted]						
Net Margins ($ Millions) - Current Budget							
Capital ($ Millions) - HMPL Exit							
Capital ($ Millions) - Current Budget							
TIER - HMPL Exit							
TIER - Current Budget							
North Star - HMPL Exit							
North Star - Current Budget							
Ending Cash Balance (In Millions $) - HMPL Exit							
Ending Cash Balance (In Millions $) - Current Budget							
Debt Service Coverage Ratio - HMPL Exit							
Debt Service Coverage Ratio - Current Budget							

Big Rivers Electric Corporation
Forecast Metrics - Budget versus HMPL Exit - 11-21-2017
Case No. 2018-00_____

2018-2031 Forecast Summary

	2025	2026	2027	2028	2029	2030	2031	2019-2030
Net Margins ($ Millions) - HMPL Exit	[redacted]							[redacted]
Net Margins ($ Millions) - Current Budget	[redacted]							[redacted]
Capital ($ Millions) - HMPL Exit	[redacted]							[redacted]
Capital ($ Millions) - Current Budget	[redacted]							[redacted]
TIER - HMPL Exit	[redacted]							[redacted]
TIER - Current Budget	[redacted]							[redacted]
North Star - HMPL Exit	[redacted]							[redacted]
North Star - Current Budget	[redacted]							[redacted]
Ending Cash Balance (In Millions $) - HMPL Exit	[redacted]							[redacted]
Ending Cash Balance (In Millions $) - Current Budget	[redacted]							[redacted]
Debt Service Coverage Ratio - HMPL Exit	[redacted]							[redacted]
Debt Service Coverage Ratio - Current Budget	[redacted]							[redacted]

Big Rivers Electric Corporation
Forecast Metrics - Budget versus HMPL Exit - 11-21-2017
Case No. 2018-00_____

2018-2031 Forecast Summary

	2018	2019	2020	2021	2022	2023	2024
Non-Member/Market Revenue ($ millions) - HMPL Exit	[redacted]						
Non-Member/Market Revenue ($ millions) - Current Budget	[redacted]						
Wholesale Rural Base Rate $/MWh - HMPL Exit	[redacted]						
Wholesale Rural Base Rate $/MWh - Current Budget	[redacted]						
Wholesale Rural Rate "All-In" (Net) $/MWh - HMPL Exit	[redacted]						
Wholesale Rural Rate "All-In" (Net) $/MWh - Current Budget	[redacted]						
Wholesale Large Industrial Base Rate $/MWh - HMPL Exit	[redacted]						
Wholesale Large Industrial Base Rate $/MWh - Current Budget	[redacted]						
Wholesale Large Industrial Rate "All-In" (Net) $/MWh - HMPL Exit	[redacted]						
Wholesale Large Industrial Rate "All-In" (Net) $/MWh - Current Budget	[redacted]						

Big Rivers Electric Corporation
Forecast Metrics - Budget versus HMPL Exit - 11-21-2017
Case No. 2018-00_____

2018-2031 Forecast Summary

	2025	2026	2027	2028	2029	2030	2031	2019-2030
Non-Member/Market Revenue ($ millions) - HMPL Exit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non-Member/Market Revenue ($ millions) - Current Budget	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Wholesale Rural Base Rate $/MWh - HMPL Exit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Wholesale Rural Base Rate $/MWh - Current Budget	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Wholesale Rural Rate "All-In" (Net) $/MWh - HMPL Exit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Wholesale Rural Rate "All-In" (Net) $/MWh - Current Budget	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Wholesale Large Industrial Base Rate $/MWh - HMPL Exit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Wholesale Large Industrial Base Rate $/MWh - Current Budget	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Wholesale Large Industrial Rate "All-In" (Net) $/MWh - HMPL Exit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Wholesale Large Industrial Rate "All-In" (Net) $/MWh - Current Budget	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Sheet Name - Summary

Big Rivers Electric Corporation
Forecast Metrics - Budget vs HMPL Exit - 11-21-2017
Case No. 2018-00______

Budget vs HMPL Exit 11-21-2017

		2018	2019	2020	2021	2022	2023	2024
Net Margins ($ Millions)	HMPL Exit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Budget	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Budget vs HMPL Exit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital ($ Millions)	HMPL Exit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Budget	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Budget vs HMPL Exit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
TIER	HMPL Exit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Budget	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Budget vs HMPL Exit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
North Star ($/kWh)	HMPL Exit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Budget	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Budget vs HMPL Exit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ending Cash Balance ($ Millions)	HMPL Exit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Budget	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Budget vs HMPL Exit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Sheet Name - Conditional Format

Big Rivers Electric Corporation
Forecast Metrics - Budget vs HMPL Exit - 11-21-2017
Case No. 2018-00______

Budget vs HMPL Exit 11-21-2017

		2025	2026	2027	2028	2029	2030
Net Margins ($ Millions)	HMPL Exit	[redacted]					
	Budget	[redacted]					
		[redacted]					
	Budget vs HMPL Exit	[redacted]					
		[redacted]					
Capital ($ Millions)	HMPL Exit	[redacted]					
	Budget	[redacted]					
		[redacted]					
	Budget vs HMPL Exit	[redacted]					
		[redacted]					
TIER	HMPL Exit	[redacted]					
	Budget	[redacted]					
		[redacted]					
	Budget vs HMPL Exit	[redacted]					
		[redacted]					
North Star ($/kWh)	HMPL Exit	[redacted]					
	Budget	[redacted]					
		[redacted]					
	Budget vs HMPL Exit	[redacted]					
		[redacted]					
Ending Cash Balance ($ Millions)	HMPL Exit	[redacted]					
	Budget	[redacted]					
		[redacted]					
	Budget vs HMPL Exit	[redacted]					
		[redacted]					

Sheet Name - Conditional Format

Big Rivers Electric Corporation
Forecast Metrics - Budget vs HMPL Exit - 11-21-2017
Case No. 2018-00_____

Budget vs HMPL Exit 11-21-2017

		2018	2019	2020	2021	2022	2023	2024
CFC Equity Requirement, Over / (Under) ($ Millions)	HMPL Exit	[redacted]						
	Budget							
	Budget vs HMPL Exit							
Equity ($ Millions)	HMPL Exit							
	Budget							
	Budget vs HMPL Exit							
Debt ($ Millions)	HMPL Exit							
	Budget							
	Budget vs HMPL Exit							
Debt Service Coverage Ratio	HMPL Exit							
	Budget							
	Budget vs HMPL Exit							
Off System Excluding Capacity ($/MWh)	HMPL Exit							
	Budget							
	Budget vs HMPL Exit							

Sheet Name - Conditional Format

Big Rivers Electric Corporation
Forecast Metrics - Budget vs HMPL Exit - 11-21-2017
Case No. 2018-00_____

Budget vs HMPL Exit 11-21-2017

		2025	2026	2027	2028	2029	2030
CFC Equity Requirement, Over / (Under) ($ Millions)	HMPL Exit	[redacted]					
	Budget	[redacted]					
		[redacted]					
	Budget vs HMPL Exit	[redacted]					
		[redacted]					
Equity ($ Millions)	HMPL Exit	[redacted]					
	Budget	[redacted]					
		[redacted]					
	Budget vs HMPL Exit	[redacted]					
		[redacted]					
Debt ($ Millions)	HMPL Exit	[redacted]					
	Budget	[redacted]					
		[redacted]					
	Budget vs HMPL Exit	[redacted]					
		[redacted]					
Debt Service Coverage Ratio	HMPL Exit	[redacted]					
	Budget	[redacted]					
		[redacted]					
	Budget vs HMPL Exit	[redacted]					
		[redacted]					
Off System Excluding Capacity ($/MWh)	HMPL Exit	[redacted]					
	Budget	[redacted]					
		[redacted]					
	Budget vs HMPL Exit	[redacted]					
		[redacted]					

Sheet Name - Conditional Format

Big Rivers Electric Corporation
Forecast Metrics - Budget vs HMPL Exit - 11-21-2017
Case No. 2018-00_____

Budget vs HMPL Exit 11-21-2017

		2018	2019	2020	2021	2022	2023	2024
Non Member Market Revenue ($ Millions)	HMPL Exit	[redacted]						
	Budget							
	Budget vs HMPL Exit							
Capacity Sold (MW)	HMPL Exit							
	Budget							
	Budget vs HMPL Exit							
Capacity Revenue ($ Millions)	HMPL Exit							
	Budget							
	Budget vs HMPL Exit							
Wholesale Rural "All In" Rate ($/MWh)	HMPL Exit							
	Budget							
	Budget vs HMPL Exit							
Wholesale Large Industrial "All In" Rate ($/MWh)	HMPL Exit							
	Budget							
	Budget vs HMPL Exit							

Sheet Name - Conditional Format

Big Rivers Electric Corporation
Forecast Metrics - Budget vs HMPL Exit - 11-21-2017
Case No. 2018-00______

Budget vs HMPL Exit 11-21-2017

		2025	2026	2027	2028	2029	2030
Non Member Market Revenue ($ Millions)	HMPL Exit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Budget	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Budget vs HMPL Exit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capacity Sold (MW)	HMPL Exit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Budget	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Budget vs HMPL Exit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capacity Revenue ($ Millions)	HMPL Exit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Budget	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Budget vs HMPL Exit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Wholesale Rural "All In" Rate ($/MWh)	HMPL Exit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Budget	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Budget vs HMPL Exit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Wholesale Large Industrial "All In" Rate ($/MWh)	HMPL Exit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Budget	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Budget vs HMPL Exit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Sheet Name - Conditional Format

Big Rivers Electric Corporation
Forecast Metrics - Budget vs HMPL Exit - 11-21-2017
Case No. 2018-00_____

Budget vs HMPL Exit 11-21-2017

		2018	2019	2020	2021	2022	2023	2024
Wholesale Rural Revenue ($ Millions)	HMPL Exit	[redacted]						
	Budget	[redacted]						
		[redacted]						
	Budget vs HMPL Exit	[redacted]						
		[redacted]						
Wholesale Large Industrial Revenue ($ Millions)	HMPL Exit	[redacted]						
	Budget	[redacted]						
		[redacted]						
	Budget vs HMPL Exit	[redacted]						

Sheet Name - Conditional Format

Big Rivers Electric Corporation
Forecast Metrics - Budget vs HMPL Exit - 11-21-2017
Case No. 2018-00_____

Budget vs HMPL Exit 11-21-2017

		2025	2026	2027	2028	2029	2030
Wholesale Rural Revenue ($ Millions)	HMPL Exit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Budget	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Budget vs HMPL Exit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Wholesale Large Industrial Revenue ($ Millions)	HMPL Exit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Budget	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Budget vs HMPL Exit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

2017 -2031 Forecast:
Current Budget - Financial Metrics

	2018	2019	2020	2021	2022	2023	2024
Net Margins ($ Millions)	[redacted]						
Capital ($ Millions)	[redacted]						
TIER	[redacted]						
North Star	[redacted]						
Ending Cash Balance (In Millions $)	[redacted]						
CFC Equity Amount Over/(Under) Requirement (In Millions $)	[redacted]						
Equity (In Millions $)	[redacted]						
Debt (In Millions $)	[redacted]						
Debt Service Coverage Ratio	[redacted]						
Non-Member/Market $/MWh Capacity ($/MWh) Off-System $/MWh	[redacted]						
Non-Member/Market Revenue ($ millions)	[redacted]						
Capacity Price $/MW-Day (Calendar Year Achieved)	[redacted]						

Big Rivers Electric Corporation
Forecast Metrics - Budget versus HMPL Exit - 11-21-2017
Case No. 2018-00_____

2017 -2031 Forecast:
Current Budget - Financial Metrics

	2025	2026	2027	2028	2029	2030	2031
Net Margins ($ Millions)	[redacted]						
Capital ($ Millions)							
TIER							
North Star							
Ending Cash Balance (In Millions $)							
CFC Equity Amount Over/(Under) Requirement (In Millions $)							
Equity (In Millions $)							
Debt (In Millions $)							
Debt Service Coverage Ratio							
Non-Member/Market $/MWh Capacity ($/MWh) Off-System $/MWh							
Non-Member/Market Revenue ($ millions)							
Capacity Price $/MW-Day (Calendar Year Achieved)							

Sheet Name - Current Budget

Big Rivers Electric Corporation
Forecast Metrics - Budget versus HMPL Exit - 11-21-2017
Case No. 2018-00_____

2017 -2031 Forecast:
Current Budget - Financial Metrics

	2018	2019	2020	2021	2022	2023	2024
Capacity Sold (MW)	[redacted]						
Capacity Revenue ($ millions)							
Wholesale Rural Base Rate $/MWh							
Wholesale Rural Rate "All-In" (Net) $/MWh							
Wholesale Large Industrial Base Rate $/MWh							
Wholesale Large Industrial Rate "All-In" (Net) $/MWh							
Rural Revenue ($ millions)							
Large Industrial Revenue ($ millions)							
Non-Member Revenue ($ millions)							
Total							
Rural Base Rate Incr/(Decr)							
% over HMPL Exit							
Rural Whsl All In Rate Incr/(Decr)							
% over HMPL Exit							
LI Base Rate Incr/(Decr)							
% over HMPL Exit							
LI Whsl All In Rate Incr/(Decr)							
% over HMPL Exit							

Big Rivers Electric Corporation
Forecast Metrics - Budget versus HMPL Exit - 11-21-2017
Case No. 2018-00______

2017 -2031 Forecast:
Current Budget - Financial Metrics

	2025	2026	2027	2028	2029	2030	2031
Capacity Sold (MW)	[redacted]						
Capacity Revenue ($ millions)							
Wholesale Rural Base Rate $/MWh							
Wholesale Rural Rate "All-In" (Net) $/MWh							
Wholesale Large Industrial Base Rate $/MWh							
Wholesale Large Industrial Rate "All-In" (Net) $/MWh							
Rural Revenue ($ millions)							
Large Industrial Revenue ($ millions)							
Non-Member Revenue ($ millions)							
Total							
Rural Base Rate Incr/(Decr)							
% over HMPL Exit							
Rural Whsl All In Rate Incr/(Decr)							
% over HMPL Exit							
LI Base Rate Incr/(Decr)							
% over HMPL Exit							
LI Whsl All In Rate Incr/(Decr)							
% over HMPL Exit							

Sheet Name - Current Budget

Big Rivers Electric Corporation
Forecast Metrics - Budget v HMPL Exit 11-21-2017
Case No. 2018-00_____

2017-2030 Forecast:
Current Budget vs HMPL Exit

	2018			2019			2020		
	Current Budget	HMPL Exit	Diff	Current Budget	HMPL Exit	Diff	Current Budget	HMPL Exit	Diff
Net Margins ($ Millions)	[redacted]								
Capital ($ Millions)	[redacted]								
TIER	[redacted]								
North Star	[redacted]								
Ending Cash Balance (In Millions $)	[redacted]								
CFC Equity Amount Over/(Under) Requirement (In Millions $)	[redacted]								
Equity (In Millions $)	[redacted]								
Debt (In Millions $)	[redacted]								
Debt Service Coverage Ratio	[redacted]								
Non-Member/Market $/MWh Capacity ($/MWh) Off-System $/MWh	[redacted]								
Non-Member/Market Revenue ($ millions)	[redacted]								

Big Rivers Electric Corporation
Forecast Metrics - Budget v HMPL Exit 11-21-2017
Case No. 2018-00_____

2017-2030 Forecast:
Current Budget vs HMPL Exit

	2021			2022			2023		
	Current Budget	HMPL Exit	Diff	Current Budget	HMPL Exit	Diff	Current Budget	HMPL Exit	Diff
Net Margins ($ Millions)	[redacted]								
Capital ($ Millions)	[redacted]								
TIER	[redacted]								
North Star	[redacted]								
Ending Cash Balance (In Millions $)	[redacted]								
CFC Equity Amount Over/(Under) Requirement (In Millions $)	[redacted]								
Equity (In Millions $)	[redacted]								
Debt (In Millions $)	[redacted]								
Debt Service Coverage Ratio	[redacted]								
Non-Member/Market $/MWh Capacity ($/MWh) Off-System $/MWh	[redacted]								
Non-Member/Market Revenue ($ millions)	[redacted]								

Sheet Name - Budget vs HMPL Exit

Big Rivers Electric Corporation
Forecast Metrics - Budget v HMPL Exit 11-21-2017
Case No. 2018-00______

2017-2030 Forecast:
Current Budget vs HMPL Exit

	2024			2025			2026		
	Current Budget	HMPL Exit	Diff	Current Budget	HMPL Exit	Diff	Current Budget	HMPL Exit	Diff
Net Margins ($ Millions)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital ($ Millions)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
TIER	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
North Star	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ending Cash Balance (In Millions $)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CFC Equity Amount Over/(Under) Requirement (In Millions $)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Equity (In Millions $)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Debt (In Millions $)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Debt Service Coverage Ratio	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non-Member/Market $/MWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capacity ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Off-System $/MWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non-Member/Market Revenue ($ millions)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Sheet Name - Budget vs HMPL Exit

Big Rivers Electric Corporation
Forecast Metrics - Budget v HMPL Exit 11-21-2017
Case No. 2018-00_____

2017-2030 Forecast:
Current Budget vs HMPL Exit

	2027			2028			2029		
	Current Budget	HMPL Exit	Diff	Current Budget	HMPL Exit	Diff	Current Budget	HMPL Exit	Diff
Net Margins ($ Millions)	[redacted]								
Capital ($ Millions)	[redacted]								
TIER	[redacted]								
North Star	[redacted]								
Ending Cash Balance (In Millions $)	[redacted]								
CFC Equity Amount Over/(Under) Requirement (In Millions $)	[redacted]								
Equity (In Millions $)	[redacted]								
Debt (In Millions $)	[redacted]								
Debt Service Coverage Ratio	[redacted]								
Non-Member/Market $/MWh Capacity ($/MWh) Off-System $/MWh	[redacted]								
Non-Member/Market Revenue ($ millions)	[redacted]								

Big Rivers Electric Corporation
Forecast Metrics - Budget v HMPL Exit 11-21-2017
Case No. 2018-00_____

2017-2030 Forecast:
Current Budget vs HMPL Exit

	2030 Current Budget	2030 HMPL Exit	2030 Diff
Net Margins ($ Millions)	[redacted]	[redacted]	[redacted]
Capital ($ Millions)	[redacted]	[redacted]	[redacted]
TIER	[redacted]	[redacted]	[redacted]
North Star	[redacted]	[redacted]	[redacted]
Ending Cash Balance (In Millions $)	[redacted]	[redacted]	[redacted]
CFC Equity Amount Over/(Under) Requirement (In Millions $)	[redacted]	[redacted]	[redacted]
Equity (In Millions $)	[redacted]	[redacted]	[redacted]
Debt (In Millions $)	[redacted]	[redacted]	[redacted]
Debt Service Coverage Ratio	[redacted]	[redacted]	[redacted]
Non-Member/Market $/MWh	[redacted]	[redacted]	[redacted]
Capacity ($/MWh)	[redacted]	[redacted]	[redacted]
Off-System $/MWh	[redacted]	[redacted]	[redacted]
Non-Member/Market Revenue ($ millions)	[redacted]	[redacted]	[redacted]

Big Rivers Electric Corporation
Forecast Metrics - Budget v HMPL Exit 11-21-2017
Case No. 2018-00_____

2017-2030 Forecast:
Current Budget vs HMPL Exit

	2018			2019			2020		
	Current Budget	HMPL Exit	Diff	Current Budget	HMPL Exit	Diff	Current Budget	HMPL Exit	Diff
Capacity Price $/MW-Day (Calendar Year Achieved)	[redacted]								
Capacity Sold (MW)									
Capacity Revenue ($ millions)									
Wholesale Rural Base Rate $/MWh									
Wholesale Rural Rate "All-In" (Net) $/MWh									
Wholesale Large Industrial Base Rate $/MWh									
Wholesale Large Industrial Rate "All-In" (Net) $/MWh									
Rural Revenue ($ millions)									
Large Industrial Revenue ($ millions)									
Non-Member Revenue ($ millions)									
Total									

Sheet Name - Budget vs HMPL Exit

Big Rivers Electric Corporation
Forecast Metrics - Budget v HMPL Exit 11-21-2017
Case No. 2018-00_____

2017-2030 Forecast:
Current Budget vs HMPL Exit

	2021			2022			2023		
	Current Budget	HMPL Exit	Diff	Current Budget	HMPL Exit	Diff	Current Budget	HMPL Exit	Diff
Capacity Price $/MW-Day (Calendar Year Achieved)	[redacted]								
Capacity Sold (MW)									
Capacity Revenue ($ millions)									
Wholesale Rural Base Rate $/MWh									
Wholesale Rural Rate "All-In" (Net) $/MWh									
Wholesale Large Industrial Base Rate $/MWh									
Wholesale Large Industrial Rate "All-In" (Net) $/MWh									
Rural Revenue ($ millions)									
Large Industrial Revenue ($ millions)									
Non-Member Revenue ($ millions)									
Total									

Sheet Name - Budget vs HMPL Exit

Big Rivers Electric Corporation
Forecast Metrics - Budget v HMPL Exit 11-21-2017
Case No. 2018-00_____

2017-2030 Forecast:
Current Budget vs HMPL Exit

	2024			2025			2026		
	Current Budget	HMPL Exit	Diff	Current Budget	HMPL Exit	Diff	Current Budget	HMPL Exit	Diff
Capacity Price $/MW-Day (Calendar Year Achieved)	[redacted]								
Capacity Sold (MW)									
Capacity Revenue ($ millions)									
Wholesale Rural Base Rate $/MWh									
Wholesale Rural Rate "All-In" (Net) $/MWh									
Wholesale Large Industrial Base Rate $/MWh									
Wholesale Large Industrial Rate "All-In" (Net) $/MWh									
Rural Revenue ($ millions)									
Large Industrial Revenue ($ millions)									
Non-Member Revenue ($ millions)									
Total									

Sheet Name - Budget vs HMPL Exit

Big Rivers Electric Corporation
Forecast Metrics - Budget v HMPL Exit 11-21-2017
Case No. 2018-00_____

2017-2030 Forecast:
Current Budget vs HMPL Exit

	2027			2028			2029		
	Current Budget	HMPL Exit	Diff	Current Budget	HMPL Exit	Diff	Current Budget	HMPL Exit	Diff
Capacity Price $/MW-Day (Calendar Year Achieved)	[redacted]								
Capacity Sold (MW)									
Capacity Revenue ($ millions)									
Wholesale Rural Base Rate $/MWh									
Wholesale Rural Rate "All-In" (Net) $/MWh									
Wholesale Large Industrial Base Rate $/MWh									
Wholesale Large Industrial Rate "All-In" (Net) $/MWh									
Rural Revenue ($ millions)									
Large Industrial Revenue ($ millions)									
Non-Member Revenue ($ millions)									
Total									

Sheet Name - Budget vs HMPL Exit

Big Rivers Electric Corporation
Forecast Metrics - Budget v HMPL Exit 11-21-2017
Case No. 2018-00_____

2017-2030 Forecast:
Current Budget vs HMPL Exit

	2030		
	Current Budget	HMPL Exit	Diff
Capacity Price $/MW-Day (Calendar Year Achieved)	[redacted]		
Capacity Sold (MW)			
Capacity Revenue ($ millions)			
Wholesale Rural Base Rate $/MWh			
Wholesale Rural Rate "All-In" (Net) $/MWh			
Wholesale Large Industrial Base Rate $/MWh			
Wholesale Large Industrial Rate "All-In" (Net) $/MWh			
Rural Revenue ($ millions)			
Large Industrial Revenue ($ millions)			
Non-Member Revenue ($ millions)			
Total			

Big Rivers Electric Corporation
Forecast Metrics - Budget versus HMPL Exit - 11-21-2017
Case No. 2018-00_____

2017-2031 Forecast

HMPL Exit - Financial Metrics

	2018	2019	2020	2021	2022	2023	2024
Net Margins ($ Millions)	[redacted]						
Capital ($ Millions)							
TIER							
North Star							
Ending Cash Balance (In Millions $)							
CFC Equity Amount Over/(Under) Requirement (In Millions $)							
Equity (In Millions $)							
Debt (In Millions $)							
Debt Service Coverage Ratio							
Non-Member/Market $/MWh Capacity ($/MWh) Off-System $/MWh							
Non-Member/Market Revenue ($ millions)							
Capacity Price $/MW-Day (Calendar Year Achieved)							

Sheet Name - HMPL Exit

Big Rivers Electric Corporation
Forecast Metrics - Budget versus HMPL Exit - 11-21-2017
Case No. 2018-00_____

2017-2031 Forecast

HMPL Exit - Financial Metrics

	2025	2026	2027	2028	2029	2030	2031
Net Margins ($ Millions)	[redacted]						
Capital ($ Millions)							
TIER							
North Star							
Ending Cash Balance (In Millions $)							
CFC Equity Amount Over/(Under) Requirement (In Millions $)							
Equity (In Millions $)							
Debt (In Millions $)							
Debt Service Coverage Ratio							
Non-Member/Market $/MWh							
Capacity ($/MWh)							
Off-System $/MWh							
Non-Member/Market Revenue ($ millions)							
Capacity Price $/MW-Day (Calendar Year Achieved)							

Big Rivers Electric Corporation
Forecast Metrics - Budget versus HMPL Exit - 11-21-2017
Case No. 2018-00______

2017-2031 Forecast
HMPL Exit - Financial Metrics

	2018	2019	2020	2021	2022	2023	2024
Capacity Sold (MW)	[redacted]						
Capacity Revenue ($ millions)							
Wholesale Rural Base Rate $/MWh							
Wholesale Rural Rate "All-In" (Net) $/MWh							
Wholesale Large Industrial Base Rate $/MWh							
Wholesale Large Industrial Rate "All-In" (Net) $/MWh							
Rural Revenue ($ millions)							
Large Industrial Revenue ($ millions)							
Non-Member Revenue ($ millions)							
Total							
Rural Base Rate Incr/(Decr)							
% over prior budget							
Rural Whsl All In Rate Incr/(Decr)							
% over prior budget							
LI Base Rate Incr/(Decr)							
% over prior budget							
LI Whsl All In Rate Incr/(Decr)							
% over prior budget							

Sheet Name - HMPL Exit

Big Rivers Electric Corporation
Forecast Metrics - Budget versus HMPL Exit - 11-21-2017
Case No. 2018-00_____

2017-2031 Forecast

HMPL Exit - Financial Metrics

	2025	2026	2027	2028	2029	2030	2031
Capacity Sold (MW)	[redacted]						
Capacity Revenue ($ millions)							
Wholesale Rural Base Rate $/MWh							
Wholesale Rural Rate "All-In" (Net) $/MWh							
Wholesale Large Industrial Base Rate $/MWh							
Wholesale Large Industrial Rate "All-In" (Net) $/MWh							
Rural Revenue ($ millions)							
Large Industrial Revenue ($ millions)							
Non-Member Revenue ($ millions)							
Total							
Rural Base Rate Incr/(Decr)							
% over prior budget							
Rural Whsl All In Rate Incr/(Decr)							
% over prior budget							
LI Base Rate Incr/(Decr)							
% over prior budget							
LI Whsl All In Rate Incr/(Decr)							
% over prior budget							

Big Rivers Electric Corporation
G and A Gross vs Net Budget
Case No. 2018-00______

Resp Org	Department Name	*Gross* 2018 Budget	Net 2018 Budget
001	President and CEO	[redacted]	[redacted]
010	Vice President Administrative Services	[redacted]	[redacted]
011	Chief Financial Officer	[redacted]	[redacted]
012	Vice President Production	[redacted]	[redacted]
014	Vice President System Operations	[redacted]	[redacted]
015	Director Communications & Community Relations	[redacted]	[redacted]
016	Vice President Environmental Services and Construction	[redacted]	[redacted]
020	Fuels & Power Accounting	[redacted]	[redacted]
022	Director Fuels Procurement	[redacted]	[redacted]
025	Vice President Energy Services	[redacted]	[redacted]
060	Safety Production	[redacted]	[redacted]
110	Corporate Files	[redacted]	[redacted]
150	Safety and Training	[redacted]	[redacted]
151	Security-Sebree	[redacted]	[redacted]
152	Security-Coleman	[redacted]	[redacted]
153	Security-Wilson	[redacted]	[redacted]
170	General Services	[redacted]	[redacted]
190	Manager Marketing & Member Relations	[redacted]	[redacted]
200	Manager Budgets	[redacted]	[redacted]
205	Manager General Accounting	[redacted]	[redacted]
210	Manager Finance	[redacted]	[redacted]
215	Director Rates & Tariffs	[redacted]	[redacted]
218	Director Accounting/Finance	[redacted]	[redacted]
219	Director Risk Management & Strategic Planning	[redacted]	[redacted]
220	Manager Employment & Benefits	[redacted]	[redacted]
251	Director Supply Chain	[redacted]	[redacted]
300	Director Information Systems & Technology	[redacted]	[redacted]
302	Manager Application Development	[redacted]	[redacted]
310	Manager Environmental	[redacted]	[redacted]
311	Enterprise Risk Management	[redacted]	[redacted]
312	Governmental Relations	[redacted]	[redacted]
355	Real Estate	[redacted]	[redacted]
370	Manager Engineering & Energy Control	[redacted]	[redacted]
405	Energy Control excl MISO	[redacted]	[redacted]
TOTAL		[redacted]	[redacted]

Gross includes the City's Share of HMP&L SII expenses

Big Rivers Electric Corporation
Labor Impact of HMPL Split
Case No. 2018-00_____

	2016	2017	2018	2019
Gross Labor	20,552,403	21,024,890	21,634,999	22,193,119
Net Labor	19,702,311	20,118,622	20,686,585	21,220,845
	850,092	906,268	948,414	972,274

*Labor includes capitalized labor and doesn't include reduction for churn

HMPL G&A Agreement (Base Case)	625,639
Impact to Big Rivers Margins Fav/(UnFav)	(322,775)

Big Rivers Electric Corporation
Station Two Estimated Net Book Value
Case No. 2018-00_____

Station II Assets
Net Book Value
As of 12/31/2018 [1]

Category [2]	Description	Plant In-Service Account	Gross Book Value	Accumulated Depreciation [3]	Net Book Value
HMPL	STRUCTURES-HMPL	10103115	548,133.00	(67,892.58)	480,240.42
HMPL SHARE	STRUCTURES-R/HMPL	10103116	590,653.72	(79,125.72)	511,528.00
HMPL SHARE	STRUCTURES-R/G/HMPL	10103117	300,812.76	(100,126.63)	200,686.13
HMPL	BOILER PLANT EQUIPMNT	10103125	25,252,845.00	659,958.58	25,912,803.58
HMPL	ENVIRONMTL COMPLIANCE	1010312F	32,014,564.00	(7,381,996.85)	24,632,567.15
HMPL SHARE	ENVIRON COMPL-R/HMPL	1010312G	1,520,081.28	(305,696.40)	1,214,384.88
HMPL SHARE	BOILERPLANT,EC,HMPL/GREEN	1010312J	4,503.26	(2,086.63)	2,416.63
HMPL	SCRUBBER	1010312K	37,811,155.00	(19,204,101.69)	18,607,053.31
HMPL	ENVIRONMTL COMPL-SHORT LIFE	1010312Q	6,145,688.00	(6,171,648.44)	(25,960.44)
HMPL SHARE	BOILER PLANT-SHORT LIFE-R/HMPL	1010312U	148,912.75	(36,024.89)	112,887.86
HMPL	BOILER PLANT-SHORT LIFE	1010312Z	980,100.00	(99,279.13)	880,820.87
HMPL SHARE	BOILER PLANT-R/HMPL	10103126	2,506,547.39	(78,720.07)	2,427,827.32
HMPL SHARE	BOILER PLANT-R/G/HMPL	10103127	137,687.34	(31,801.84)	105,885.50
HMPL	TURBOGENERATOR UNITS	10103145	8,991,467.00	(1,241,623.37)	7,749,843.63
HMPL SHARE	TURBINE PLT-R/HMPL	10103146	890,470.28	12,237.53	902,707.81
HMPL SHARE	TURBINE PLT-R/G/HMPL	10103147	8,303.56	(3,533.38)	4,770.18
HMPL	ACCESS ELECTRIC EQUIP	10103155	4,462,079.00	1,444,706.16	5,906,785.16
HMPL SHARE	ACCESS ELECTRIC EQUIPMENT	10103157	15,228.84	(2,073.17)	13,155.67
HMPL	MISC POWER PLANT EQUIP	10103165	454,968.00	(100,094.63)	354,873.37
HMPL SHARE	COMMON PLANT-R/HMPL	10103166	803,896.15	(110,087.99)	693,808.16
HMPL SHARE	COMMON PLANT-R/G/HMPL	10103167	52,151.92	(14,527.06)	37,624.86
HMPL SHARE	OFFICE FURN & EQUIP-R/HMPL	10103916	5,757.21	(4,753.43)	1,003.78
HMPL SHARE	OFFICE FURN & EQUIP-R/G/HMPL	10103917	7,580.64	(6,326.27)	1,254.37
HMPL SHARE	MISC EQUIP-R/HMPL	10103986	-	-	-
HMPL SHARE	MISC EQUIP-R/G/HMPL	10103987	430.46	(290.96)	139.50
TOTAL			**123,654,016.56**	**(32,924,908.86)**	**90,729,107.70**

[1] Account Balances as of 12/31/2018 are estimated figures from the 2016-2019 Depreciation Budget.

[2] HMPL SHARE categories include accounts in which assets are shared between the Sebree Station plants. The Station II split allocation can be found on the 'Splits' worksheet.

[3] Accumulated Depreciation includes the Accumulated Depreciation on active assets ('Account Balances' Column D) and Gain/Loss amounts on retired assets in the Depreciation Reserve accounts ('Account Balances' Column E).

Big Rivers Electric Corporation
Statin Two Estimated Net Book Value
Case No. 2018-00_____

Estimated Account Balances

2016-2019 Depreciation Budget

As of 12.31.2018

Plant In Service

Account	Gross Book Value	Accum Depr	Depr Reserve
10103010	420.00	-	-
10103020	66,476.00	-	-
10103101	83,342.00	-	-
10103102	1,124,665.00	-	-
10103103	1,110,712.00	-	-
10103104	2,218,858.00	-	-
10103111	3,272,657.00	(3,403,735.46)	130,210.09
10103112	19,771,615.00	(18,552,474.21)	387,149.33
10103113	27,404,354.00	(22,821,117.09)	716,110.65
10103114	75,499,371.00	(48,315,075.70)	1,526,081.13
10103115	548,133.00	(127,978.51)	60,085.93
10103116	795,922.00	(177,366.02)	70,741.95
10103117	1,135,571.00	(429,164.14)	51,185.16
10103119	853,947.00	(518,240.46)	48,656.82
10103120	166,704.00	(24,242.92)	10,082.98
10103121	7,703,496.00	(7,196,552.73)	1,077,977.86
10103122	82,506,522.00	(50,030,594.94)	7,614,553.64
10103123	183,700,886.00	(133,782,481.76)	12,005,511.98
10103124	416,940,738.00	(274,893,883.04)	27,213,265.08
10103125	25,252,845.00	(5,331,620.13)	5,991,578.71
10103126	3,377,641.00	(731,407.36)	625,329.92
10103127	519,771.00	(164,914.24)	44,862.00
1010312A	1,114,989.00	(141,821.16)	246,284.39
1010312B	5,069,516.00	(2,838,605.26)	114,664.33
1010312C	122,674,114.00	(34,545,314.00)	4,062,030.05
1010312D	131,458,394.00	(81,400,832.51)	17,011,513.12
1010312E	265,640,648.00	(172,150,696.78)	23,936,929.42
1010312F	32,014,564.00	(10,277,701.84)	2,895,704.99
1010312G	2,048,351.00	(478,453.14)	66,518.91
1010312J	15,438.00	(7,153.34)	-
1010312K	37,811,155.00	(20,054,292.91)	850,191.22
1010312N	1,104,354.00	(1,135,853.66)	161,178.00
1010312P	7,500,875.00	(8,238,057.48)	2,978,537.18
1010312Q	6,145,688.00	(6,734,747.45)	563,099.01
1010312U	200,664.00	(140,675.53)	92,131.00
1010312V	23,762.00	(37,182.16)	22,670.75
1010312W	412,629.00	(585,740.70)	169,176.46
1010312X	1,665,592.00	(1,349,545.79)	807,738.36

Big Rivers Electric Corporation
Statin Two Estimated Net Book Value
Case No. 2018-00_____

Estimated Account Balances

2016-2019 Depreciation Budget

As of 12.31.2018

Plant In Service

Account	Gross Book Value	Accum Depr	Depr Reserve
1010312Y	899,003.00	(765,673.22)	290,018.00
1010312Z	980,100.00	(797,208.32)	697,929.19
10103141	4,066,364.00	(4,337,735.24)	385,928.55
10103142	33,795,866.00	(24,326,942.07)	2,320,329.61
10103143	62,983,645.00	(47,972,378.37)	3,866,126.07
10103144	129,376,894.00	(86,523,565.92)	3,263,707.24
10103145	8,991,467.00	(2,594,617.42)	1,352,994.05
10103146	1,199,933.00	(141,893.49)	158,383.90
10103147	31,346.00	(13,424.59)	86.02
10103151	1,701,148.00	(1,261,954.61)	160,029.73
10103152	9,440,861.00	(6,907,613.42)	216,566.60
10103153	18,512,350.00	(14,401,650.67)	823,436.35
10103154	35,817,460.00	(23,775,874.29)	641,270.05
10103155	4,462,079.00	(329,945.70)	1,774,651.86
10103156	37,556.00	(2,255.28)	22,561.00
10103157	57,489.00	(7,826.25)	-
10103159	43,548.00	(36,421.00)	17,753.16
10103160	143,212.00	(40,350.77)	-
10103161	15,854.00	(2,746.97)	-
10103162	1,344,809.00	(408,811.70)	15,861.64
10103163	1,578,730.00	(432,263.66)	119,996.60
10103164	1,583,280.00	(428,181.64)	353,256.52
10103165	454,968.00	(132,014.63)	31,920.00
10103166	1,083,272.00	(228,650.07)	80,303.50
10103167	196,874.00	(54,839.79)	-
10103169	750,845.00	(143,360.78)	230,156.00
10103410	193,561.00	(137,005.85)	18,900.79
10103420	1,446,805.00	(1,522,537.45)	65,744.49
10103430	6,351,497.00	(4,782,753.28)	173,752.94
10103440	1,188,518.00	(1,049,785.57)	31,393.64
10103450	633,795.00	(269,132.25)	112,040.77
10103500	14,548,691.00	-	-
10103501	704,868.00	-	-
10103520	6,385,859.00	(4,259,786.18)	151,234.91
10103521	54,739.00	(23,914.82)	2,038.61
10103522	157,305.00	(156,093.65)	(1,378.31)
10103524	698,103.00	(465,564.45)	5,409.34
10103530	111,482,221.00	(53,690,581.38)	11,941,682.64

Big Rivers Electric Corporation
Statin Two Estimated Net Book Value
Case No. 2018-00_____

Estimated Account Balances
2016-2019 Depreciation Budget
As of 12.31.2018

Plant In Service

Account	Gross Book Value	Accum Depr	Depr Reserve
10103531	3,194,085.00	(2,559,457.50)	299,446.40
10103532	5,627,588.00	(5,255,220.43)	283,146.03
10103533	5,997,630.00	(5,722,587.18)	2.38
10103534	22,082,380.00	(16,855,735.68)	239,935.40
10103540	8,134,239.00	(5,793,106.74)	(35,730.51)
10103541	146,747.00	(132,776.06)	-
10103550	48,989,285.00	(30,313,595.40)	-
10103551	234,314.00	(240,620.56)	7.90
10103560	57,941,545.00	(30,771,203.17)	-
10103561	86,901.00	(88,896.59)	24.83
10103890	407,251.00	-	-
10103900	5,816,126.00	(3,723,395.08)	751,069.54
10103910	1,130,303.00	(1,005,542.61)	630,911.53
10103912	29,118,776.00	(18,568,394.13)	1,572,279.05
10103916	7,758.00	(6,405.38)	-
10103917	28,617.00	(23,881.74)	-
10103922	3,066,084.00	(1,704,566.69)	(260,556.12)
10103923	1,686,867.00	(1,616,193.05)	210,681.41
10103930	111,491.00	(109,330.89)	2,580.03
10103940	957,430.00	(761,652.92)	17,910.88
10103950	311,920.00	(259,277.13)	(10,559.85)
10103960	1,029,102.00	(292,443.76)	(25,104.49)
10103961	788,773.00	(234,598.87)	(77,004.68)
10103970	10,620,545.00	(4,192,082.66)	(37,090.12)
10103980	378,511.00	(268,115.28)	59,872.18
10103987	1,625.00	(1,098.38)	-
10113525	185,107.00	(36,672.24)	-
10113535	6,511,341.00	(1,553,489.30)	-
10113545	312,558.00	(55,444.03)	-
10113555	79,207.00	(20,424.58)	-
10113565	104,571.00	(22,181.93)	-
10503401	475,968.00	-	-
10103913	-	-	(74,758.64)
TOTAL	**2,147,914,939.00**	**(1,321,231,267.13)**	**144,422,899.03**

Big Rivers Electric Corporation
Station Two Estimated Net Book Value
Case No. 2018-00_____

Station II Allocation Splits[1]

1 Reid/Station Two split @ 12/31/17:

Plant	MW	%
Reid	65	0.2579
Station II	187	0.7421
Total	**252**	**1.0000**

2 Reid/Station Two/Green split @ 12/31/17:

Plant	MW	%
Reid	65	0.0921
Station II	187	0.2649
Green	454	0.6431
Total	**706**	**1.0001**

3 Green/Station Two split @ 12/31/17:

Plant	MW	%
Green	454	0.7083
Station II	187	0.2917
Total	**641**	**1.0000**

[1] Station II megawatt split is based on HMPL Capacity Letter dated March 24, 2015, utilizing the "Allocated to BREC" amount for June 1, 2018-May 31, 2019.

Exhibit Berry-3

GDS Associates, Inc.

Integrated Resource Plan Report **– April 19, 2018**

Prepared for: **Henderson Municipal Power & Light**

GDS ASSOCIATES, INC.

engineers and consultants

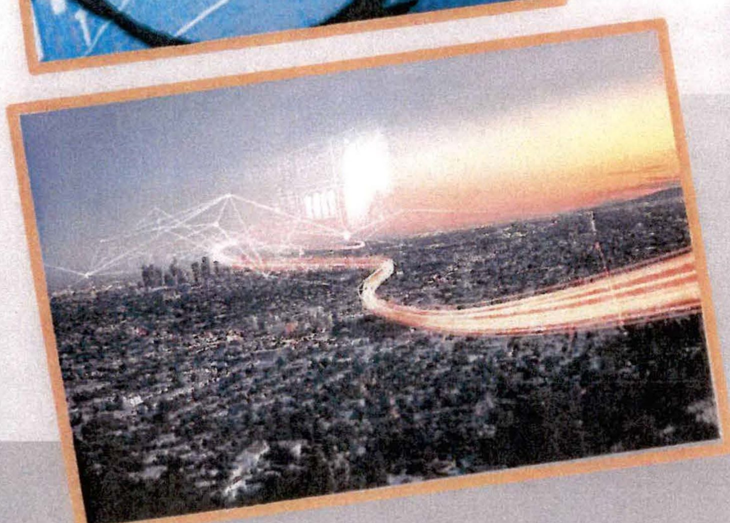
Integrated Resource Plan Report

Prepared for:

HENDERSON MUNICIPAL POWER & LIGHT

HMP&L

HENDERSON MUNICIPAL POWER & LIGHT



Prepared by:

GDS Associates, Inc.

1850 Parkway Place, Suite 800

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www.gdsassociates.com

April 19, 2018

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1.0 Introduction

GDS Associates, Inc. ("GDS") is a multi-service consulting and engineering firm with extensive engineering, project management, and consulting experience. The firm was formed in 1986 and employs a staff of approximately 175 professionals and support personnel. GDS' broad range of expertise focuses on clients associated with, or affected by, electric, gas, water and wastewater utilities. Henderson Municipal Power & Light (HMP&L) retained GDS to perform an Integrated Resource Plan (IRP) and evaluate potential supply-side resource alternatives and compare those alternatives to HMP&L's power supply options involving the Henderson Generating Station #2 (HGS), including a scenario where HMP&L continues its present arrangements with Big Rivers Electric Corporation (BREC).

The IRP involves an assessment of a number of power supply resource alternatives, including gas, modular nuclear, and renewable resources, as well as energy block purchases from a third-party supplier. The cost of owning and operating the various resource portfolios is evaluated over a 20 year study period (2019 through 2038) and a comparison, on a net present value basis, was used to evaluate the most cost-effective resource portfolio to meet HMP&L's total capacity and energy requirements. The core issue that the IRP process was designed to address was whether HMP&L should continue to invest and maintain the HGS facility or if they should consider retiring HGS and moving forward with another power supply arrangement.

In addition to evaluating supply-side alternatives, the IRP also reviews potential cost-effective DSM and energy efficiency programs that have been utilized by other Kentucky electric utilities. While the IRP does not take into account the potential benefits of implementing these DSM / energy efficiency programs, it does provide a summary of the most beneficial programs that HMP&L should consider first if it does decide to provide those programs to its retail customers.

As an overview, the IRP report provides an in-depth review of the load forecast process for projecting HMP&L's total energy and capacity requirements, details on the cost assumptions for HGS and the alternative resources, outlines key assumptions for the evaluation, and describes the modeling process to determine the variable cost of each resource portfolio. All of this information is used in Section 7 to develop the long-range financial forecast which evaluates the financial impacts of the various generation resource alternatives (e.g., impacts on cash flows, financial metrics, and retail rates). Finally, the report summarizes the cost of each portfolio alternative and shows the potential volatility of each scenario due to different sensitivities (i.e. coal and natural gas fuel prices). In Section 10 of the IRP report, GDS recommends, among other things, that HMP&L should retire the HGS facility and begin the process of identifying other short-term and long-term power supply alternatives to meet its future power supply requirements.

2.0 HMP&L Capacity and Energy Requirements

The IRP study assumes that HMP&L will maintain the appropriate amount of capacity resources to meet its load requirements in MISO throughout the 20 year study period. MISO's load requirements are based upon electric utilities' annual load forecast of summer peak demands and adjusted for a coincident peak on the MISO system. The utility's peak demand is increased for transmission losses and the MISO published planning reserve margin, currently 8.2%. MISO's planning reserve margin is calculated every year in accordance with MISO's tariff and is designed to account for the unexpected loss of generation resources (forced outages or derations), transmission contingencies, as well as changes in loads due to hotter than normal weather (for summer capacity planning purposes).

The utility's adjusted projected peak demand serves as the basis for the utility's capacity resource requirements, at least on an annual basis in MISO, and the utility has an ability to procure the necessary capacity resources from MISO's annual capacity auction or under a bilateral agreement from an independent third-party provider. For purposes of the IRP evaluation, the study assumes that HMP&L will purchase capacity from MISO in all scenarios where its capacity requirements exceed its capacity resources. And vice versa, sell excess capacity to MISO when excess capacity is available.

2.1 HGS OWNERSHIP AND SEPA CAPACITY

HMP&L owns HGS which has a net rated capability of 312 MW. Today, HMP&L takes a reservation of HGS capacity to meet its capacity requirements and the reservation takes into account HMP&L's SEPA contract and the 12 MW of capacity and associated energy that are delivered from the SEPA transmission system to MISO. For all scenarios involving continued operation and ownership of HGS, HMP&L either is projected to have exactly the amount of capacity for its MISO capacity requirements or it has excess capacity to sell to the MISO market. The IRP evaluation process captures the financial benefits of selling capacity to the MISO market over the study period.

2.2 DETERMINING CAPACITY REQUIREMENTS

For all resource scenarios, including the HGS related scenarios, HMP&L's capacity requirements were computed using the base load forecast for HMP&L's summer peak demand, adjusted by a MISO coincident peak factor of 96%, and increased by MISO's transmission loss factor and MISO's 8.2% planning reserve margin. The incremental capacity requirement was calculated by subtracting the SEPA capacity credit from the calculated capacity requirement. For all non-coal resource scenarios, the net capacity requirement was further reduced by any new, incremental capacity resources that are procured by HMP&L and the net amount of capacity deficiency (all non-coal scenarios had a capacity deficiency) was purchased from the MISO market at the annual prevailing capacity price (determined according to the capacity pricing in the Base and High capacity pricing sensitivities further described in Section 5.0).

The base load forecast reveals that HMP&L's projected load growth will be flat to slightly declining over the study period. While the IRP study only utilizes the base load forecast for all evaluations and analyses, one key assumption was that any load growth over the study period could be initially addressed with viable DSM programs that are further described in Section 4.0. Since HMP&L does not have any DSM programs in place today, there could be significant benefits if the need arises to reduce peak demands.

2.3 ANNUAL ENERGY FOR LOAD FORECASTS

2.3.1 Base Case

Energy requirements are projected to increase at an average compound rate of 0.1% per year from 2017 through 2027. Low energy growth is attributed to the expectation of minimal to no customer growth, declining trends in average household consumption due to continued increases in appliance efficiencies and energy conservation, and the expectation of no new customer growth in the industrial sector.

Annual peak demand is projected to decline or remain nearly flat throughout the forecast horizon, declining by less than 1 MW to a level of 106 MW by 2027. Annual peaks are projected to continue occurring during the summer season. Summer demands have trended down the last ten years, and the trend is expected to continue for the above stated reasons. Load factor is projected to increase over the forecast horizon, as growth in energy requirements is expected to exceed growth in peak demand. Winter peak demands, conversely, are projected to rise at a pace higher than energy requirements growth, increasing to a level of 97 MW by 2027. Growth in winter demand is due primarily to continued increases in the market shares of electric heating and electric water heating.

Energy and demand requirements are summarized in Table 2-1. Refer to the 2017 Load Forecast report for a more detailed presentation of the annual and monthly values.

Table 2-1: HMP&L Summarized Energy and Demand Requirements

Year	Energy Requirements (MWh)	Compound Growth Rate	Summer Peak Demand (MW)	Compound Growth Rate	Summer Load Factor	Winter Peak Demand (MW)	Compound Growth Rate	Winter Load Factor
2007	690,270		125.0		63.0%	101.0		78.0%
2012	622,254	-2.1%	115.0	-1.7%	61.8%	89.0	-2.5%	79.8%
2017	626,016	0.1%	107.3	-1.4%	66.6%	93.0	0.9%	76.8%
2022	627,384	0.0%	106.7	-0.1%	67.1%	95.7	0.6%	74.8%
2027	630,441	0.1%	106.4	-0.1%	67.6%	96.8	0.2%	74.4%

Values for 2007 and 2012 are actual amounts. Values for 2017-2027 represent amounts based on normal weather.

The base case forecast reflects the following key assumptions. Refer to the 2017 Load Forecast report for more details.

- Insignificant residential and commercial customer growth over the next ten years;
- Nominal retail price of electricity will grow at the rate of inflation;
- Average electric heating and air conditioning efficiencies will track the projections made by the Energy Information Administration ("EIA") in their Annual Energy Outlook;
- Current saturation levels of air conditioning and electric space heating (primary heating source) for the residential class are estimated at 90% and 52%, respectively. Levels for both are projected to remain nearly constant over the forecast horizon;
- No new industrial customer growth.

2.3.2 Forecast Scenarios

It is important to recognize that no forecast will prove to be perfectly accurate. It can only be as accurate as the numerous assumptions and data sources upon which projections are based. The model developed for the base case forecast demonstrates that energy consumption is explained to a large degree by those factors specified in the models. However, it should be recognized that changes in these factors over time will deviate from the projections shown herein, and actual energy consumption will deviate to some degree from the forecast. As a result, it is necessary to update the forecast periodically to capture recent trends in energy consumption and calibrate the impacts of the driver variables. Any such update must recognize that the economy is ever changing and will be subject from time to time to unique events that could significantly impact economic activity. It is important that any forecast considers a sensible range of future values to address uncertainty.

Six forecast scenarios were considered during the development of the IRP. The first two reflect optimistic and pessimistic economic outlooks relative to the base case forecast. The next two scenarios reflect extreme and mild weather relative to the base case forecast, which reflects average weather for the 20 years ending 2016. The final two scenarios reflect the aggregate impacts of the economic and weather sensitivities.

Table 2-2: HMP&L Forecast Energy Requirements

Energy Requirements (MWh)							
Year	BASE CASE	Optimistic Economy	Pessimistic Economy	Extreme Weather	Mild Weather	Optimistic Economy & Extreme Weather	Pessimistic Economy & Mild Weather
2018	626,383	632,647	620,119	670,230	601,328	676,494	595,064
2019	626,864	638,973	613,918	670,744	601,789	682,854	588,844
2020	626,765	645,363	607,779	670,639	601,695	689,237	582,708
2021	627,012	651,817	601,701	670,903	601,932	695,708	576,621
2022	627,384	658,335	595,684	671,301	602,289	702,252	570,589
2023	627,835	664,918	589,727	671,784	602,722	708,867	564,614
2024	628,348	671,568	583,830	672,333	603,214	715,552	558,696
2025	628,950	678,283	577,992	672,976	603,792	722,310	552,834
2026	629,666	685,066	572,212	673,743	604,480	729,143	547,025
2027	630,441	691,917	566,490	674,571	605,223	736,048	541,272

Table 2-3: HMP&L Forecast Demand Requirements

	Demand Requirements (MW)						
Year	*BASE CASE*	*Optimistic Economy*	*Pessimistic Economy*	*Extreme Weather*	*Mild Weather*	*Optimistic Economy & Extreme Weather*	*Pessimistic Economy & Mild Weather*
2018	*107.3*	*108.4*	*106.3*	*114.9*	*102.0*	*115.9*	*100.9*
2019	*107.2*	*109.5*	*105.2*	*114.7*	*101.8*	*117.0*	*99.9*
2020	*107.0*	*110.6*	*104.2*	*114.5*	*101.6*	*118.1*	*98.8*
2021	*106.8*	*111.7*	*103.2*	*114.3*	*101.5*	*119.2*	*97.8*
2022	*106.7*	*112.9*	*102.1*	*114.2*	*101.4*	*120.3*	*96.8*
2023	*106.6*	*114.0*	*101.1*	*114.1*	*101.3*	*121.5*	*95.8*
2024	*106.5*	*115.2*	*100.1*	*114.0*	*101.2*	*122.6*	*94.8*
2025	*106.5*	*116.3*	*99.1*	*113.9*	*101.1*	*123.8*	*93.8*
2026	*106.4*	*117.5*	*98.1*	*113.9*	*101.1*	*124.9*	*92.8*
2027	*106.4*	*118.7*	*97.1*	*113.8*	*101.1*	*126.1*	*91.8*

Load Forecast Scenarios

Figure 2-1: HMP&L Energy Forecast Scenario

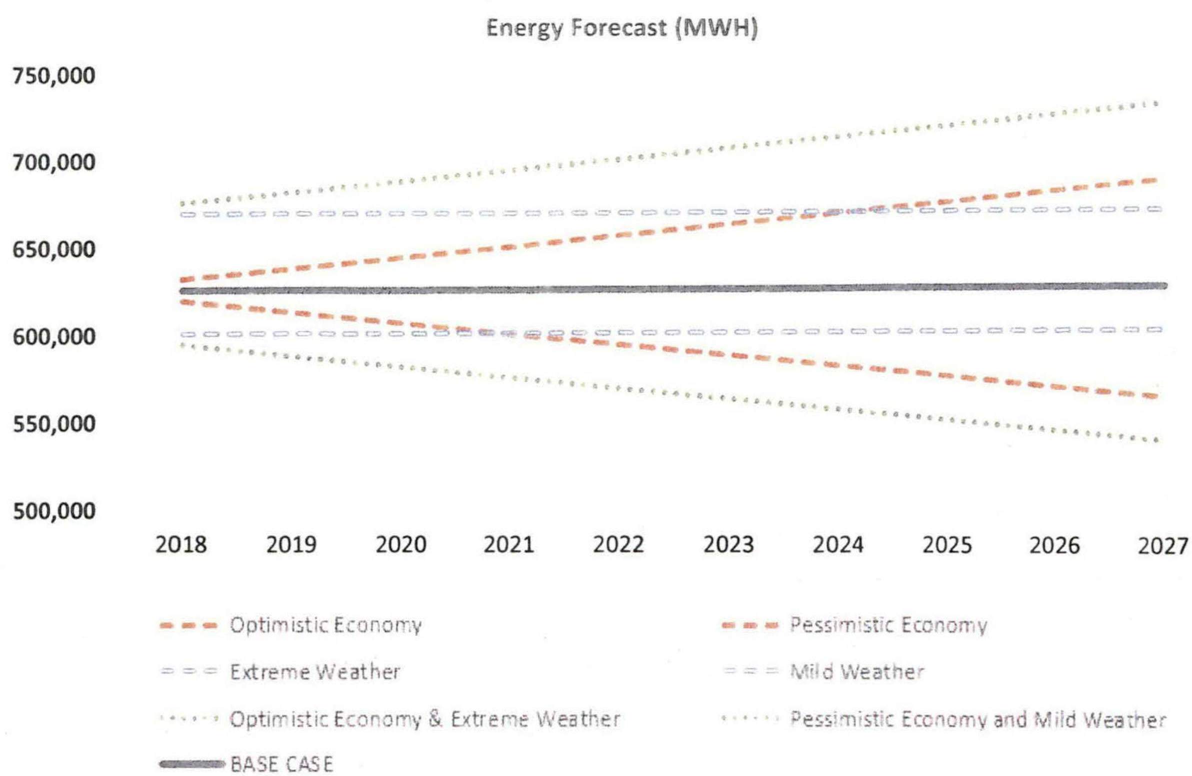
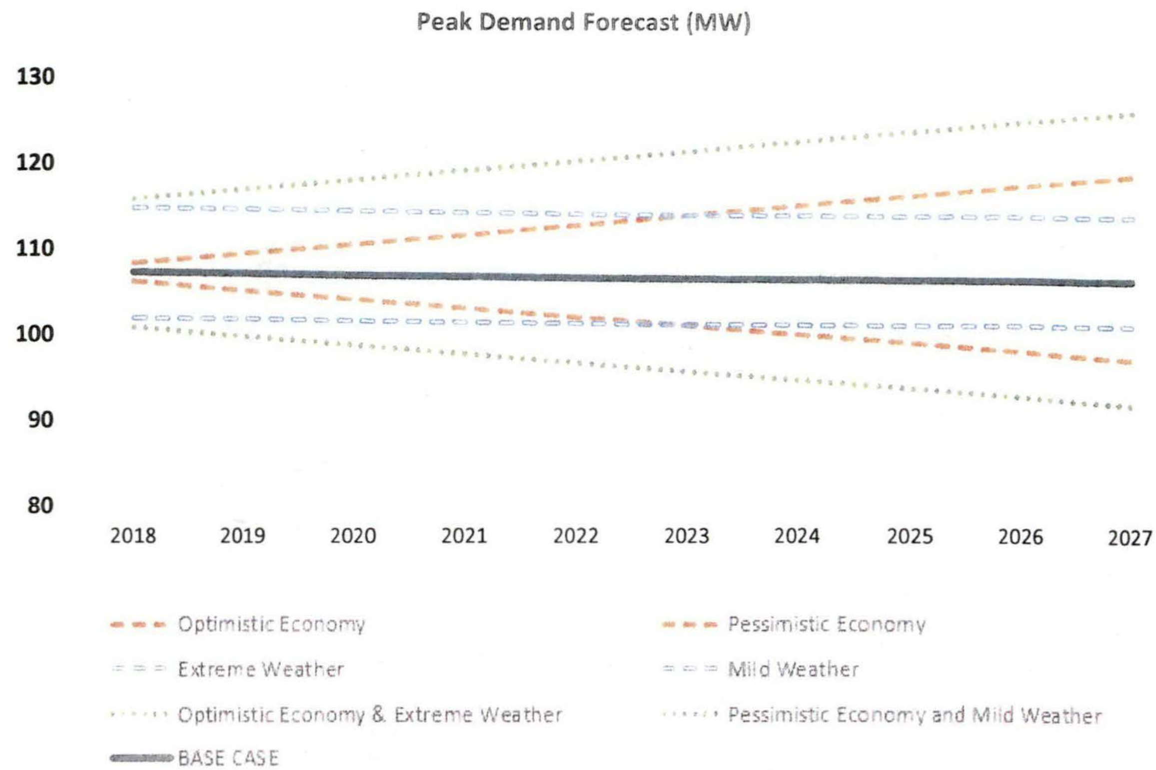


Figure 2-2: HMP&L Demand Forecast Scenario

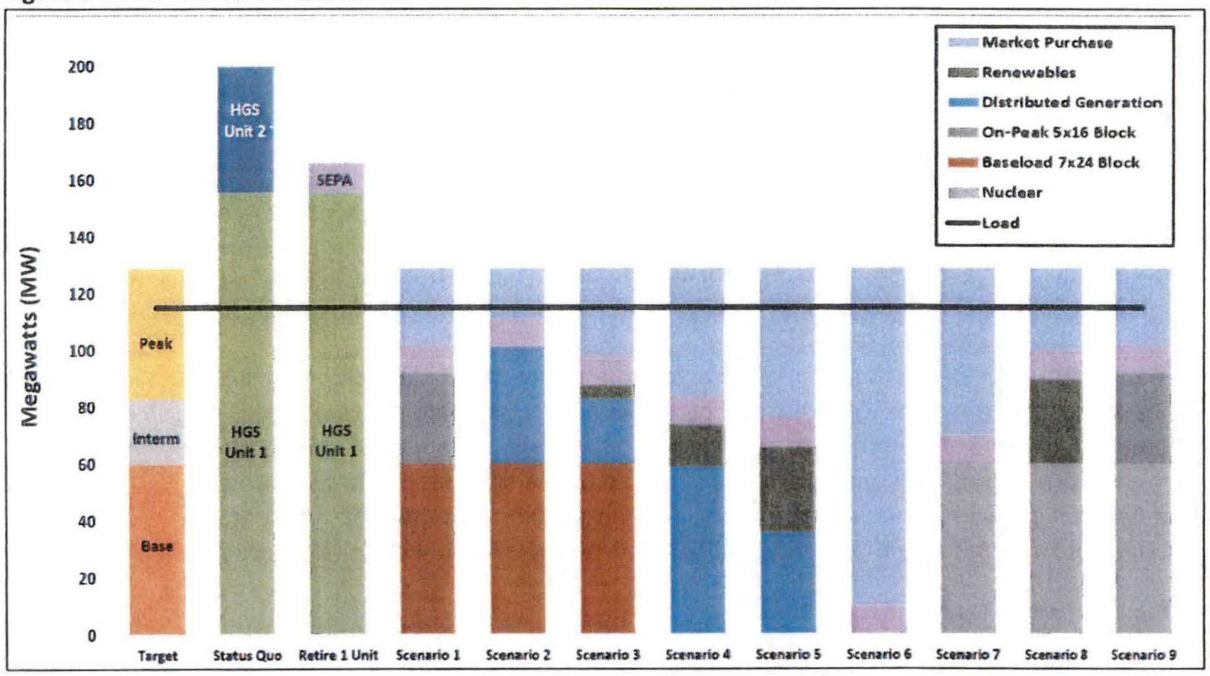


3.0 IRP Supply-Side Alternatives

HMP&L is interested in understanding how the economics of continuing to operate the HGS facility, either in a continued partnership with BREC (the "business as usual" case), or as the sole operator and recipient of 100% of the capacity and energy output of HGS, and therefore also responsible for 100% of the fixed and variable operational cost, compares to other potential generation resources and / or market purchases of capacity and energy. The IRP evaluation was designed to capture all relevant cost of continuing to maintain and own the HGS facility as well as the ownership and operational cost of all alternative resources or appropriate purchases of capacity and energy from the MISO market to serve all of HMP&L's load requirements.

This section of the IRP report documents the cost assumptions of the capital and operational cost for each of the resource scenarios, including continued ownership and operation of HGS. A visual summary of the various IRP supply side / generation resource scenarios is shown below in Figure 3-1.

Figure 3-1: IRP Resource Scenarios



3.1 HGS OPERATIONAL COST

HGS is comprised of two units, average rating of 156 MW each, and has been operating since 1971. Numerous upgrades and capital expenditures have been made over the years to ensure that the plant maintained a high availability and met all Federal/State environmental requirements. All of the historical expenditures are sunk costs and the IRP study is only evaluating the ongoing, continuing cost to operate the plant as well as capital cost investments necessary to meet the existing environmental upgrade requirements.

3.1.1 HGS Fixed O&M Cost

Several assumptions were made in this study for the fixed operations and maintenance ("Fixed O&M") expenses incurred in situations where HMP&L decides to operate one unit or both units without any collaboration with BREC. Given the assumption that it would be likely that HMP&L would not have a continued relationship with BREC in situations where HMP&L is continuing to operate and dispatch HGS as well as utilize 100% of the capacity and energy from the HGS facility, GDS requested a high-level O&M proposal from the PIC Group ("PIC"). PIC manages and operates power plants across the country and has extensive experience in operating coal plants and was able to provide GDS with an O&M estimate in February 2018 for the HGS facility. A comparison of BREC and PIC's estimated annual O&M labor cost for the HGS facility is shown below:

Table 3-1: Annual Labor O&M Cost

	Operation Type	BREC Cost	PIC Cost	Difference
1.	Two Units – Continuous	$14.392 M	$11.903 M	$2.489 M
2.	Two Units – Economic Dispatch (Seasonal)	$12.953 M	$10.742 M	$2.211 M
3.	One Unit – Continuous	$10.794 M	$9.002 M	$1.792 M
4.	One Unit – Economic Dispatch (Seasonal)	$9.355 M	$7.842 M	$1.513 M

BREC Labor O&M cost based on the 2018 HGS Operating Budget, with adjustments made for the economic and one unit operation scenarios. PIC Labor O&M cost adjusted for the other plant scenarios by the same pro rata allocation as BREC.

For scenarios where HMP&L has 100% responsibility for maintaining, operating, and dispatching the HGS facility, either both units or one unit, the study assumes that HMP&L's O&M labor cost will be based on the lower PIC estimate as opposed to the BREC cost. This is a conservative assumption as the PIC estimate has not been vetted thoroughly with PIC and may be too low but it does present the best possible outcome for the HGS retention scenarios. BREC's O&M labor cost are used in the "business as usual" scenario.

The annual Fixed O&M cost for HGS is projected to escalate at inflation, based, in large part, on expense amounts contained in the HGS 2018 FY operating budget. The annual Fixed O&M cost is assumed to fluctuate depending on whether the plant is dispatched on a continuous basis (i.e., high capacity factor) versus a more limited, economic dispatch as is currently being done due to prevailing market conditions. The two tables below summarize the Fixed O&M cost under these two basic dispatch scenarios for the two unit and one unit scenarios where HMP&L is responsible for 100% of the capacity and energy.

Table 3-2: Two Unit Annual Fixed O&M Cost

	FOM Expense Item	Two Unit Continuous	Two Unit Economic
1.	PIC Labor	$11.903 M	$10.743 M
2.	O&M Non-Labor	$7.950 M	$3.975 M
3.	FGD	$5.270 M	$2.635 M
4.	G&A Labor	$2.293 M	$2.293 M
5.	G&A Non-Labor	$0.997 M	$0.997 M
6.	Insurance	$0.421 M	$0.421 M
7.	**TOTAL**	**$29.730 M**	**$21.960 M**

Table 3-3: One Unit Annual Fixed O&M Cost

	FOM Expense Item	One Unit Continuous	One Unit Economic
1.	PIC Labor	$9.002 M	$7.842 M
2.	O&M Non-Labor	$3.975 M	$2.981 M
3.	FGD	$5.270 M	$1.976 M
4.	G&A Labor	$1.949 M	$2.293 M
5.	G&A Non-Labor	$0.848 M	$0.997 M
6.	Insurance	$0.421 M	$0.316 M
7.	**TOTAL**	**$21.913 M**	**$16.854 M**

3.1.2 HGS Variable O&M Cost

In addition to the Fixed O&M expenses, HGS has several variable components, including fuel, that are taken into consideration when accounting for all costs associated with operating and dispatching the plant. The following table summarizes all of the variable cost components that are used in the IRP evaluation study.

Table 3-4: HGS Variable Dispatch Cost

	2018 VOM Expense Item	Cost Per Unit
1.	Reagents	$4.93 / MWh
2.	Ash Disposal	$1.83 / MWh
3.	Allowances (on avg)	$0.18 / MWh
4.	Fuel	
	2018 Delivered Coal Cost ($/mmBtu)	1.80
	Average Heat Rate (MBtu/MWh)	11.479
	2018 Fuel Cost	$20.66 / MWh
5.	**TOTAL VARIABLE COST**	**$27.60 / MWh**

In the evaluation, future variable expenses were determined by escalating the reagents, ash disposal, and allowances by the annual inflation rate of 2.15%. The plant's fuel cost was a function of HGS' hourly dispatch in the economic dispatch model coupled with the appropriate heat rate (i.e. a higher heat rate at lower dispatch levels and a lower heat rate at higher dispatch levels) and the annual delivered coal cost pursuant to the applicable coal price projection scenario (described in more detail in Section 5.4).

3.1.3 HGS Short-Term Capital Cost

HGS is comprised of two units, average rating of 156 MW each, and are approximately 45 years old. There are planned capital upgrades in the immediate future as well as environmental upgrades that must be completed for the plant to continue operating beyond 2023. In all scenarios where the HGS plant was retired, no capital expenditures were made beyond 2018 and no decommissioning costs were incurred upon the retirement of HGS. For the scenarios where the HGS plant would continue to operate, it was assumed that all scheduled and expected capital and environmental upgrades would be completed based on the following cost estimates as shown in Table 3-5. All amounts shown are for the total plant.

Table 3-5: Major Planned Capital Expenditures (Total Plant)

	Major HGS Capital Item	Cost M$	Completion Year
1.	Turbine Overhaul – Unit 1	$8.0 M	2019
2.	Turbine Overhaul – Unit 2	$8.3 M	2021
3.	Dry Bottom Ash Under Boiler Conveyor	$20.9 M	2023
4.	FGD Wastewater Installation	$34.1 M	2023
5.	**TOTAL**	**$71.3 M**	**2023**

Estimates for turbine overhaul provided by HMP&L and environmental upgrade capital cost based on 2016 B&V study estimates. All cost shown in nominal dollars and escalation based on annual inflation rate of 2.15%.

3.1.4 HGS Decommissioning Cost

In scenarios where the HGS plant is retired and HMP&L pursues alternative generation resources, the IRP study assumes that HGS is "decommissioned" and that no significant expenditures occur in shutting down the plant and the existing equipment will be abandoned. Instead, these alternative scenarios assume that HMP&L will hire a security company to maintain appropriate security personnel at the site for an annual cost of approximately $775,000 (2020$).

3.2 ALTERNATIVES TO HGS

The IRP supply side alternatives to HGS represent a large cross section of generation technologies that are commercially viable today and, for the most part, would be able to be sited in or around HMP&L's service territory. The alternative options also include renewable resources, and the study assumes that wind projects could be acquired via a PPA with a wind developer. More importantly, this evaluation of alternative generation resources is not meant to suggest that these are the only alternatives available to HMP&L, but instead, are meant to address whether or not there are viable generation alternatives to continuing to operate the HGS facility either in partnership with BREC or without BREC.

At a high level, the cross section of alternative generation technologies includes reciprocating engines ("RICE"), smaller gas-fired generation (both peaking and intermediate generation), renewables, and modular nuclear. The modular nuclear is just a touchpoint for evaluating "non-gas" alternative resources within the IRP. And while this study assumes specific technologies from specific vendors (e.g. GE's LM2500), several manufacturers offer similar generating technologies and the information provided should be assumed to be generally applicable to other similar generating technologies from other vendors.

In addition to the generation resources, the IRP study also assumes that HMP&L could directly interact with the MISO market and third-party suppliers and purchase spot energy as well as enter into bilateral agreements for longer term energy or capacity purchases. All scenarios have some interaction with the MISO market and several scenarios have combinations of generation resources and block purchases from a third-party supplier at a fixed price.

Table 3-6 contains key assumptions for the alternative generation resources' capital cost, FOM, VOM, and heat rates. Please note that the capital cost reflects "installed capital cost" in 2018$ and includes Interest During Construction (IDC). Information for this table is comprised of several sources, including EIA's 2017 Annual Energy Outlook, SNL energy database (which is widely used in the energy industry and licensed for use by GDS), and other GDS client projects.

Table 3-6: Alternative Generation Assumptions

	Generation Technology	Unit Size (MW)	Capital Cost ($/kW)	FOM ($/kW-Yr)	VOM ($/MWh)	Heat Rate (MBtu/MWh)
1.	Wartsila (RICE)	9.2	1,232	12.56	6.70	8.40
2.	GE LM 2500	23.2	934	22.33	4.08	10.45
3.	GE LM 6000	59.0	1,426	36.17	3.93	7.56
4.	Solar	1.0	1,030	15.40	n/a	n/a
5.	Wind PPA	2.2	n/a	n/a	41.30	n/a
6.	Modular Nuclear	50.0	6,621	161.87	2.23	10.40

Capital cost for each project was escalated at the annual inflation rate of 2.15% in order to utilize nominal dollars for the year that the project achieves COD. The IRP study assumes that all gas-fired generation resources would achieve COD by January 2021 and the modular nuclear facility would be online by 2026.

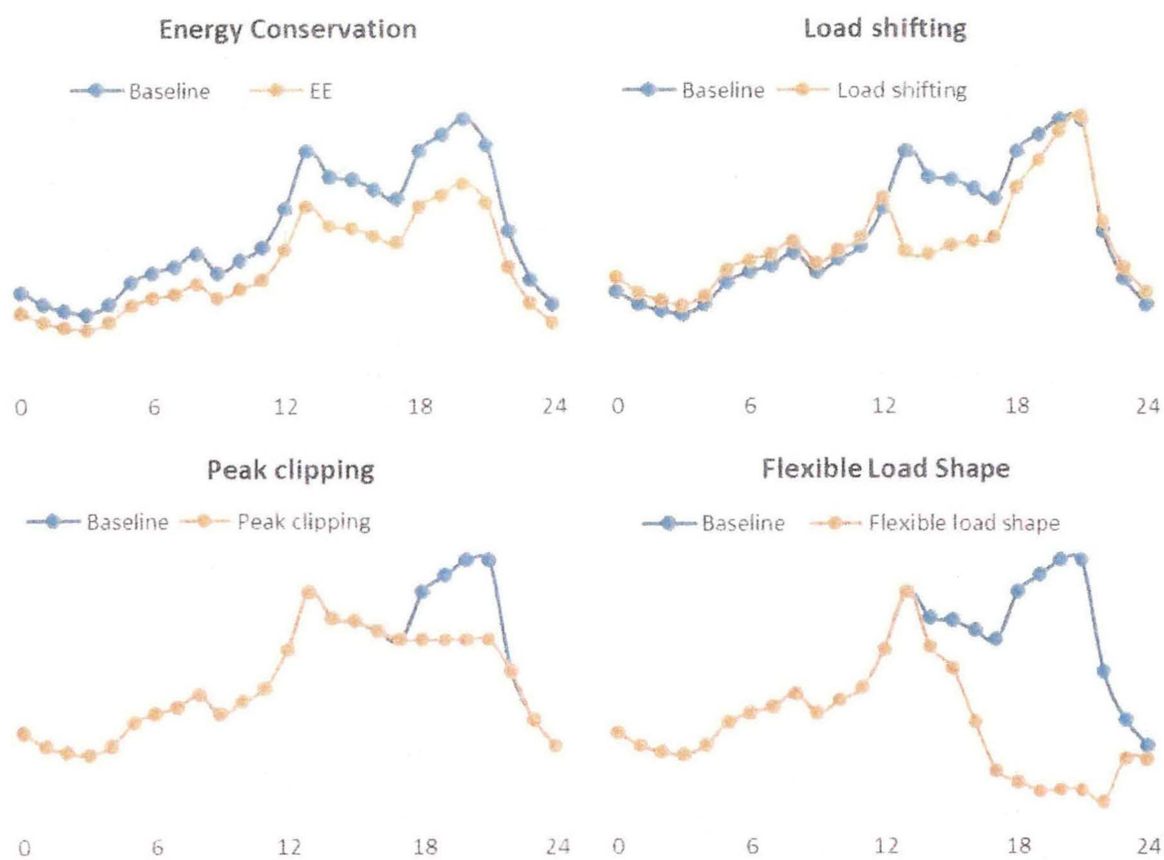
Projections of fixed O&M expenses and variable O&M expenses are also escalated by annual inflation rate of 2.15% and the gas-fired generation resources' fuel cost is dependent on the combination of unit heat rates and the prevailing delivered fuel prices (which is explained in more detail in Section 5.4). The total variable cost, or dispatch cost, of each generation resource is evaluated against the projected MISO market energy prices and modeled to either sell generation to MISO or to not dispatch and instead HMP&L purchases its daily load requirements from the MISO market. Additional details on the projections of MISO market energy prices, daily dispatch of the generation alternatives, and calculating the cost to serve HMP&L's load is described in Section 6.0.

4.0 DSM / Energy Efficiency Alternatives

Demand-side management ("DSM") and energy efficiency programs ("EE") have become critical elements of electric utility resource planning and enhanced customer service. DSM is a broad definition that includes energy efficiency as well as demand response ("DR"). Broadly speaking, utility DSM programs refer to the planning, design, implementation, and evaluation of activities engaged in by the utility to encourage their customers to modify the amount and timing of their consumption.

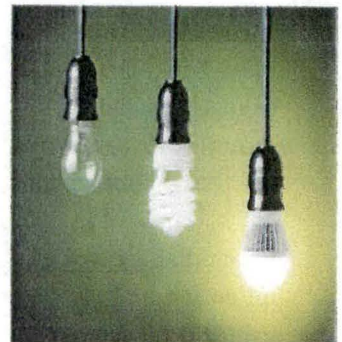
As part of this IRP study, HMP&L asked GDS to evaluate and identify some of the most cost-effective and beneficial DSM / EE programs that are used by electric utilities. HMP&L does not currently provide any DSM / EE programs for its retail customers. As such, GDS reviewed and identified DSM / EE programs that could provide the most benefit to HMP&L with respect to demand and energy savings but GDS did not assume, for purposes of this IRP study, that HMP&L would pursue any of these programs and that there would be demand and / or energy consumption reductions (and benefits) relative to the base forecast. As such, all supply-side alternatives were designed to meet HMP&L demand and energy needs as identified in the base load forecast. With respect to how electric utilities utilize DSM programs, the figure below shows how different types of DSM strategies may affect the load shape of retail customers or an entire system.

Figure 4-1: Examples of DSM Impact on Load Shape



Historically DSM has primarily been used to provide cost-effective energy and capacity solutions as part of a holistic and integral power supply planning process. However, electric utilities are now looking to DSM to help enhance customer service as well.

The American Council for an Energy Efficient Economy (ACEEE) ranked Kentucky as the 28th most efficient state in 2017, according to the metrics used by ACEEE to publish its annual State Energy Efficiency Scorecard.[1] However, Kentucky ranked second among 11 states in the southeast, trailing only Florida. Therefore, while only in the middle of the pack nationally, Kentucky is a leading state for energy efficiency in the region.



According to the U.S. Department of Energy (DOE) Energy Information Administration (EIA), among the state's utilities actively engaged in DSM in 2016, they achieved more than 330,000 MWh in energy savings and more than 400 MW in capacity savings. The energy savings represent about 0.5% of the aggregate forecasted energy savings among these utilities and cooperatives.

The energy and demand savings achieved by these entities originated from a variety of program types, targeting various customer segments. The energy savings were nearly evenly split across the residential and non-residential (commercial and industrial) sectors. The leading program types addressed residential lighting and appliances, residential behavioral changes (home energy reports), and non-residential energy efficiency upgrades through rebate offers. The capacity savings were achieved largely by non-residential custom measures and demand response programs targeting both residential and non-residential customers. Non-residential DR programs are offered in variety of manners, including the use of standby generators, in which the customer operates using a generator for its electric needs to pre-determined hours or during emergency events called by the utility.

GDS has reviewed the most recent plans of Kentucky municipal utilities and cooperatives to determine how the market for DSM may be changing. There are several factors that are expected to suppress the growth of DSM. The rapid adoption of energy efficient technologies in the absence of utility intervention, low load growth, and low avoided costs for energy and capacity, are all general trends changing the dynamics of DSM opportunities. However, significant opportunities do remain in the near-term. LED lighting, especially in the residential sector, offers the most potential for cost-effective energy savings over the next few years, before the EISA backstop provision takes effect.[2] From a demand response perspective, smart thermostats in the residential sector, and customized curtailment plans for large non-residential customers, offer significant opportunities to achieve capacity savings.

[1] The 2017 State Energy Efficiency Scorecard, ACEEE. http://aceee.org/research-report/u1710

[2] The Energy Independence and Securities Act of 2007 (EISA) includes a "backstop" provision where any bulb sold after 2020 will need to meet a 45 lumens per watt standard.

In our opinion, there are several "low-hanging fruit" options that HMP&L should consider if it is interested in providing DSM options to its retail customers. These include the following demand response and energy efficiency opportunities:

- **Industrial customized load curtailment** – this type of program is likely to be the most economical and easiest to implement to achieve DR savings, and given the nature of HMP&L's retail customer base, it may be the most practical option. It may be possible to save 1 to 2 MW per large industrial customer.

- **WIFI-enabled ("smart") thermostats** – this is a more advanced (aka, leading edge) offering, but it could be made available to residential and non-residential customers. These measures could be offered to achieve energy savings, capacity savings, or both. Savings may approach 1 kW per residential customer. As an alternative to smart thermostats, HMP&L could consider using switches to control air-conditioner or water heating loads among residential customers. This alternative would be a less expensive option than smart thermostats.

- **Residential lighting giveaway** – this is the simplest and easiest residential energy efficiency program option for producing cost-effective benefits and could quickly fill a significant market opportunity in HMP&L's service territory as well as enhance customer satisfaction (and interaction) with the utility.

- **Non-residential audit direct installation** – this type of program typically focuses on lighting, HVAC, and refrigeration among small commercial customers. It can be more expensive than rebate or giveaway programs, but does enhance the customer experience and satisfaction with the utility.

- **Non-residential custom incentives** – this type of program is useful among smaller customer bases because it is better able to serve a customer's unique needs than a prescriptive incentive program. There are added administrative costs associated with approving custom incentive applications, but this type of program can enhance the customer experience and satisfaction with the utility.

The utility cost to provide DSM services to its customers varies widely, depending on the characteristics of a utility's customers and the type of programs it offers. For instance, demand response programs can cost anywhere from $20/kW-yr to $100/kW-yr. Utilities that offer energy efficiency programs typically spend, on average, about 1% of their revenue on the programs, and achieve annual energy savings ranging from 0.2% to 1% of the forecasted annual sales.

So, what is next for HMP&L in terms of DSM? The figure below shows the conceptual framework that utilities follow in terms of planning, developing, and assessing the performance of a portfolio of DSM programs and activities. The planning component consists of data gathering and analysis in order to better understand the DSM marketplace for a specific utility. Potential studies assess the level of energy efficiency or demand response savings potential over a specified timeframe. Potential studies also help identify measure types or program types that may be most critical for success. Baseline studies are useful for gathering market data which help inform key potential study assumptions regarding the baseline equipment saturations, as well as the percentage of equipment and other characteristics. Market research and reviewing best practices are also helpful planning activities that will enable utilities to be ready to develop or improve upon its portfolio of DSM programs.

Figure 4-2: Examples of DSM Planning, Portfolio Development, and Assessment Activities

Planning	Portfolio Development	Assessment of Performance
Potential Studies	Develop Avoided Costs	Evaluation
Baseline Studies	Determine Cost-Effectiveness	Measurement
Market Research	Design Programs	Verification
Review of Best Practices	Implement Programs	Recommendations

Not each of these activities is a requirement to effectively operate DSM programs and achieve energy and capacity savings – the specific engagements are determined based on a utility's needs and regulatory considerations. Should HMP&L decide to continue to explore DSM options and pursue DSM in the future, GDS would be available to assist HMP&L to determine appropriate next steps to help it strive to reach its goals.

5.0 Major Evaluation Assumptions

HMP&L's IRP process evaluates the net present value of alternative resource scenarios with HMP&L's continued ownership in HGS (one unit or both units) as well as the "business as usual" scenario whereby HMP&L continues to own HGS and BREC continues to operate the plant and purchase the excess capacity and energy from HMP&L. The evaluation process captures capital cost, fixed carrying charges, variable related expenses, and other related cost for each of the generation resource scenarios. In addition to the forecasted capacity and energy needs, there are numerous assumptions that are utilized in order to evaluate all of the alternatives on an equitable basis. The major assumptions are described in this section.

5.1 INFLATION AND ESCALATION RATES

The general inflation rate was based on EIA's 2017 Annual Energy Outlook and is assumed to be 2.15% per annum over the 20 year study period. This inflation rate is used to escalate all capital construction costs, fixed O&M expense, nonfuel variable O&M expenses, and capital cost of major environmental / maintenance expenditures during the 20 year period of the study.

5.2 DEBT FINANCING ASSUMPTIONS

The evaluation assumes that HMP&L will issue new debt to finance all new generation additions, or major capital expenditures, using 100% debt. The interest rate of that debt is assumed to be 4.0% and the financing term for all new generation resources was assumed to be 25 years. For simplicity and comparability among generation resources, IDC was assumed to be $100/kW for the non-nuclear generation resources and $250/kW for the modular nuclear resource and these IDC estimates are included in the capital cost information described in Section 3.

5.3 PRESENT WORTH DISCOUNT RATE

Since the new debt interest rate assumption was 4.0% the study also assumes that the discount rate is 4.0%. The discount rate is used in all net present value calculations to bring all future cash flows during the term of the study to a present value basis.

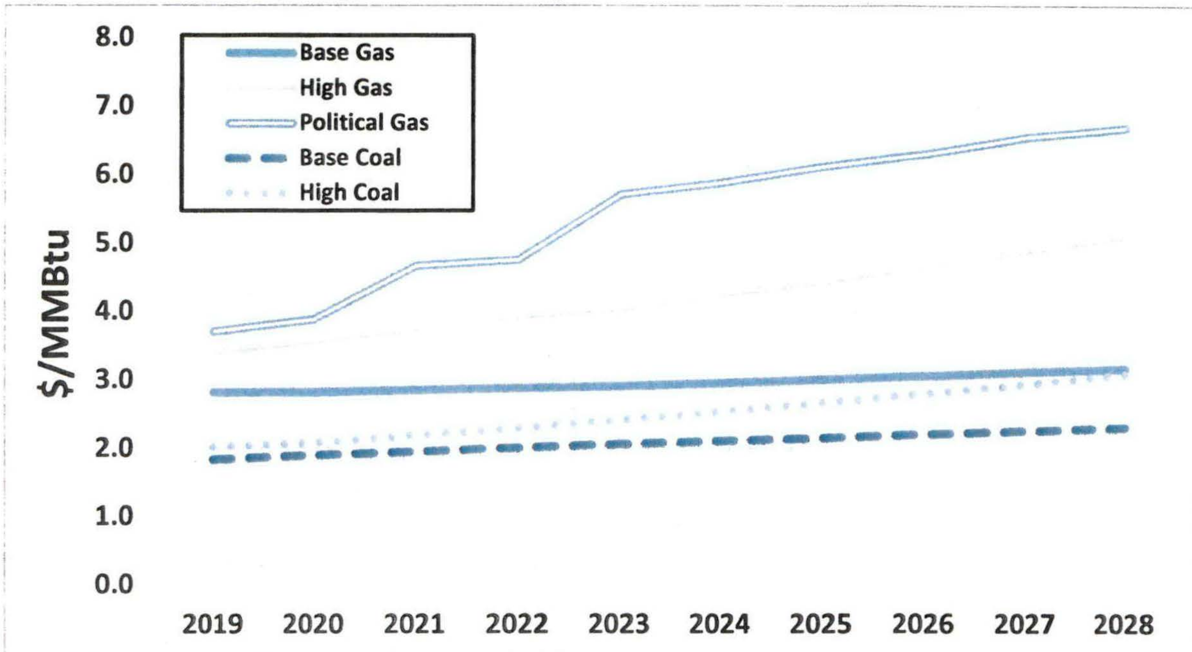
5.4 FUEL PRICE FORECAST

Given the uncertainty and volatility in the historical fuel prices, this study process used three different natural gas price scenarios coupled with two different coal price projections. The three gas price scenarios were labeled Base Gas, High Gas, and Political Gas, and have an annual average price equal to $3.20/mmbtu, $5.38/mmbtu, and $6.83/mmbtu, respectively.

The Base Gas pricing curve was developed using the current average of NYMEX Henry Hub forwards contract values with low escalation thereafter. The High Gas curve reflects the outlook of the 2017 EIA AEO reference case gas curve, which contained higher gas price values because of additional market pressure on fuels that existed at the time of the EIA report. Finally, the Political Gas curve was developed to reflect the potential for extreme increases in gas prices due to unforeseen geopolitical events, changes in legislation or regulations that create additional environmental or technical gas production requirements, and / or market externalities, such as increased LNG exports, that change the underlying fundamentals for natural gas or coal. The curve includes an initial gas pricing point reflective of the High Oil reference case from the 2017 EIA report as well as subjective, larger increases in 2021 and 2023.

Base and High coal price curves of $2.36/mmbtu and $3.38/mmbtu, respectively, were chosen based on current delivered coal price costs and higher costs that would exist in high gas price scenarios. A comparison of gas and coal prices from the analysis are shown in the chart below. All gas and coal pricing is in nominal dollars.

Figure 5-1: Natural Gas and Coal Price Fuel Projections



5.5 MISO MARKET ENERGY & CAPACITY PRICES

The IRP study assumes that HMP&L will be an active participant in the MISO energy market vis-a-vis buying energy from MISO for daily load obligations or selling generation from its resources to MISO. For modeling purposes, the IRP study assumes all generation resource alternatives are dispatched based on market economics (i.e. the worst case scenario is that HMP&L's load cost is equal to the average fuel cost of its generation portfolio) and not to explicitly serve HMP&L's daily load requirements. To the extent that HMP&L generation resources are dispatched in the MISO market then the "net margins" are recognized as benefits that reduce the overall cost of owning the generation asset.

5.5.1 Energy Price Projections

The MISO market provides the ability for HMP&L to purchase hourly energy for all of its load requirements as well as the opportunity to buy "forwards" or bilateral agreements for energy blocks from third-party suppliers that can be utilized to reduce purchases from the MISO market. In addition to buying energy from MISO for load requirements, any scenarios where HMP&L owns generation requires a projection of MISO energy prices to determine the value of the alternative resource generation. The IRP study had to create energy pricing for both MISO hourly energy purchases / sales as well as potential third-party block purchases. The process for creating these projections is described in Section 6.0.

5.5.2 Capacity Price Projections

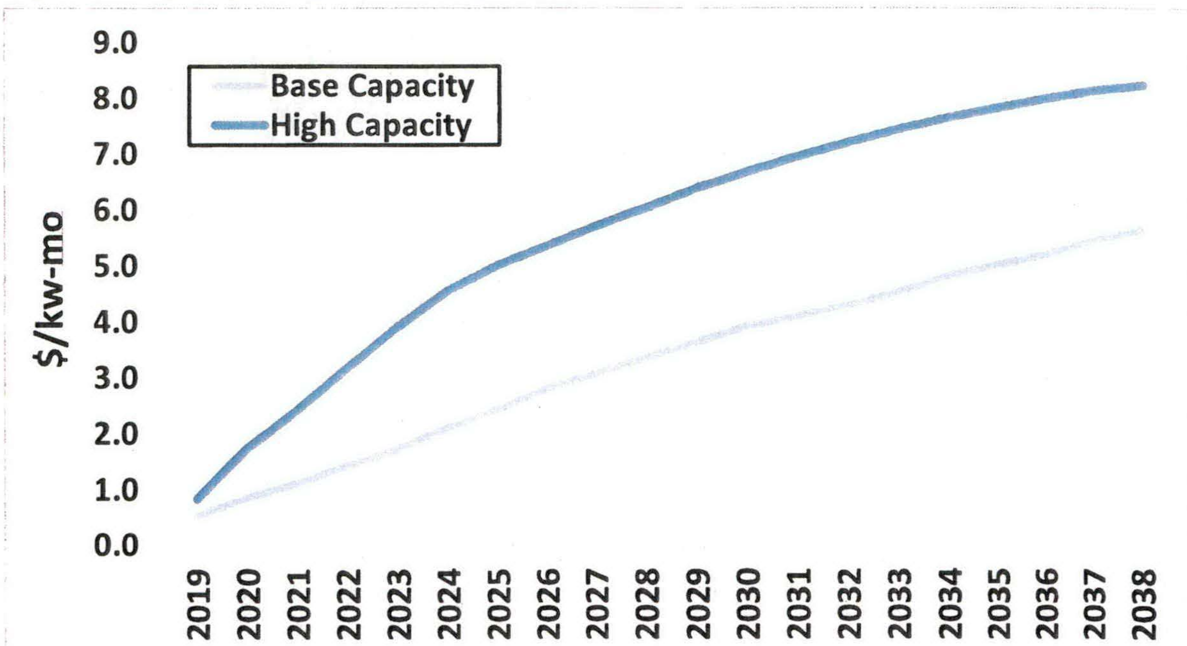
Capacity price projections were necessary in order to determine the cost of incremental capacity necessary to meet HMP&L's MISO load requirements as well as determine the value of excess capacity sales to MISO (excess to meeting HMP&L's MISO load requirements). Capacity price projections are based on a fundamental approach using the estimated cost of incremental new capacity to the MISO region. Historically, MISO capacity auction prices have been very low for Zone 6 (and most of the MISO footprint) and the most recent capacity auction for PY 2018/19 (completed on April 12, 2018) produced a capacity price of $10.00/MW-Day or $0.30/kW-month.

Recently, GDS has completed MISO capacity price projections for other clients and GDS' proprietary capacity pricing model was utilized in the HMP&L IRP process. At its core, the GDS capacity pricing model identifies incremental capacity needs in MISO based on future capacity margins and operating reserves and projects the fixed cost of those incremental capacity resources less the variable energy margin benefits that could be obtained in the MISO market.

Two capacity pricing scenarios were developed for the HMP&L IRP based on different underlying assumptions: (1) a base case reflecting the continued proliferation of low demand growth across the region and continued penetration of solar resources and wind resources and (2) a high capacity price scenario that assumes load growth returns to normal levels after LED, appliance, and home construction energy efficiency benefits are fully recognized (e.g. no more incandescent bulbs to replace) and a beneficial technology disruption occurs, such as retail acceptance of electric vehicles.

The two capacity price scenarios are used as a sensitivity to evaluate all generation resource alternatives to understand the implications of varying capacity prices during the study period. The average capacity price over the study period for the Base scenario was approximately $3.20/kW-mo and $5.66/kW-mo for the High price scenario. The capacity price projections are shown in the chart below.

Figure 5-2: Capacity Pricing for Base / High Cost Scenarios

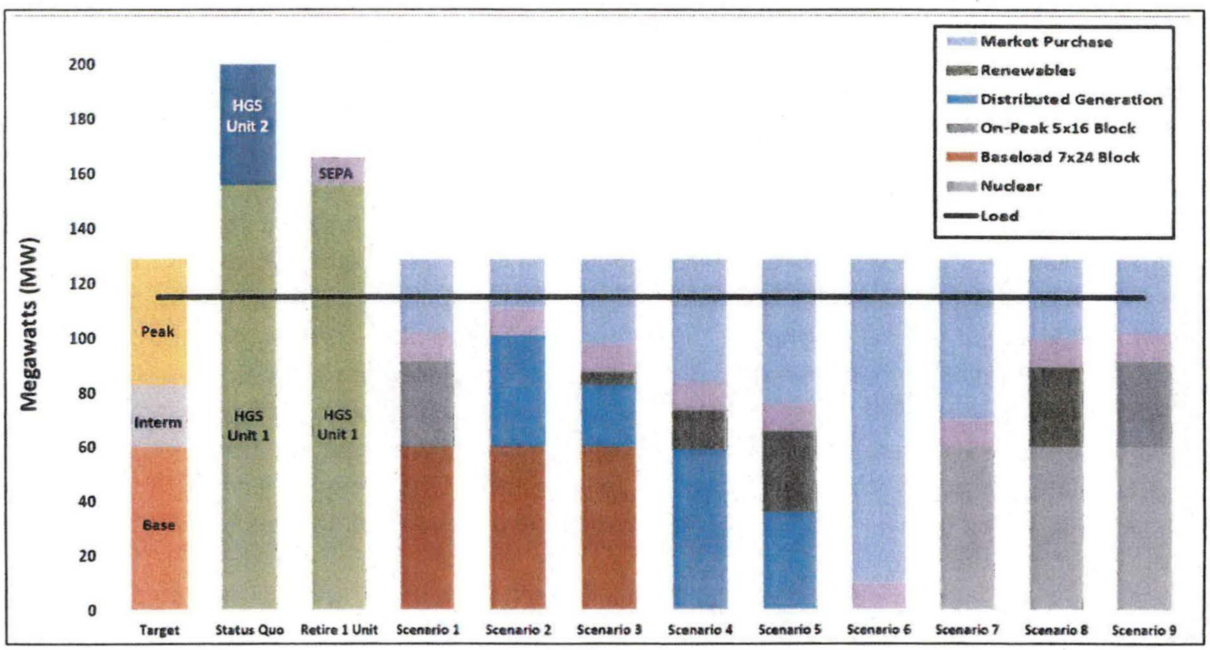


6.0 Dispatch Modeling Methodology

The IRP study utilized an hourly economic resource dispatch model to evaluate the annual cost and market-related benefits of HMP&L's existing coal-fired generation as well as the generation resource alternatives. The economic dispatch model incorporated HMP&L's base load forecast, as described in Section 2.0, to determine the hourly energy requirements and the combination of power supply resources and MISO market energy necessary to meet those requirements. The combination of the economic dispatch model results and the relevant generation resource fixed carrying cost and fixed O&M expenses provide the total cost necessary to identify the optimal generation resource scenario to serve HMP&L's supplemental demand and energy requirements.

HMP&L's projected capacity requirements to serve its total load requirements, including reliability planning reserve requirements in MISO, is approximately 115 MW. The IRP study includes a variety of alternative resource scenarios to identify a specific, or a combination, of portfolio resources that provide the most benefits, at the lowest cost volatility, under a range of sensitivities (e.g. low capacity prices, high fuel prices). The IRP study process uses a diverse resource approach to serve HMP&L's total load requirements in order to provide an inherent risk management program that insulates HMP&L from serious exposure to a single large generation unit long-term outage, high fuel prices, or PPA contract termination (for a large portion of load). The study utilized commercial viable generating technology options such as combustion turbine, combined cycle, reciprocating engines, and renewables, most of which could be sited within HMP&L's service territory. Modular nuclear is not a readily available commercial technology but was used to represent the benefits of a "non-gas" base load resource. The chart below identifies the eleven alternative resource scenarios as compared to the "business as usual" case.

Figure 6-1: IRP Resource Scenarios



As can be noted from Figure 6-1, the alternative resource scenarios vary greatly in the resource mix used to fulfill HMP&L's capacity and energy requirements. In general, the scenarios can be classified into three categories: (1) HMP&L continues to rely exclusively on its existing generation resources, (2) HMP&L significantly relies on energy and capacity from either the MISO market and/or 3rd party block purchases, and (3) new generation assets are built to hedge a significant portion of HMP&L's load requirements.

6.1 STUDY PERIOD

The IRP dispatch analysis was performed over a 20-year period beginning in 2019 and ending in 2038. Construction lead time was taken into consideration depending on the chosen generation technology. For simplification, RICE, combustion turbines, and combined cycle units achieved a COD beginning in 2021 while the modular nuclear resource achieved a COD by 2026. GDS recognizes that the nuclear COD is aggressive but wanted to be able to incorporate any meaningful benefits from this resource in the 20 year planning horizon.

6.2 MISO MARKET PROJECTIONS

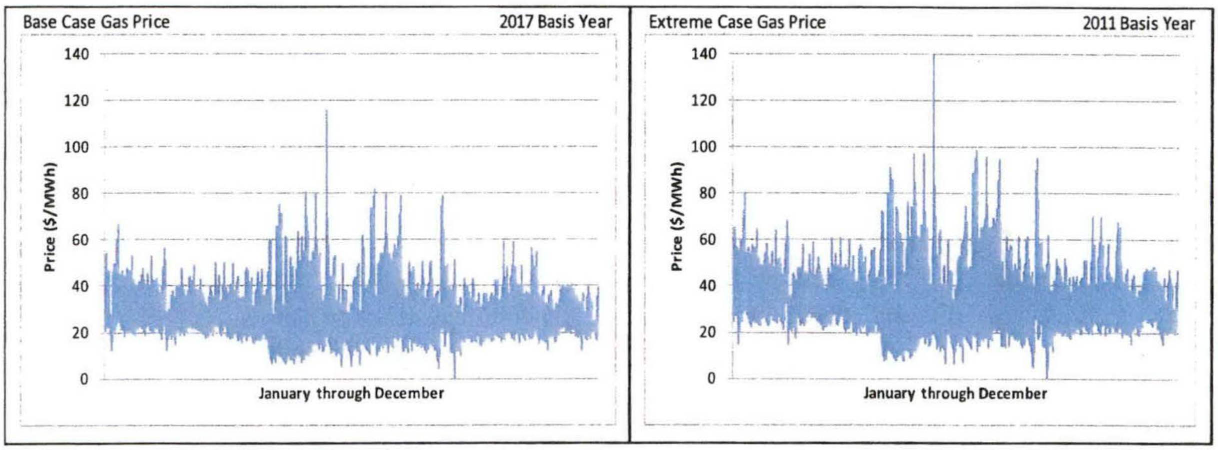
In order to model the inherent volatility in hourly market prices, the model uses a two-step method to project market energy prices. First, average monthly market energy prices were projected using the relevant gas price projection assumption (i.e. base, high, or political). This first step establishes the basic overall level of market energy prices. Next, the model applies various historical MISO hourly price shapes to the average market energy price established in the first step to introduce hour-to-hour variability. Each step is described in more detail below.

To project average hourly electricity market prices for future months, the model applied a linear regression analysis to the projected gas prices. The regression models average monthly day-ahead MISO market price as a function of average gas prices in the same month. The key assumption in this analysis is that historically, gas-fired generation represents the marginal / incremental energy price in the vast majority of hours, and will continue to be the marginal resource over the 20 year study period. The linear regression equation relied on historical gas prices from 2011 through 2017. Projected average monthly electricity market prices were based on the regression equation and the three gas price forecast scenarios (base case, high case, and political case).

Once the average monthly market price for each gas price scenario was developed, the model generated hourly price projection scenarios. Hour-to-hour day-ahead market prices can be quite volatile depending on a large number of variables, such as planned and unplanned plant outages, uncharacteristic weather, unexpected loads or peak demands, planned and unplanned transmission outages, BTM generation, and unanticipated output of wind generation. To appropriately represent volatility in the IRP models, there were four historical hourly price curves used to generate price profiles for each future year and for each gas price scenario. All in all, that means there were twelve different hourly price projections for each year of the study horizon. Historical price shapes were adjusted to align weekdays and weekends in the future year to ensure weekend/weekday pricing patterns remain intact. The hourly price curves in each month from a historical year (a "basis year") were mapped to future projected average hourly price (as described in the first step of this analysis).

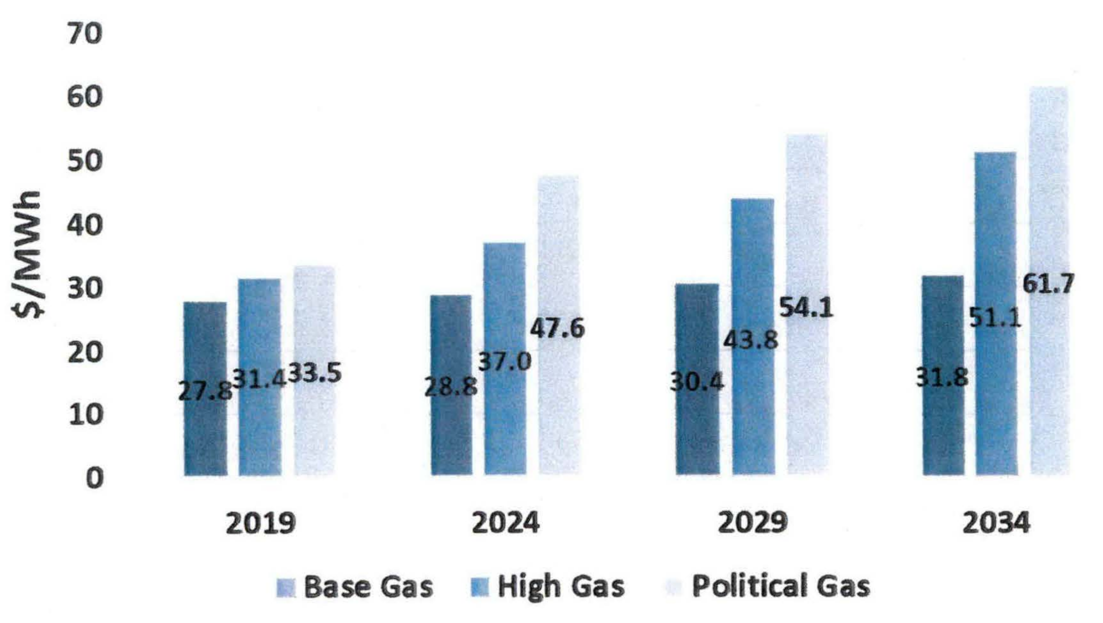
2011, 2013, 2014, and 2017 are the historical years that are good indicators of various levels of volatility in MISO market energy prices. The twelve scenarios (four historical years times three gas price forecasts) provide for a range of possible market price outcomes, taking gas price uncertainty, intraday and day-to-day market price volatility into account. The two charts below, which show 2019 hourly chronological LMP projections under two different gas scenarios, were created utilizing the 2011 and 2017 basis years. As the illustration demonstrates, 2011 is a more volatile year and is used to create the extreme gas price LMP curve while 2017 represents a less volatile year and was used to shape the base gas price LMP curve.

Figure 6-2: 2019 MISO Market Energy Price Projection Examples



LMP projections were thus produced for subsequent years for each gas price sensitivity utilizing the methodology described above. The results of the hourly LMP projections are load weighted and rolled up to annual values (for illustrative purposes only) in the subsequent figure below. The actual hourly LMP projections are utilized in the dispatch model as described in section 6.4 of this report.

Figure 6-3: Average Annual MISO Energy Prices by Gas Scenario



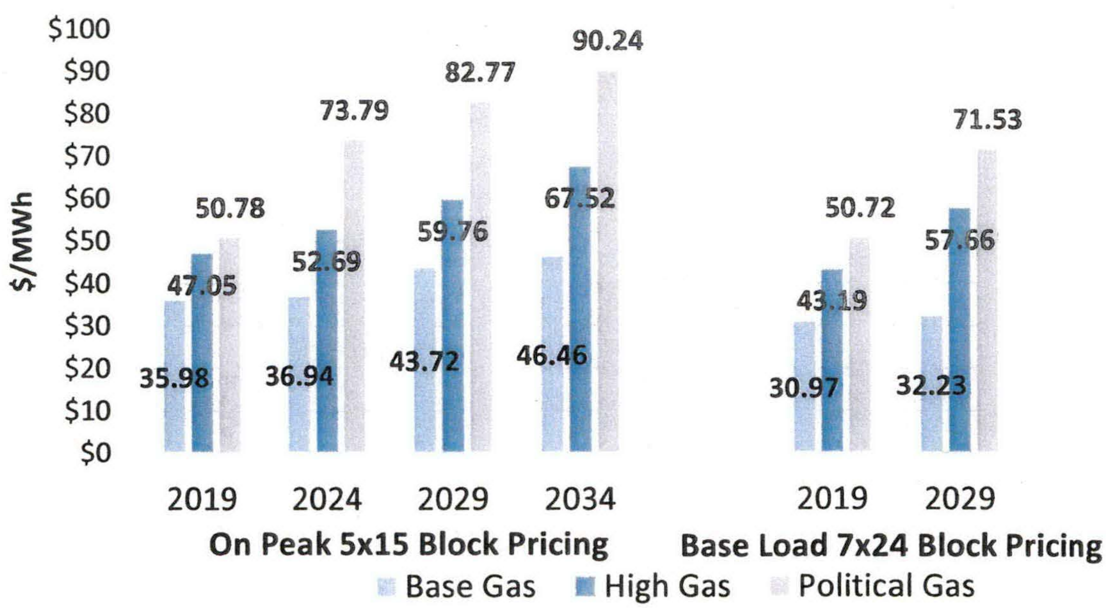
6.3 THIRD-PARTY BLOCK PURCHASE

The IRP study included two market purchased power products as a part of the scenario analysis: (1) a 7 x 24 block and (2) a 5 x 16 block. These two types of energy blocks are commonly purchased / traded in the energy markets and are also very liquid blocks to purchase in MISO from third-party suppliers. The benefit of these energy block purchases for HMP&L is the ability to "lock in" a certain portion of their overall energy requirements at a fixed price.

For purposes of determining the price of these energy blocks in future years, pricing of historical and current forward contracts at the Indiana Hub were compared to Henry Hub gas prices and then correlated to IRP gas price sensitivities. An anticipated market premium based on supplier's risk of providing the fixed price block to HMP&L, which differs by block type, was added to reflect current observed market pricing. In addition to the price premiums, a congestion component was included based upon the historical relationship between Indiana Hub and HMP&L's load node (the historical congestion component was negative so it lowers the energy block price).

Based on the appropriate alternative resource scenario where HMP&L is purchasing energy blocks from third-party suppliers, the study assumes that HMP&L will purchase 7 x 24 blocks over a 10 year term (i.e. two 7 x 24 blocks during the 20 year study period) and will purchase 5 x 16 blocks over a 5 year term. Thus, the final step in the energy block pricing projection process was to escalate the total block prices over 5 year intervals for the 5x16 blocks and 10 year intervals for the 7x24 blocks. The escalation rate was tied directly to the annual gas price escalation used in each gas price sensitivity (average over the appropriate 5 or 10 year term).

Figure 6-4: Average Annual Energy Block PPA Prices by Gas Scenario

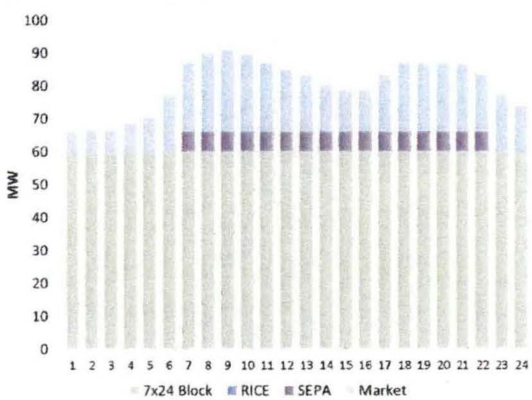


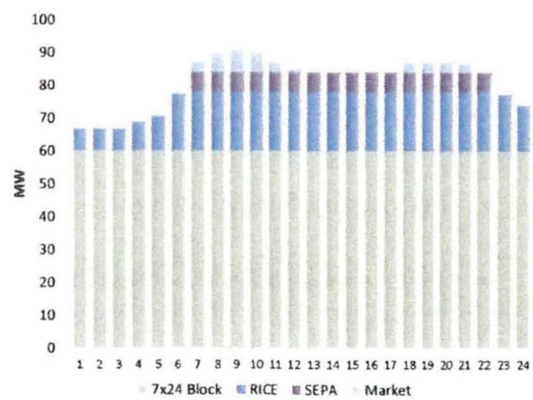
6.4 DISPATCH MODEL FUNCTIONALITY

The economic hourly dispatch model conducts daily dispatch assessments for generation resources while considering MISO market economics and HMP&L's projected hourly load forecast curves. Prior to being used in the hourly dispatch model, the hourly load forecast is adjusted to net HMP&L's SEPA hydro allocation, as well as any wind and solar generation, and modular nuclear generation as appropriate for the relevant resource scenario. This is done to reflect the zero, or very low, variable dispatch cost of these resources. In addition to the zero, low variable cost resources being netted from HMP&L's daily load, for scenarios where HMP&L was purchasing blocks of energy (either 7 x 24 or 5 x 16 blocks) then those energy quantities were also used to reduce HMP&L's load.

Once pre-dispatch resources were netted out, the hourly dispatch model began a daily optimization heuristic that looked at all possible combinations for a given set of resources, by scenario, for meeting the remaining daily load requirements. The model compared hourly market LMP prices with each generator's given variable cost profile and run time characteristics to determine the most economical resource sequence to meet daily load needs. Generators were modeled to include start fuel costs, minimum and maximum capacity states with corresponding heat rates, variable O&M expense, minimum run time, minimum down time, and a maximum number of starts per day.

Figure 6-5: Daily Optimization Visualization





In the illustration above, dispatch output for a given scenario resource mix that includes a 7x24 block, Wartsila RICE generation, and market purchases is illustrated. The 7x24 block and SEPA are included automatically, but the decision to serve the remainder of the load results in an economical calibration of the Wartsila RICE dispatch versus MISO market purchases. Once all possible dispatch sequences are tested across the variable costs for these two resources, the optimal solution is found to include a dispatch of the Wartsila RICE units and then a purchase from the MISO market across a subset of hours. These types of daily results are dynamic in nature, dependent upon the hourly load needs and the variable cost of generation or market purchases from the hourly LMP projections.

In addition to adhering to generator operating constraints, the proprietary dispatch model also minimizes the arbitrage ability of generation to ramp up and down excessively to capture short hourly market LMP spikes as this is generally not the goal of prudent utility planning practices nor the primary reason for installing generation. The least cost dispatch solutions from the model were subsequently combined with the additional fixed cost considerations for each scenario to achieve a holistic view of the results in comparison with each other. The results of the analysis are further described in Section 8.0 of this report.

7.0 Long Range Financial Forecast Model

HMP&L's most recent pro forma financial statement was used as the basis to develop a 10-year long range financial forecast (LRFF) in an effort to determine financial impacts to HMP&L of each of the power supply scenarios while maintaining certain financial metrics as targeted by HMP&L management and /or required by existing debt covenants. The original pro forma was modified to capture and delineate the costs and revenues specifically associated with the various power supply scenarios while maintaining status quo for all revenues and expenses not related to power supply or electricity sales to customers (Appendix A). Given the timing of this study, and the anticipated time and effort required to extinguish the existing arrangement with BREC, the BAU case was assumed to continue throughout 2019 in all scenarios and beginning in 2020 the impacts of the alternative resources scenarios, including the scenario where HMP&L utilizes 100% of the HGS capacity and energy for one or both units.

For each of the respective power supply scenarios, revenues and costs associated with market interaction in MISO, fixed and variable O&M and fuel costs for generation resources, and purchase power costs for structured market products were imported into the LRFF from the economic dispatch model. Capital-related items (i.e., depreciation, interest, and principal payments) associated with major capital additions at Station 2 and all new generation resources were assumed to be funded by issuing new bonds and financed over a 25-yr period under a level principal debt payment structure at an interest rate of 4.0%.

To provide a consistent method of comparing the LRFF impacts of the power supply scenarios, revenues from power sales for each of the scenarios were determined based upon the following constraints as identified by HMP&L and applied on an annual basis throughout the forecast period:

- Net income of not less than zero -$0-
- Target cash balance of not less than $20 million
- Minimum DSC of 1.0 for scenarios that do not contain new bond issuances (Scenarios 1 & 6)
- Minimum DSC of 1.25 for scenarios that do contain new bond issuances
  Note: the "Business-as-Usual" case assumes a targeted net income of $4 million annually as determined by HMP&L.

The results of the LRFF scenario analysis can be summarized by calculating an implied annual rate (see Figure 7-1) and a 10-yr levelized rate (see Figure 7-2) associated with power sales for each power supply scenario.

Figure 7-1: LRFF Scenario Comparison: Annual Rate

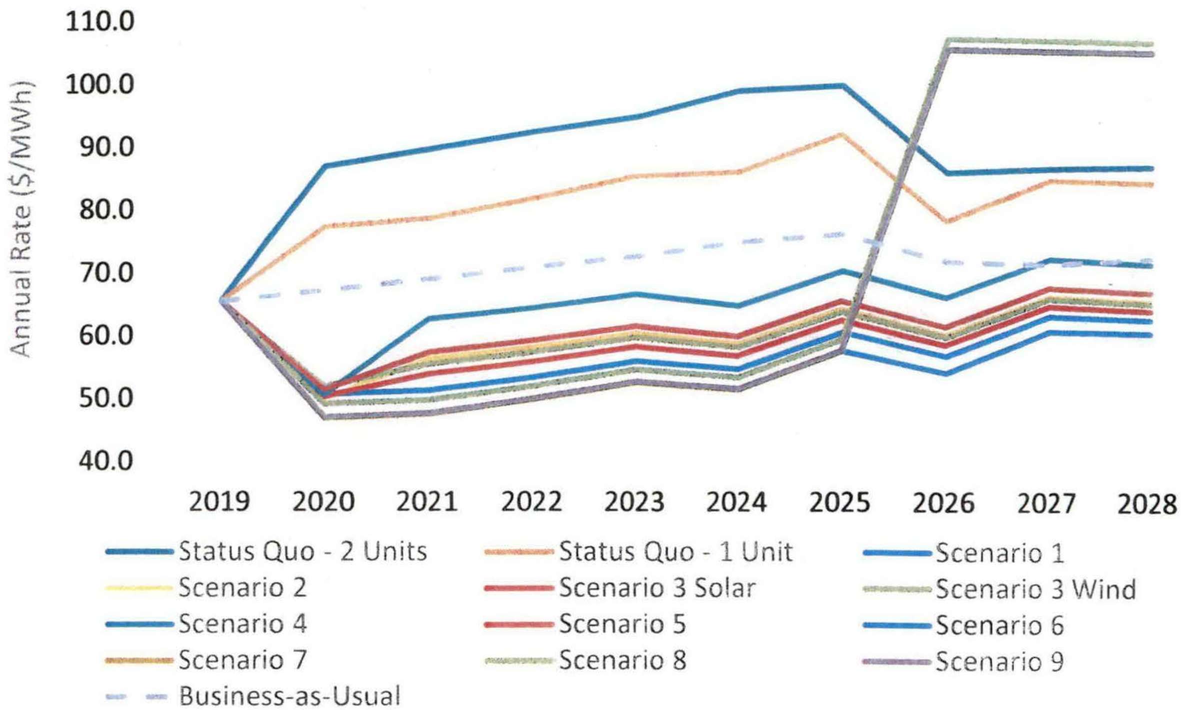
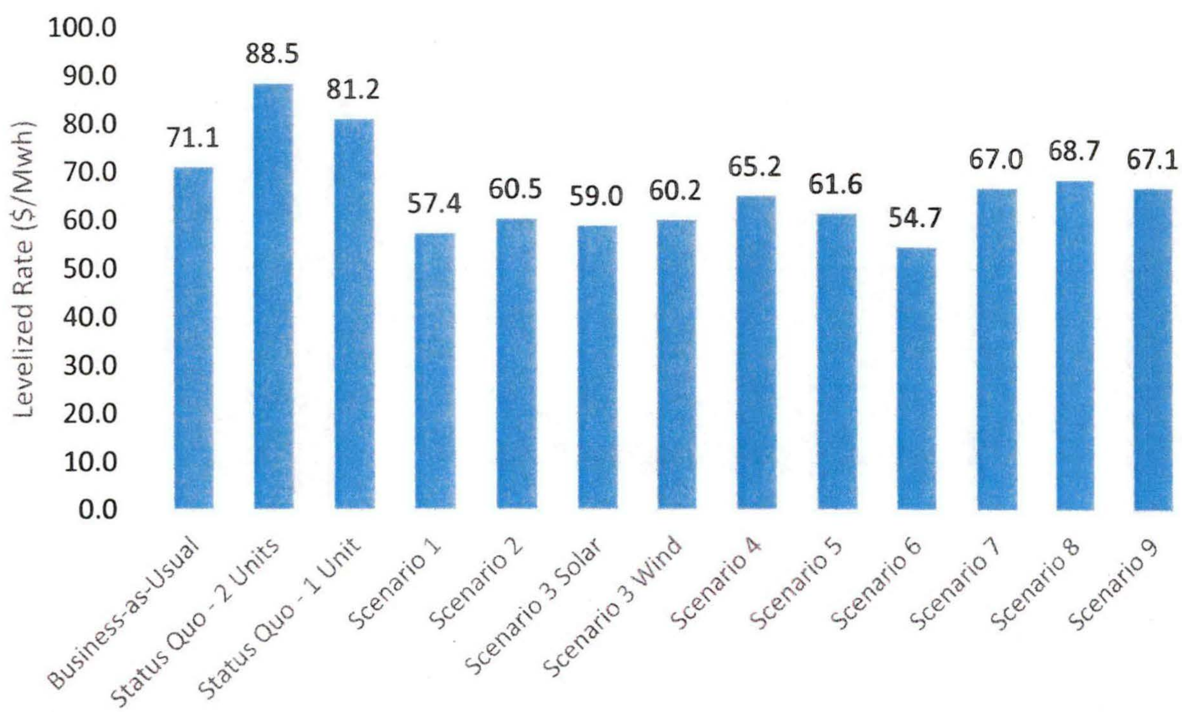


Figure 7-2: LRFF Scenario Comparison: 10-yr Levelized Rate



Upon analyzing the results of the LRFF scenarios, notable observations include:

- The status quo scenarios whereby Station 2 remains operational produce the highest annual revenue requirement during the initial forecast period, only to be surpassed by the nuclear scenarios in the outer years due to the significant capital investment of a nuclear resource.

- The minimum net income constraint was the limiting factor in the status quo scenario with two units due to the considerable cash benefits associated with the full depreciation expense of Station 2.

- The minimum cash balance constraint was the controlling factor for determining revenues for virtually all other scenarios, with the exception for the nuclear scenarios which invoked the minimum DSC of 1.25 due to the relatively sizeable debt service associated with a nuclear option.

- The 10-yr levelized rate summary comparison provides snapshot of the various scenarios and provides an indication of the relative costs of the scenarios over that time period. As illustrated in Figure 7-2, all "non-coal" scenarios provide economic benefits as compared to the "coal scenarios".

It should be noted that this LRFF scenario analysis is meant to provide a means to evaluate and compare the economic impact of the various power supply options from an income and cash flow statement perspective only. Further detailed evaluation from an accounting standpoint is needed to fully determine the impacts and financial implications for scenarios involving the retirements of one or both units at HGS.

8.0 Summary Results for Generation Portfolios

The combination of the economic hourly dispatch results and the fixed carrying cost, fixed O&M expenses, and other fixed purchased power related expenses produces the total cost for each generation resource alternative. The annual projected costs are discounted back to 2018 dollars for a net present value comparison of all scenarios, including the BAU scenario. This process allows HMP&L to compare the most economically feasible alternatives and determine the potential benefits of continuing to operate and maintain the coal plants relative to a plethora of other generation and market alternatives.

Table 8 – 1 compares the net present value and the levelized rate over the IRP study period of all the generation scenarios, starting with the BAU scenario. Table 8 – 1 represents the combination of the key sensitivities under the base capacity price projections and the three different fuel price sensitivities (i.e. base, high, and political).

Table 8-1: Total NPV Power Cost and Levelized Rate for IRP Study (2019 – 2038)

Base Capacity Price	Base Fuel		High Fuel		Political Fuel	
Scenario	NPV ($Millions)	Rate ($/MWh)	NPV ($Millions)	Rate ($/MWh)	NPV ($Millions)	Rate ($/MWh)
1. Business As Usal (BAU)	$453.6	$52.46	$564.8	$65.33	$555.0	$64.20
2. HMP&L - Both HGS Units	$622.8	$72.04	$729.5	$84.39	$617.9	$71.47
3. HMP&L - One HGS Unit	$572.6	$66.24	$689.5	$79.76	$678.8	$78.52
4. Scenario 1 - Block PPAs	$356.1	$41.19	$503.6	$58.25	$592.1	$68.49
5. Scenario 2 - RICE / LM2500, Block PPA	$381.2	$44.09	$523.6	$60.57	$607.9	$70.32
6. Scenario 3 - LM2500, Block PPA, Wind	$378.7	$43.80	$506.9	$58.63	$580.8	$67.18
7. Scenario 3 - LM2500, Block PPA, Solar	$369.3	$42.72	$510.1	$59.01	$593.2	$68.62
8. Scenario 4 - LM6000, Wind PPA	$424.9	$49.15	$503.5	$58.24	$558.2	$64.56
9. Scenario 5 - RICE, Wind PPA	$388.0	$44.88	$459.9	$53.19	$510.1	$59.01
10. Scenario 6 - MISO Market	$333.6	$38.59	$440.2	$50.92	$515.7	$59.65
11. Scenario 7 - Modular Nuclear	$609.9	$70.55	$653.6	$75.60	$689.9	$79.80
12. Scenario 8 - Modular Nuclear, Wind	$623.4	$72.11	$649.8	$75.16	$673.5	$77.91
13. Scenario 9 - Modular Nuclear, Block PPA	$612.1	$70.80	$655.9	$75.87	$695.0	$80.39

While specific sensitivities will be discussed in Section 9.0, it is worth discussing a few key observations from the results shown in Table 8-1. First, the Base fuel price results underscore the benefits of the current market environment and expectations for the continuation of low gas prices and low capacity pricing. The benefits of the BAU scenario are obvious compared to any scenario where HMP&L continues to operate the HGS facility, either one or two units, but it is also apparent that HMP&L should consider transitioning away from the BAU scenario to another combination of alternative power supply resources to serve its future load.

Furthermore, while the BAU scenario provides some additional benefits in the high and political fuel scenarios, there are still numerous alternative resource scenarios that produce equivalent or greater benefits. As a reminder, some conservative assumptions were made with respect to the BAU scenario, including no capital upgrade or maintenance expenses beyond 2023 (this includes major and regular maintenance expenses).

9.0 Sensitivity Scenario Results

Table 8 – 1 demonstrated the expected total power cost for all the IRP resource alternatives under the base capacity price assumption as well as the fuel price sensitivities. This section of the report focuses on the differences between the resource scenarios under different capacity and fuel price sensitivities.

As mentioned earlier, the key modeling sensitivities are two capacity pricing scenarios as well as three fuel pricing scenarios. The purpose of evaluating the same resource alternatives under different sensitivities is to understand the potential volatility associated with a particular combination of resources. Understanding the potential volatility of a resource portfolio allows electric utilities to better manage potential risks that impact the utilities' goals and strategic objectives. This is commonly observed from a retail rate perspective, that is, what would the impact be on the utility's retail rates and is that within a certain range of acceptable risk to the utility.

The three tables below compare the total power cost of the resource alternatives under different capacity pricing assumptions and different fuel pricing assumptions so that HMP&L understands whether or not continuing to own and operate the HGS facility, under any of the three offtake structures, provides benefits relative to other potential resource combinations.

Table 9-1: Base Fuel Price Comparison (NPV Cost and Levelized Rate 2019 – 2038)

Base Fuel Price	Base Capacity		High Capacity	
Scenario	NPV ($Millions)	Rate ($/MWh)	NPV ($Millions)	Rate ($/MWh)
1. Business As Usal (BAU)	$453.6	$52.46	$453.6	$52.46
2. HMP&L - Both HGS Units	$622.8	$72.04	$555.8	$64.29
3. HMP&L - One HGS Unit	$572.6	$66.24	$558.8	$64.63
4. Scenario 1 - Block PPAs	$356.1	$41.19	$395.0	$45.69
5. Scenario 2 - RICE / LM2500, Block PPA	$381.2	$44.09	$405.2	$46.87
6. Scenario 3 - LM2500, Block PPA, Wind	$378.7	$43.80	$407.4	$47.13
7. Scenario 3 - LM2500, Block PPA, Solar	$369.3	$42.72	$399.5	$46.22
8. Scenario 4 - LM6000, Wind PPA	$424.9	$49.15	$438.5	$50.72
9. Scenario 5 - RICE, Wind PPA	$388.0	$44.88	$409.3	$47.34
10. Scenario 6 - MISO Market	$333.6	$38.59	$372.5	$43.08
11. Scenario 7 - Modular Nuclear	$609.9	$70.55	$633.0	$73.21
12. Scenario 8 - Modular Nuclear, Wind	$623.4	$72.11	$644.2	$74.52
13. Scenario 9 - Modular Nuclear, Block PPA	$612.1	$70.80	$635.1	$73.46

Table 9-2: High Fuel Price Comparison (NPV Cost and Levelized Rate 2019 – 2038)

High Fuel Price	Base Capacity		High Capacity	
Scenario	NPV ($Millions)	Rate ($/MWh)	NPV ($Millions)	Rate ($/MWh)
1. Business As Usal (BAU)	$564.8	$65.33	$564.8	$65.33
2. HMP&L - Both HGS Units	$729.5	$84.39	$662.6	$76.64
3. HMP&L - One HGS Unit	$689.5	$79.76	$675.7	$78.16
4. Scenario 1 - Block PPAs	$503.6	$58.25	$542.4	$62.74
5. Scenario 2 - RICE / LM2500, Block PPA	$523.6	$60.57	$547.7	$63.35
6. Scenario 3 - LM2500, Block PPA, Wind	$506.9	$58.63	$535.6	$61.95
7. Scenario 3 - LM2500, Block PPA, Solar	$510.1	$59.01	$540.4	$62.51
8. Scenario 4 - LM6000, Wind PPA	$503.5	$58.24	$517.1	$59.82
9. Scenario 5 - RICE, Wind PPA	$459.9	$53.19	$481.1	$55.65
10. Scenario 6 - MISO Market	$440.2	$50.92	$479.1	$55.42
11. Scenario 7 - Modular Nuclear	$653.6	$75.60	$676.6	$78.27
12. Scenario 8 - Modular Nuclear, Wind	$649.8	$75.16	$670.6	$77.56
13. Scenario 9 - Modular Nuclear, Block PPA	$655.9	$75.87	$678.9	$78.53

Table 9-3: Political Fuel Price Comparison (NPV Cost and Levelized Rate 2019 – 2038)

Political Fuel Price	Base Capacity		High Capacity	
Scenario	NPV ($Millions)	Rate ($/MWh)	NPV ($Millions)	Rate ($/MWh)
1. Business As Usal (BAU)	$555.0	$64.20	$555.0	$64.20
2. HMP&L - Both HGS Units	$617.9	$71.47	$550.9	$63.72
3. HMP&L - One HGS Unit	$678.8	$78.52	$665.0	$76.91
4. Scenario 1 - Block PPAs	$592.1	$68.49	$631.0	$72.99
5. Scenario 2 - RICE / LM2500, Block PPA	$607.9	$70.32	$632.0	$73.10
6. Scenario 3 - LM2500, Block PPA, Wind	$580.8	$67.18	$609.5	$70.51
7. Scenario 3 - LM2500, Block PPA, Solar	$593.2	$68.62	$623.5	$72.11
8. Scenario 4 - LM6000, Wind PPA	$558.2	$64.56	$571.8	$66.14
9. Scenario 5 - RICE, Wind PPA	$510.1	$59.01	$531.4	$61.47
10. Scenario 6 - MISO Market	$515.7	$59.65	$554.6	$64.15
11. Scenario 7 - Modular Nuclear	$689.9	$79.80	$712.9	$82.46
12. Scenario 8 - Modular Nuclear, Wind	$673.5	$77.91	$694.3	$80.31
13. Scenario 9 - Modular Nuclear, Block PPA	$695.0	$80.39	$718.0	$83.05

There is a lot of information shown in the previous three tables but the key conclusion after reviewing HMP&L's total power cost under all the resource alternative portfolios and comparing that to continued ownership in the HGS facility is that HMP&L should start focusing on transitioning away from the HGS facility and focusing on a new combination of power supply resources. In all of these scenarios, there are multiple alternative resource portfolios that provide equivalent or greater benefits that continuing to own the HGS facility.

Thinking specifically of volatility for each resource portfolio, the next two figures compare the range of potential power supply cost under the Base and High capacity pricing sensitivities across the three fuel price sensitivities. This is a helpful illustration to demonstrate volatility of specific resource portfolios and yet, reinforce the conclusion that HMP&L has opportunities to transition to another set of power supply resources and still provide tremendous benefits to its retail customers.

Figure 9-1: Base Capacity Price Power Cost Volatility (Levelized Rate 2019 – 2038)

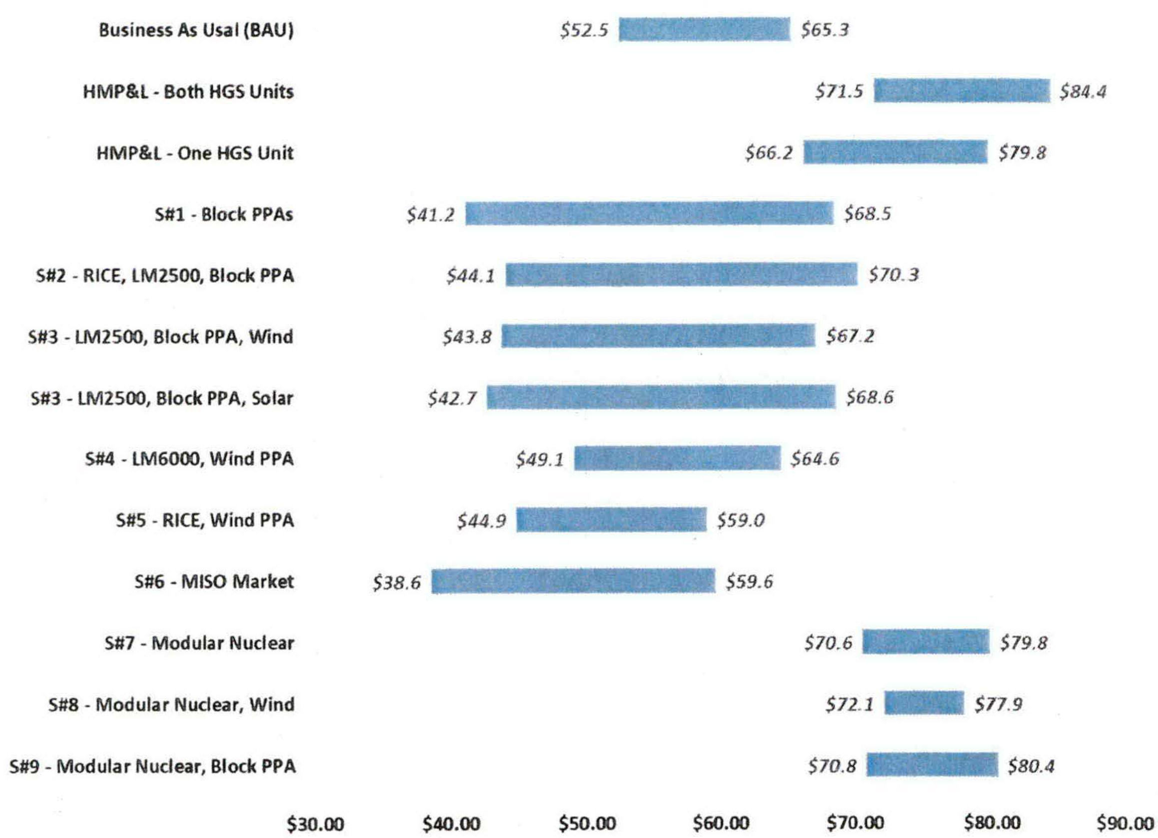
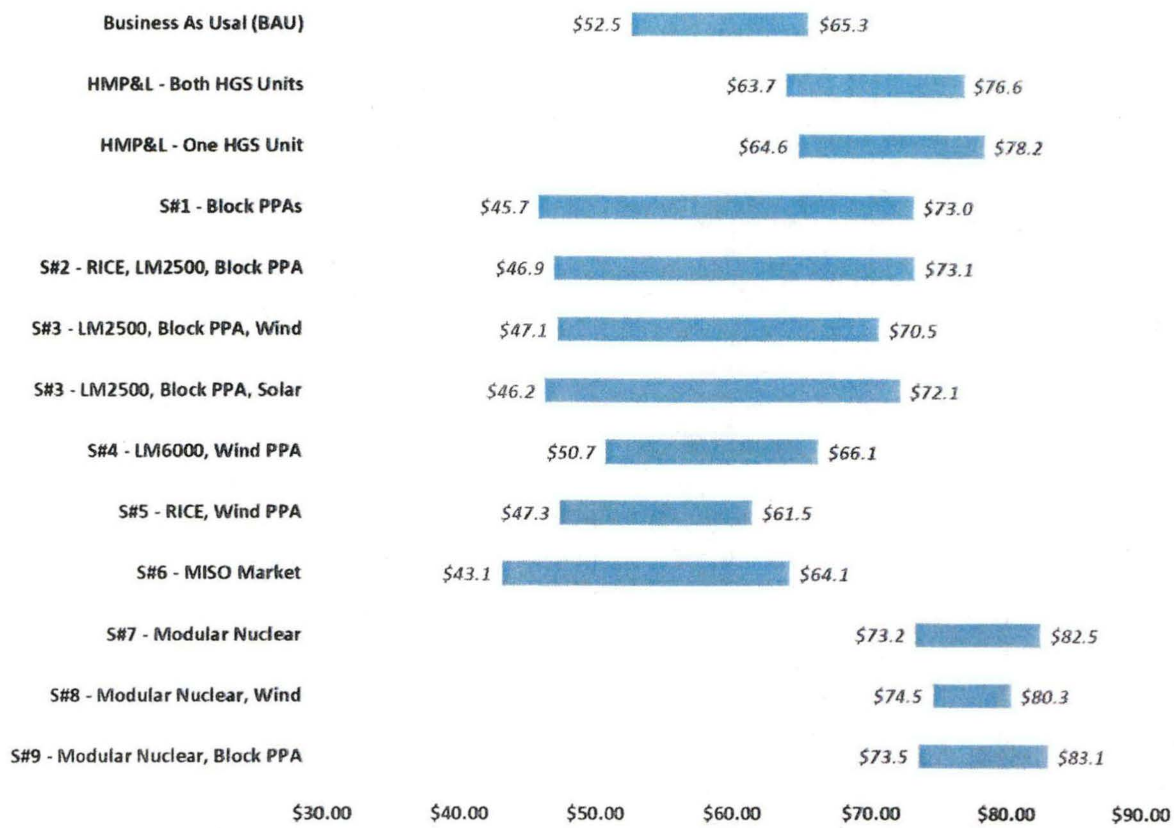


Figure 9-2: High Capacity Price Power Cost Volatility (Levelized Rate 2019 – 2038)



As expected, the BAU volatility is constant in the base and high capacity price sensitivities because HMP&L has no excess capacity nor any capacity deficiencies in the BAU case. Also, the exclusive ownership of the HGS facility produces some incremental benefits under the high capacity price scenario because HMP&L would have some excess capacity to sell back to the market. However, the vast majority of the alternative resource portfolios only have modest exposure to higher capacity prices and generally provide HMP&L with a reasonable level of insulation from higher power cost (e.g. all scenarios only increase $2 - $5/MWh under the high capacity price sensitivity).

Something to note is the minimal volatility with all three of the modular nuclear alternatives. This is certainly not surprising given nuclear generation's insulation from changes in gas prices and the expectation is that nuclear fuel pricing would be completely independent of natural gas prices. There is no historical correlation between those two fuels, and while this IRP evaluation does not recommend that HMP&L pursue a nuclear resource, it is worth mentioning that procuring and maintaining non-gas resources will be an important risk mitigation strategy against future gas price uncertainty.

The conclusion from evaluating the resource volatility is that there is greater volatility with the "non-coal" portfolios, however, several of these "non-coal" portfolios have approximately the same or lower power cost than the BAU scenario even in the "worst case" combinations of extremely high fuel and capacity prices. In addition, there are steps that can be taken to manage potential volatility for these alternative resource portfolios, based on HMP&L's goals, that are not taken into account in this economic feasibility study.

10.0 Conclusions/Recommendations

The IRP study's main purpose is to inform HMP&L on the value and benefits of continuing to own and operate the HGS facility versus transitioning to, and investing in, a new power supply resource portfolio. This IRP evaluation is not designed to specifically recommend an alternative power supply portfolio but simply conclude if there are viable alternatives as opposed to continuing to own and operate HGS.

As HMP&L has appreciated for many years, the existing HGS facility has provided tremendous benefits to HMP&L's retail customers for over 40 years. As the HGS facility reaches the end of its originally anticipated commercial operation life, HMP&L is faced with a similar opportunity as the management team of HMP&L faced almost 50 years ago – what is the best choice for HMP&L's future and where should the utility invest for its future? As HMP&L is aware, the electric utility industry has changed tremendously over the past 50 years.

In order to help answer that question, the IRP evaluation identified numerous, viable commercially available generation technologies, coupled with the benefits of the MISO market and the ability to procure standard PPA blocks from independent third-party suppliers. While the economics of the various resource scenarios has been shown in previous sections of this report, the following three figures provide a simple visual representation of HMP&L's total power cost over the IRP's 20 year study period. Each chart includes a comparison of the base and high capacity pricing scenarios under each of the three fuel pricing sensitivities. Emphasis has been placed on the expected power cost from the BAU scenario for ease of comparing alternative power supply portfolios.

Figure 10-1: HMP&L Power Cost with Base Fuel Prices (NPV 2019 – 2038)

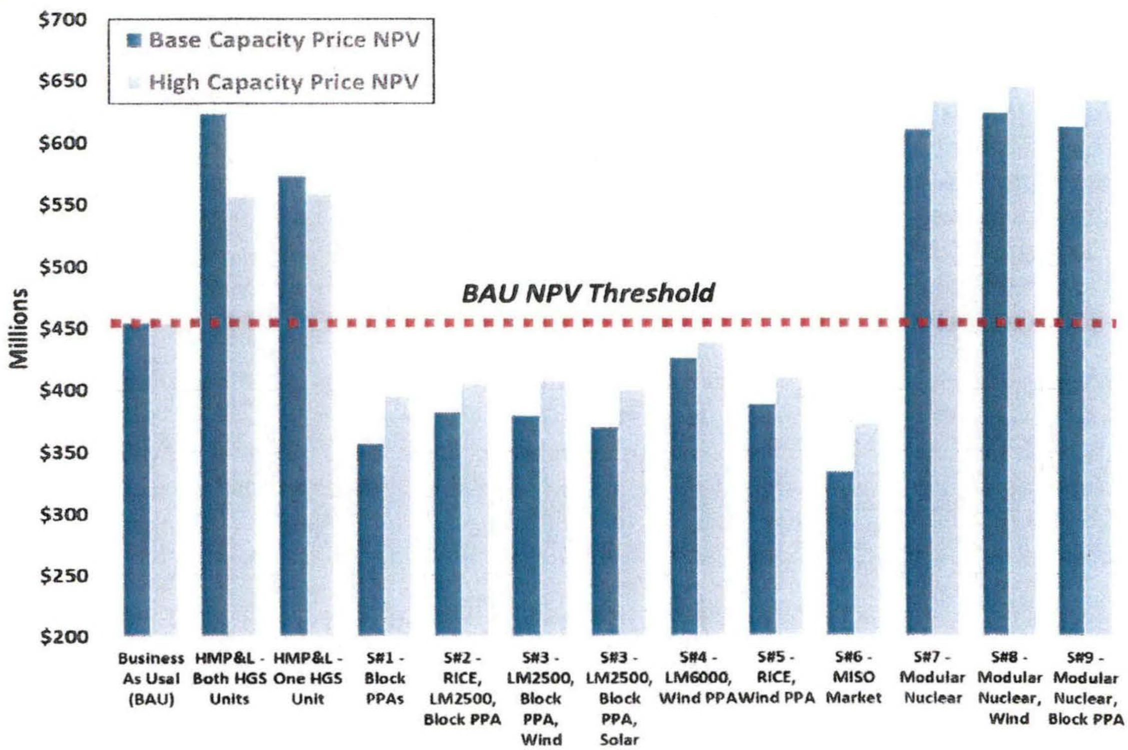


Figure 10-2: HMP&L Power Cost with High Fuel Prices (NPV 2019 – 2038)

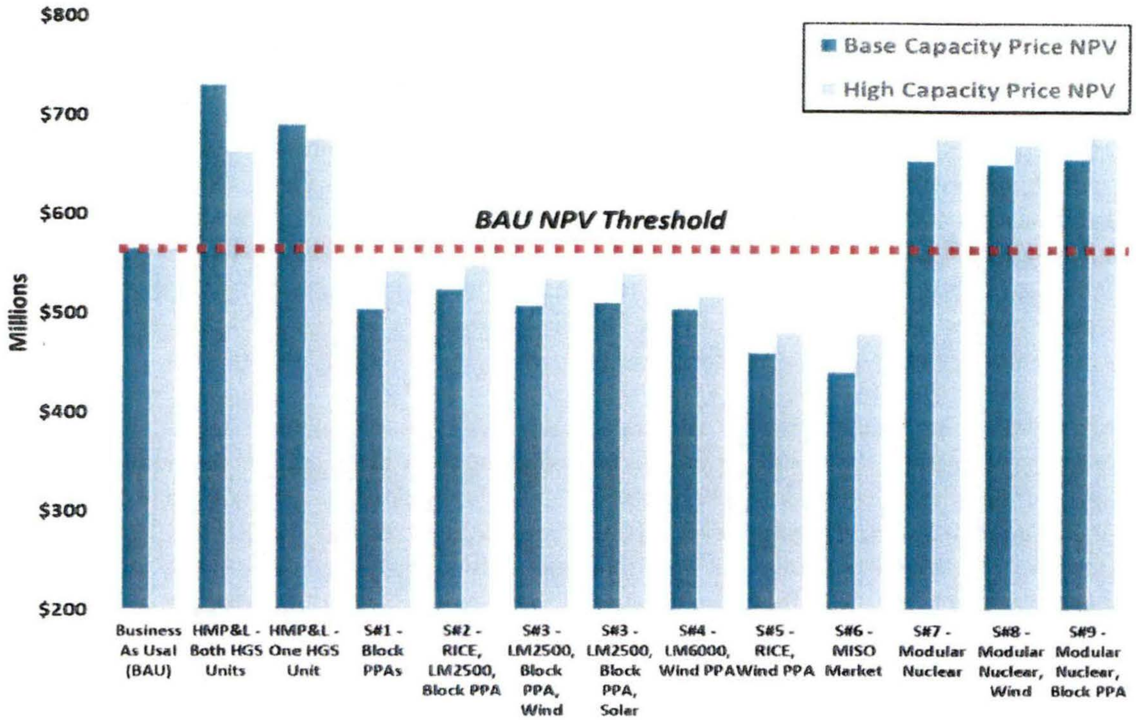
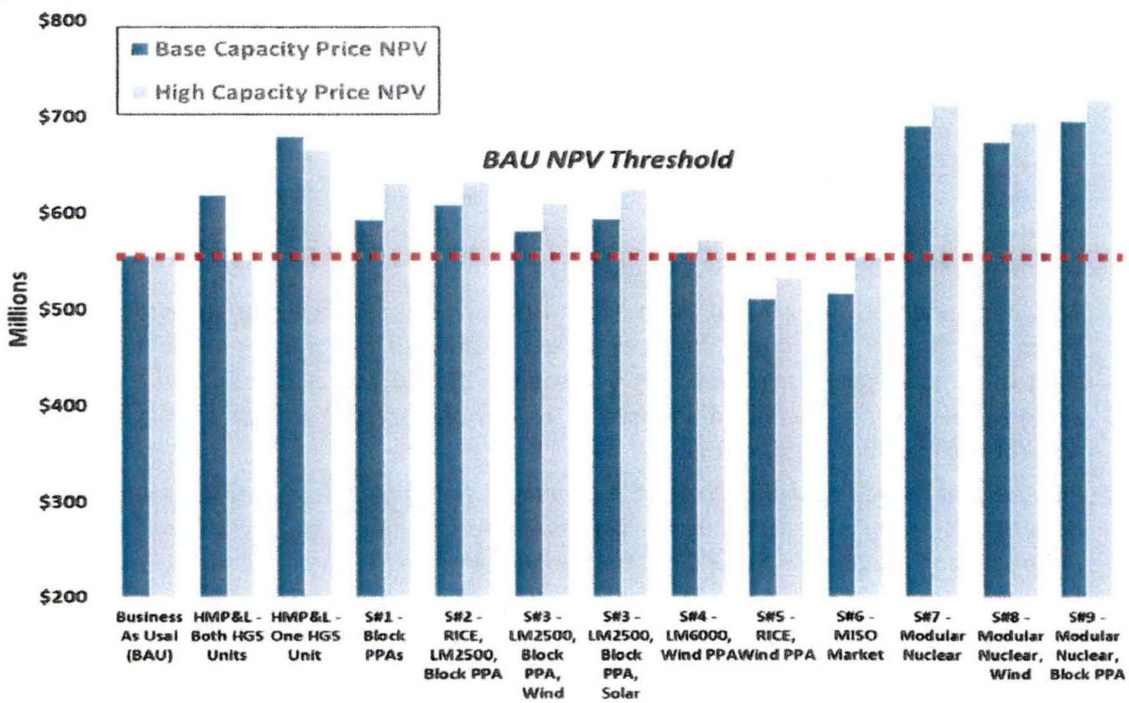


Figure 10-3: HMP&L Power Cost with Political Fuel Prices (NPV 2019 – 2038)



For the base and high fuel price sensitivities (Figures 10-1 and 10-2, respectively), all alternative resource scenarios, excluding the modular nuclear option, have a lower projected cost than continuing the BAU scenario. Under the political fuel price sensitivity, three of the alternative resource scenarios (resource scenarios 4, 5, and 6) have equivalent or lower power cost than the BAU scenario and this is based upon the worst combination of gas and capacity prices for HMP&L. For this specific scenario, some of the other non-coal alternatives that have a higher power cost than the BAU (specifically resource scenarios 1, 2, and 3) are using a conservative, simplifying assumption for the 7 x 24 and 5 x 16 energy block PPAs that results in "higher" power cost. The simplifying assumption is that power suppliers have already priced in the political fuel prices into their energy block prices – meaning that today (at the time of the study) the energy block pricing is based on the political gas prices and not the current, low gas price environment that is projected for the immediate future. So, the first 5 and 10 year energy blocks are priced much higher in the study relative to what HMP&L could procure them for in today's market.

Because the IRP evaluation has multiple resource scenarios that result in a lower overall power cost than the BAU scenario in every sensitivity of the IRP, coupled with the fact that a key assumption for the BAU scenario (and the other two scenarios where HMP&L had continued HGS ownership) did not include any normal or major capital investments beyond 2023, the conclusion of this study is that HMP&L should divest itself of the HGS asset. This is a significant and monumental point for HMP&L and represents something of a "pivot" for HMP&L's future because of the reliance on the HGS facility for over 40 years.

A summary of the IRP report's conclusion and next steps are as follows:

1. For the numerous reasons stated earlier in the IRP report, GDS recommends that HMP&L should take the necessary steps to retire the HGS facility and engage in discussions with BREC on achieving a reasonable timetable and schedule to properly decommission and retire the facility. Inherent in this recommendation is that HMP&L will not spend any capital for maintenance upgrades and environmental requirements at HGS, above and beyond what is required to keep the plant available and operating until retirement can be achieved;
2. HMP&L should evaluate its relationship with BREC as it pertains to the MISO market and related market interactions and consider transitioning to operating as a fully independent Market Participant (i.e. responsible for all MISO interactions and decisions). The analysis should consider meeting MISO market obligations, cost of ancillary and transmission arrangements, and benefits of direct interactions with the MISO market;
3. GDS recommends that HMP&L identify short-term power supply arrangements that will economically serve as a "bridge" for an eventual transition to other power supply resources. The short-term and long-term power supply resources should complement HMP&L's objectives, strategic goals, and risk management policies. Ideally, this exercise would be achieved in tandem with recommendation number 2; and,
4. Propose that HMP&L set aside time and resources in the coming fiscal year to evaluate potential longer-term power supply resources, develop a procurement strategy for acquiring related resources, and develop a schedule for implementing the long-term power supply resource plan.

These recommendations and resulting actions will establish the best course of HMP&L for the immediate future. This concludes the IRP study process, evaluation, and recommendations for this report.

Berry, Bob

From: Chris Heimgartner [redacted]
Sent: Tuesday, February 27, 2018 10:56 AM
To: Berry, Bob [redacted]
Subject: Station 2 Operations

Dear Bob,

I want to thank you and your team for taking time to meet with us on February 12. I think we had a lively and open discussion of some of the issues between us.

During our discussion on how to operate the plant in an economic dispatch mode, we had proposed a mechanism for both parties to share both the costs to operate the units, and the revenue from the units. You had indicated a willingness to talk about that if we included a definite path for Big Rivers to exit the Power Sales Contract.

After much internal deliberation, I have concluded that we should continue to work together to craft an agreement on how to allocate the costs and revenues in an economic dispatch operation. I do not, however, think that negotiating an exit strategy for Big Rivers from the Power Sales Contract is in our citizens' best interest.

I remain hopeful and available to discuss economic dispatch operations at Station 2 with you. We do need to come to an arrangement on cost allocation.

In another matter, I will be responding to your February 16 letter under separate cover.

Thanks,

Chris Heimgartner

Exhibit Berry-4

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

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-__________**

DIRECT TESTIMONY

OF

METIN CELEBI

PRINCIPAL
OF
THE BRATTLE GROUP, INC.

ON BEHALF OF

BIG RIVERS ELECTRIC CORPORATION

FILED: **May 1, 2018**

DIRECT TESTIMONY

OF

METIN CELEBI

<u>Table of Contents</u>

DIRECT TESTIMONY

OF

METIN CELEBI

I. <u>INTRODUCTION AND QUALIFICATIONS</u>

Q. Please state your name, business address, and position.

A. My name is Metin Celebi. I am a principal with The Brattle Group, Inc. ("The Brattle Group"). My business address is One Beacon Street, Suite 2600, Boston, MA 02108.

Q. On whose behalf are your testifying?

A. I am testifying on behalf of Big Rivers Electric Corporation ("Big Rivers").

Q. Briefly describe your business and educational background.

A. For more than fifteen years, I have been employed as a consultant in the electric power industry. My expertise includes assessing the economic viability of coal plants, forecasting of wholesale energy and capacity prices, resource planning, and analysis of environmental and climate policy. I have provided expert testimony in cases before the Federal Energy Regulatory Commission (FERC), Public Service Commission of Wisconsin, Pennsylvania Public Utilities Commission, Public Utilities Commission of Texas, and Superior Court of the State of Arizona on topics ranging from a long-term power contract dispute in California to the impact of coal plant retirements on wholesale energy prices in MISO, LMP spikes in PJM, allocation of certain ancillary services costs among market participants in ERCOT, and wholesale power prices in Arizona. I have provided services as an expert consultant or expert witness to the following public utilities: Ameren Missouri, Basin Electric Power Cooperative, Empire District Electric Company, Great River Energy, Kansas City Power & Light, Owensboro Municipal

Utilities, PacifiCorp Energy, Pennsylvania Electric Company, Salt River Electric, Southern California Edison, and Wisconsin Public Service Corporation.

I hold a Ph.D. in Economics from Boston College with a dissertation on transmission investment and power system modeling, a Masters in Economics from Bilkent University in Ankara, Turkey, and a Bachelor of Science in Industrial Engineering from Middle East Technical University (METU) in Ankara, Turkey. A copy of my résumé is attached as Exhibit Celebi-1.

Q. Please describe the nature of services performed by the Brattle Group.

A. The Brattle Group provides consulting services and expert testimony on economic, financial, regulatory, and strategic issues to corporations, law firms, and public agencies worldwide, including public utilities. We provide expert testimony on economic evaluation, antitrust and competitive analyses, financial risk, regulatory economics, and environmental matters. The industry practice areas in which we specialize are electric power, natural gas, petroleum, financial institutions, pharmaceuticals, healthcare, telecommunications and media, transportation, and water.

Our largest industry practice area is in electric power. In our electric power work, we assist ISOs, electric utilities, deregulated power producers, customers, regulators, and policy makers with planning, analysis, regulatory, and litigation support. Our team offers a range of operational and financial tools and models for simulating, forecasting, and evaluating market structure as well as economic or financial analyses for an individual company or sector. Our experience spans electricity markets worldwide and reflects our depth in the global energy sector, and we frequently appear as experts before regulatory agencies, courts, or arbitration panels.

The Brattle Group was founded in 1990 in Cambridge, MA. Since that time, The Brattle Group has grown to a staff of more than 300 with more than 80 consultants in the energy and utilities practice areas. We have expanded geographically and work out of offices in Boston, Washington DC, San Francisco, New York City, Toronto, London, Rome, Madrid, and Sydney.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe and support the economic analysis that I performed on behalf of Big Rivers to determine whether Unit 1 and Unit 2 at the Henderson Station 2 Generation Plant ("Station Two"), or either of them, is capable of "normal, continuous, reliable operation for the economically competitive production of electricity".[1] The contract among the City of Henderson, City of Henderson Utility Commission and Big Rivers Electric Corporation which governs the operation of Station Two provides that: "[t]he terms of all the Contracts except the Joint Facilities Agreement shall be extended for the operating life of Station Two, the operating life of which shall be considered to continue for so long as Unit 1 and Unit 2, or either of them, is operated, or is capable of normal, continuous, reliable operation for the economically competitive production of electricity, temporary outages excepted."[2]

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1 My analysis of the Station Two plant is limited to its economic viability (i.e., the plant's capability to provide "economically competitive production of electricity"), and I do not provide an opinion on engineering aspects of plant operations. Therefore, in my testimony, I assume that Station Two is capable of normal, continuous, and reliable operation.

2 "Amendments to Contracts Among City of Henderson, Kentucky, City of Henderson Utility Commission and Big Rivers Electric Corporation", dated July 15, 1998, page 2.

Q. Are you sponsoring any exhibits?

A. Yes. I have prepared the following exhibits to support my testimony:

Exhibit Celebi-1 – Résumé of Metin Celebi

Exhibit Celebi-2 – Report on Economic Viability of Station Two

III. SUMMARY OF CONCLUSIONS

Q. Please provide a summary of your conclusions.

A. In each and every year of the study period, from 2019 through 2035, and under every scenario that I evaluated, Station Two's projected annual costs will exceed its potential revenues. Additionally, during each year that either or both of the Station Two units continue to operate, the cumulative negative margins will worsen. Every year that retirement of Station Two is delayed will result in a greater financial loss. Based on the analysis that I performed, neither Unit 1 nor Unit 2 individually, nor both of them together, are capable of normal, continuous, reliable operation for the economically competitive production of electricity.

IV. BACKGROUND ON STATION TWO

Q. Please describe the location and key characteristics of Station Two.

A. Station Two is a coal-fired power plant with 312 MW generation capacity, located near Sebree, Kentucky. Station Two consists of two generating units, Unit 1 and Unit 2, with 153 MW and 159 MW of generating capacity, respectively.

Q. Who is the owner and the operator of Station Two?

A. Station Two is wholly owned by Henderson Municipal Power & Light ("HMPL"), and operated by Big Rivers. Big Rivers has contractual rights to a portion of the energy and capacity from Station Two under a purchase and sale agreement that was executed in 1970 (and amended multiple times).[3]

Q. Does Station Two operate in an organized wholesale market?

A. Yes. I understand Big Rivers offers the energy and capacity from Station Two into the wholesale power markets operated by Midcontinent Independent System Operator ("MISO").[4]

Q. Please describe the sources of revenues for Station Two in the MISO wholesale power markets.

A. MISO's wholesale power markets include a day-ahead energy market, a real-time energy market, and an annual planning resource auction ("PRA") capacity market for meeting resource adequacy obligations. Therefore, energy and capacity offered from Station Two would receive revenues in these markets when MISO selects Station Two to provide such services. I understand that the Station Two revenues from MISO's PRA capacity market are used by Big Rivers to offset the resource adequacy requirements of load served by HMPL and a portion of load served by Big Rivers.

Q. Please describe the historical annual energy output and operations of Station Two.

A. Over the last four years (2014 through 2017), annual net generation from Station Two decreased from about 2.3 million MWh in 2014 to about 1.2 million MWh in 2017. Expressed in annual capacity factor (ratio of annual generation to total maximum

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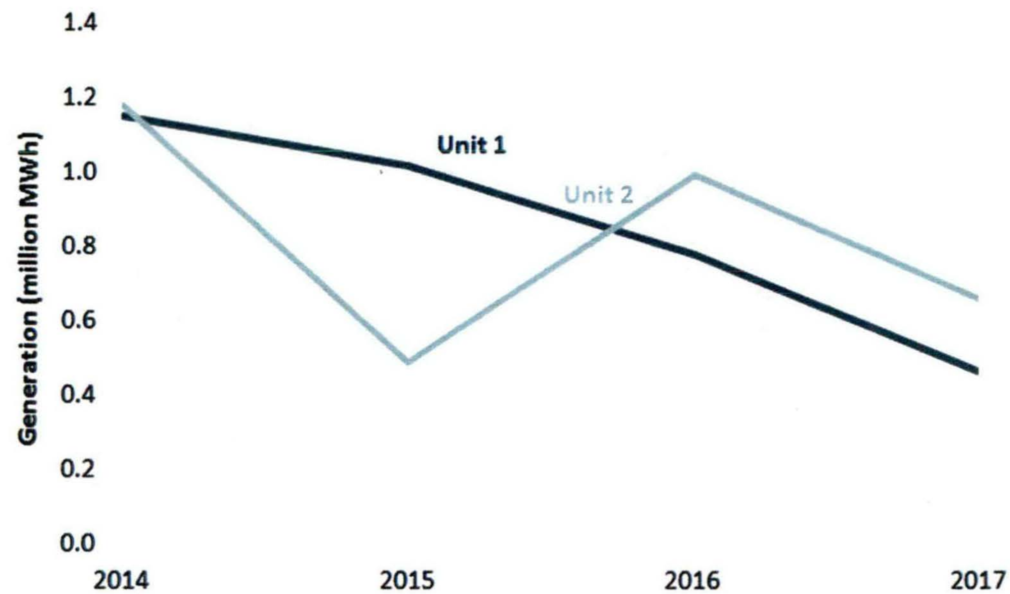
[3] *See* Power Sales Contract.

[4] *See* Direct Testimony of Robert W. Berry.

generation from operating at capacity in all hours), Station Two operated at an 88% capacity factor in 2014 and 45% capacity factor in 2017.

Figure 1: Station Two Historical Annual Generation



Source: Data from Big Rivers.

During much of 2017, I understand that Station Two units were operated in the MISO energy market as must-run (i.e., the combined output was at least 235 MW from the two units) until approximately the end of July 2017. Beginning late July 2017, the must-run operations were replaced with the operating strategy of offering one unit in the MISO energy market based on economic commitment (with minimum generation at 115 MW for Unit 1 and 120 MW for Unit 2). The second unit began being offered on an economic commitment basis in early October 2017. Under the economic commitment strategy after early October 2017, the minimum generation of the units was reduced to about 56 MW per unit if the unit is selected to generate power.

Q. How much revenue did Station Two earn in the MISO wholesale energy and capacity markets in 2017?

A. The market revenues in 2017 from energy generated by Station Two were about [redacted], and capacity market revenues of Station Two were about [redacted].

Q. How much operating cost did Station Two incur in 2017?

A. In 2017, total variable costs (fuel, variable operating and maintenance ("O&M"), and emissions allowances) for Station Two were about [redacted]. The fixed O&M and capital costs during the same year were about [redacted] and [redacted], respectively. Expressed in costs per MWh of generation output, Station Two's operating costs in 2017 were about [redacted].

Figure 2: Station Two Operating Costs in 2017

	Unit 1	Unit 2	Station 2
$ Millions	[redacted]	[redacted]	[redacted]
Total Variable Costs	[redacted]	[redacted]	[redacted]
Fixed O&M Costs	[redacted]	[redacted]	[redacted]
Capital Costs	[redacted]	[redacted]	[redacted]
Total Operating Costs	[redacted]	[redacted]	[redacted]
$/MWh	[redacted]	[redacted]	[redacted]
Total Variable Costs	[redacted]	[redacted]	[redacted]
Fixed O&M Costs	[redacted]	[redacted]	[redacted]
Capital Costs	[redacted]	[redacted]	[redacted]
Total Operating Costs	[redacted]	[redacted]	[redacted]

Source: Data from Big Rivers.

Q. Please explain how Station Two's operating costs compared to MISO market revenues in 2017.

A. In 2017, Station Two's operating costs (total of [redacted]) exceeded its energy and capacity revenues in the MISO market (about [redacted]) by about [redacted]. In other words, Station Two incurred about [redacted] of financial losses in 2017. On a per MWh of generation output, Station Two's energy margin (energy revenues minus variable costs) was negative [redacted] and its gross margin (revenues from energy and capacity markets minus all operating costs) was negative [redacted].

Figure 3: Station Two Costs and Revenues in 2017

	Unit 1	Unit 2	Station 2
$ Millions	[redacted]		
Total Variable Costs	[redacted]		
DA Energy Revenues	[redacted]		
RT Energy Revenues	[redacted]		
Energy Margins	[redacted]		
Fixed O&M and CapEx	[redacted]		
Capacity Revenues	[redacted]		
Gross Margin	[redacted]		
$/MWh	[redacted]		
Total Variable Costs	[redacted]		
DA Energy Revenues	[redacted]		
RT Energy Revenues	[redacted]		
Energy Margins	[redacted]		
Fixed O&M and CapEx	[redacted]		
Capacity Revenues	[redacted]		
Gross Margin	[redacted]		

Source: Data from Big Rivers.
Note: Costs and revenues reported in $/MWh use actual generation.

V. ANALYTICAL APPROACH AND KEY ASSUMPTIONS

A. Overview

Q. Please describe the analysis Big Rivers requested you to perform.

A. As noted above, I was asked to assess whether Unit 1 and Unit 2 of Station Two, or either of them, is operated, or is capable of "normal, continuous, reliable operation for the economically competitive production of electricity"[5].

Q. How did you assess whether Station Two is capable of "economically competitive production of electricity"?

A. I made this assessment by comparing the projected annual gross margins for Station Two units in the MISO wholesale power markets under several market outlooks. The annual gross margins are the difference between avoidable costs of operating Station Two and the projected revenues that Station Two would receive from the MISO wholesale power markets.

The projected avoidable[6] costs include fuel, O&M, and capital expenditures that would be incurred unless Station Two is retired. The projected revenues from the MISO wholesale power markets include revenues from MISO day-ahead[7] energy markets and MISO capacity market.

Under this framework, if the future gross margins for Station Two are negative (i.e., the avoidable costs of operating Station Two are greater than the future revenues that Station Two would receive in the MISO wholesale markets), then Station Two would not be capable of "economically competitive production of electricity". I made these assessments of future gross margins both on an annual basis and on a present value basis.

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5 My analysis of the Station Two plant is limited to its economic viability (i.e., the plant's capability to provide "economically competitive production of electricity"), and I do not provide an opinion on engineering aspects of plant operations. Therefore, in my testimony, I assume that Station Two is capable of normal, continuous, and reliable operation.

6 Avoidable costs exclude costs that would have to be incurred regardless of whether the plant continues to operate, such as costs of upgrading or closing ash ponds.

7 I focused my analysis of projected energy revenues in the day-ahead energy market (instead of the real-time energy market) since most of the generation output from coal plants are typically scheduled and financially committed in the day-ahead market. The real-time market is a balancing market for changes in load, outages, and system conditions.

Based on the projected annual gross margins for Station Two, I also compared the present value of future gross margins at different years of retiring one or both of the units at Station Two. For that assessment, I took into account the changes in present value of incurring the plant decommissioning costs at different years of retirement.

Q. Please describe why the MISO power market was used as the basis for the analysis?

A. I understand that Station Two generation plant has been operating in the MISO power market since 2010[8], and the power output of the plant has been sold in the wholesale power markets operated by MISO.[9] I also understand that there is currently no plan to operate Station Two in a market other than in the MISO wholesale markets.[10] Since Station Two is currently operating in the MISO market and is expected to continue in the future, the MISO market is the appropriate context for evaluation of Station Two's economic viability, or its ability to provide "economically competitive production of electricity." Therefore, I assessed Station Two's capability of "economically competitive production of electricity" within the context of the MISO market.

Q. What is the future time horizon for your economic analysis of Station Two?

A. I estimated the future costs and MISO market revenues for Station Two over the period 2019 through 2035.

Q. How did you estimate the future energy generation from Station Two units in MISO?

A. For determining future energy generation from each unit, I simulated the economic dispatch and commitment of each unit at the plant against my projections of future MISO

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[8] *See* Direct Testimony of Robert W. Berry.
[9] *See* Direct Testimony of Robert W. Berry.
[10] *See* Direct Testimony of Robert W. Berry.

energy prices under several market outlooks. Economic dispatch refers to the level of generation output in each hour between the minimum and maximum generation levels to maximize the energy margins (i.e., energy revenues minus dispatch costs), assuming the unit has already started up and available to generate. Economic commitment refers to whether the unit would start-up or shut-down in each hour depending on the projected energy margins from economic dispatch, start-up costs, and constraints on minimum run-time and down-time. In addition, my projections on future energy generation reflect the scheduled outage days and forced outage rates. Big Rivers provided information on forced outage rates, dates of planned outages, start-up costs, minimum and maximum generation levels, and constraints on minimum run-time and down-time.

Q. How did you estimate the future avoidable costs of Station Two?

A. For the future annual fixed O&M and avoidable capital costs of Station Two, I relied on the information provided by Big Rivers. I estimated the future annual variable costs of operating Station Two by using my projections of future energy generation from each unit and the future delivered prices of coal and fuel-oil, as well as Big Rivers' projections on heat rates, variable O&M costs per MWh, and start-up costs for each unit at Station Two. Section D below provides a more detailed description of my assumptions on future avoidable costs of operating Station Two.

Q. How did you estimate the future revenues for Station Two in the MISO energy and capacity markets?

A. I estimated the future revenues from the MISO energy markets by using my projections for day-ahead energy prices at the Station Two units and economic dispatch (hourly generation) of the units at those energy prices. As I describe in the next section, future energy prices in MISO are uncertain due to uncertainty in key market fundamentals such as natural gas and coal prices. Therefore, I developed a Base Case outlook for future energy prices as well as several scenarios to reflect a reasonable range of uncertainty in long-term market fundamentals. I provide further details on my approach to estimate future energy market prices and revenues for Station Two in Section B below.

For estimating Station Two's capacity revenues in the MISO capacity market in the future, I developed a forecast for future capacity prices based on projected peak load, retirements and new generation additions in the market. Section C below describes my approach, key assumptions and results in more detail.

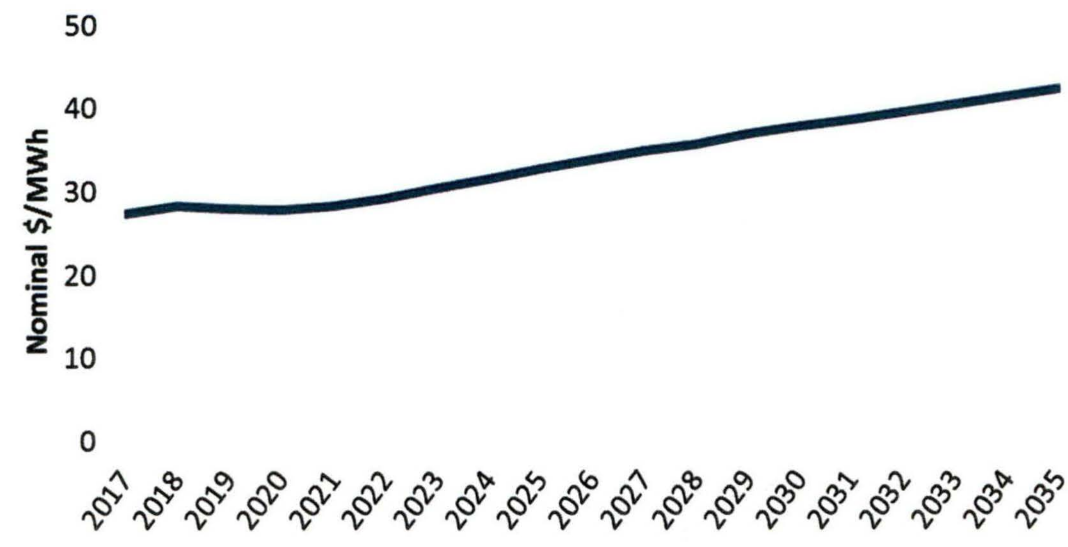
B. Future Energy Prices in MISO

Q. How did you estimate the future energy prices?

A. I projected the future energy prices for Station Two (day-ahead LMPs at the Station Two pricing locations) through 2020 based on recent market forwards for energy prices at Indiana Hub from the trading dates (April 9, 2018 through April 13, 2018), and adjusted these forward energy prices by the basis differential in 2017 between the day-ahead LMPs at Station Two and Indiana Hub. Beyond 2020, I estimated the energy prices at Station Two by escalating the projected prices in 2020 at the average growth rates for Henry Hub and regional delivered coal price forecasts that were recently developed by the U.S. Energy Information Administration (EIA) in the Annual Energy Outlook 2018 (AEO 2018) publication. For my Base Case outlook of future energy prices at Station Two beyond 2020, I relied on the post-2020 growth rates in natural gas and regional coal price forecasts in the "Reference" case of AEO 2018 since coal-fired and gas-fired units tend to set energy prices in the MISO region. I also assumed CO_2 prices to be zero during the study period in my Base Case outlook. Finally, I assumed the prices for SO_2 and NOx emissions allowances based on current market prices under the EPA's Cross State Air Pollution Rule (CSAPR) program, and assumed those prices to remain the same over the study period.

Figure 4 below shows my projections of all-hour average annual energy prices at Station Two pricing location under my Base Case outlook. I estimate the energy prices to remain near \$30/MWh (in nominal dollars) until 2023, then to increase gradually afterwards to about \$40/MWh in 2035 due to increasing fuel prices.

Figure 4: Projected All-Hour Average Annual Energy Prices at Station Two under Base Case



Source: Brattle analysis of EIA AEO 2018, and Illinois Hub day-ahead LMPs in 2017, and Illinois Hub power forwards from S&P Global Market Intelligence (SNL Energy Data).

Q. Why are CO_2 prices assumed to be zero over the entire study period in your Base Case outlook?

A. There is currently no existing or proposed federal or state regulation in the MISO region to assign a price to CO_2 emissions. Therefore, I assumed the CO_2 prices to be zero in my

Base Case outlook. However, as I describe below, I evaluated a scenario in which CO_2 emissions are greater than zero in future years.

Q. Why are SO_2 and NOx allowance prices assumed to remain the same over the study period?

A. I expect the future demand for SO_2 and NOx allowances to be flat or declining as a result of reduced generation from coal plants due to additional coal plant retirements in the future. EIA also expects in its AEO 2018 projections that the U.S. coal generation would decline from approximately 1,242 billion kWh in 2018 to 1,157 billion kWh in 2035.[11]

Q. Have you developed a range of future energy prices in addition to your Base Case outlook?

A. Yes, I did. Since there is substantial uncertainty in future energy prices as a result of uncertainty in major drivers of energy prices, I developed four scenarios in order to study the effect of key uncertainties on the economics of Station Two, including lower or higher natural gas and coal prices, potential carbon pricing, potential additional retirements of coal and nuclear plants in the MISO region, and potential additional revenues that coal plants could receive to maintain grid resiliency. Since some of the key uncertainties are interrelated (such as low gas prices would likely increase regional coal plant retirements and lower coal prices), combining internally consistent uncertainties results in four alternative scenarios. I summarize below the four scenarios I evaluated.

- Scenario 1 is the Low Gas Price scenario, which reflects lower gas prices and changes to other key assumptions from the AEO 2018 "High Oil and Gas

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[11] EIA – 2018 Annual Energy Outlook. Electric Power Projections by Electricity Market Module Region. Coal Reference Case.

Resource and Technology" case. The lower gas prices result in lower coal prices due to reduced demand for coal, reduced energy prices, and higher plant retirements due to reduced energy prices.

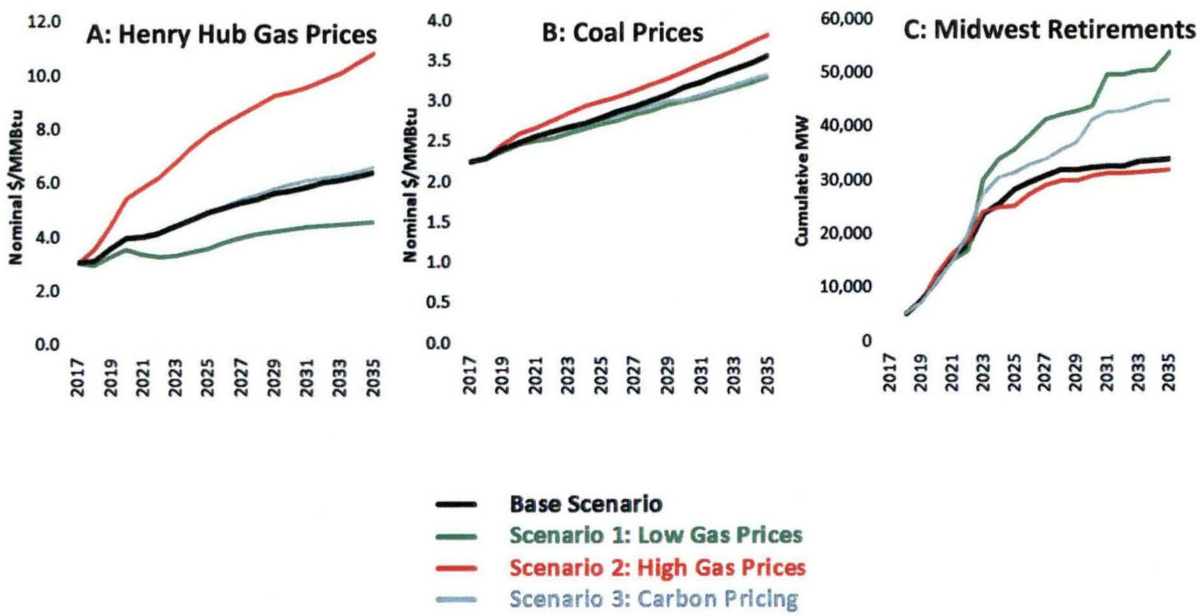
- Scenario 2 is the High Gas Price scenario, which reflects higher gas prices and changes to other key assumptions from the AEO 2018 "Low Oil and Gas Resource and Technology" case.
- Scenario 3 is the Carbon Pricing scenario, which reflects CO_2 emission prices starting in 2025 at $10/tonne, growing to $20/tonne by 2035, and changes to other key assumptions from the AEO 2018 "Reference Case with Clean Power Plan" case.
- Scenario 4 is the Additional Revenues For Baseload Plants scenario, which is based on the AEO 2018 "Reference Case," and assuming higher capacity prices to reflect potential revenues that coal plants could receive to maintain grid reliability.

Figure 5 below shows the Henry Hub natural gas prices (Panel A), regional delivered coal prices (Panel B), and plant retirements in Midwest[12] (Panel C) under the Base Case and four scenarios I evaluated. Under the Base Case projections, gas prices increase from the current level of about $3/MMBtu to about $6/MMBtu by 2035, and regional coal prices increase from $2.2/MMBtu to $3.5/MMBtu. Cumulative retirements in the Midwest region increase from about 5 GW in 2018 to 34 GWW by 2035. Under the High Gas Prices scenario, both gas and coal prices are higher than in Base Case, and

[12] I define the Midwest region as the combination of six EIA regions that include the MISO system, namely Reliability First Corporation (RFC) West, RFC Michigan, Midwest Reliability Council (MRO) East, MRO West, SERC Gateway and SERC Delta.

retirements are slightly lower. With the Low Gas Prices scenario, gas and coal prices are lower but retirements are larger compared to Base Case outlook. The Carbon Pricing scenario has gas and coal prices approximately the same as in Base Case, but the retirements are higher as a result of additional costs imposed on coal plants.

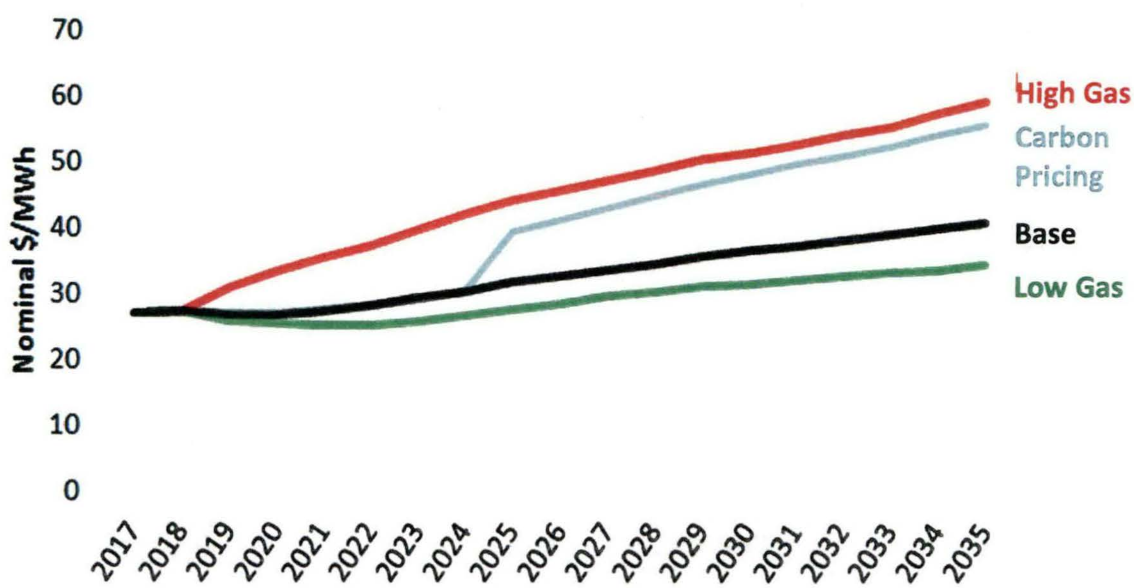
Figure 5: Projected Gas Prices, Coal Prices and MISO Retirements



Q. What is your resulting outlook for future energy prices at Station Two under your Base Outlook and the four scenarios you described above?

A. As shown in Figure 7 below, I estimate the future all-hour average energy prices increasing from about $27/MWh in 2017 to $41/MWh in 2035 under the Base Case, and in the range of $34-60/MWh in 2035 across the four scenarios I evaluated.

Figure 6: Projected All-Hour Average Annual Energy Prices at Station Two



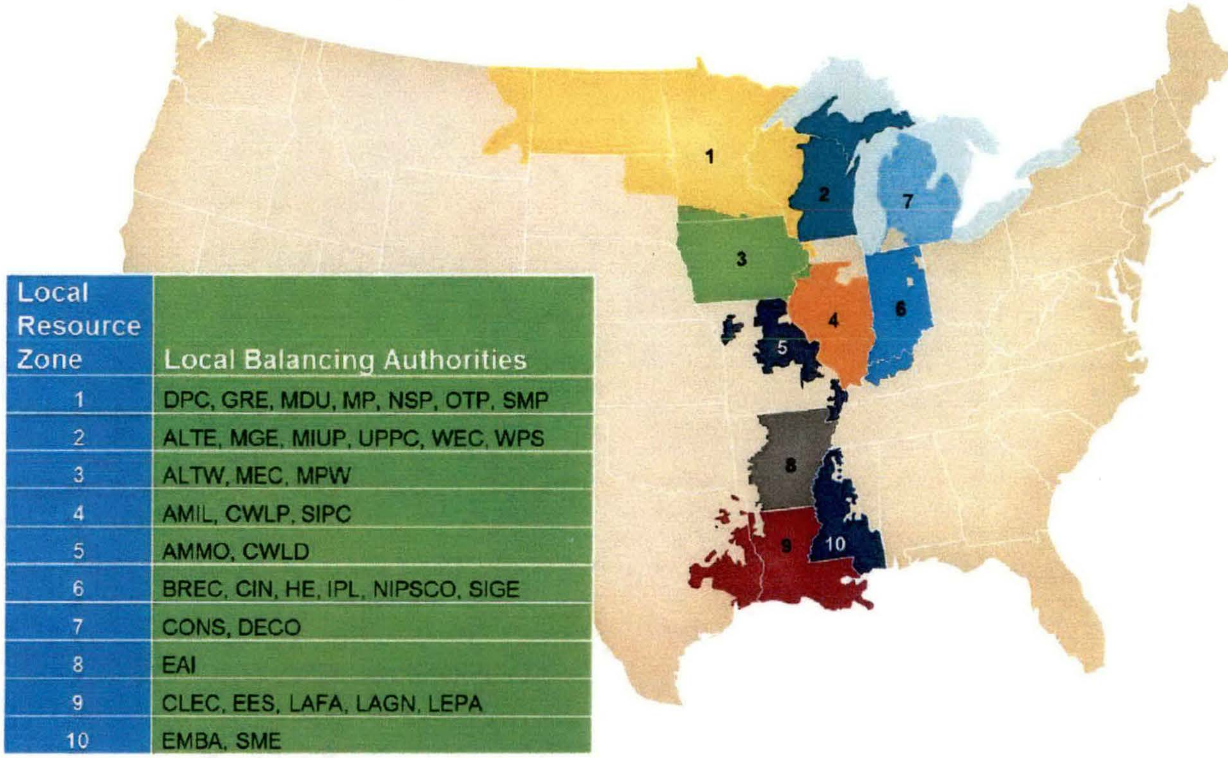
Source: Brattle analysis of EIA AEO 2018, Indiana Hub day-ahead LMPs in 2017, Indiana Hub power forwards from S&P Global Market Intelligence (SNL Energy Data).

C. Future Capacity Prices in MISO

Q. Please provide a brief background on the MISO capacity market.

A. MISO operates an annual capacity market called Planning Resource Auction (PRA) for maintaining resource adequacy in order to ensure that load serving entities (such as Big Rivers) have a sufficient amount of resources committed to be available to meet their anticipated peak demand requirements plus a required margin in the following year. By using the capacity offer prices submitted by each unit (including the Station Two units), MISO selects the resources that would be committed to provide capacity in the following year and determines location-specific capacity prices for each of the ten zones in the MISO region. Figure 7 below shows a map of the capacity zones in MISO. Station Two is located in Zone 6, hence the capacity price paid to Station Two is also the Zone 6 price.

Figure 7: Capacity Pricing Zones in MISO



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

Source: MISO, "Planning Year 2018-2019 Loss of Load Expectation Study Report", page 6.

Q. What were the historical prices in the MISO capacity market?

A. MISO's one-year ahead capacity market prices have fluctuated in the range of $1-26/kW-year range in Zone 6 (where Station Two is located) since 2013, and the latest auction for planning year 2018/19 (from June 2017 to May 2018) resulted in a price of $3.65/kW-year. The higher price of $26.28/kW-year observed in planning year 2016/17 coincided with a large amount of coal-fired capacity retirements (about 4,000 MW) and higher anticipated system peak load during that period.

Figure 8: MISO Historical Capacity Prices ($/kW-year)

Planning Year	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	**Zone 6**	Zone 7	Zone 8	Zone 9	Zone 10
2013/14	0.38	0.38	0.38	0.38	0.38	**0.38**	0.38	N/A	N/A	N/A
2014/15	1.20	6.11	6.11	6.11	6.11	**6.11**	6.11	6.00	6.00	N/A
2015/16	1.27	1.27	1.27	54.75	1.27	**1.27**	1.27	1.20	1.20	N/A
2016/17	7.20	26.28	26.28	26.28	26.28	**26.28**	26.28	1.09	1.09	1.09
2017/18	0.55	0.55	0.55	0.55	0.55	**0.55**	0.55	0.55	0.55	0.55
2018/19	0.37	3.65	3.65	3.65	3.65	**3.65**	3.65	3.65	3.65	N/A
Average	*1.83*	*6.37*	*6.37*	*15.29*	*6.37*	***6.37***	*6.37*	*2.50*	*2.50*	*0.82*

Source: MISO Planning Resource Auction Results.

Q. How did you estimate the future MISO capacity market prices in Zone 6?

A. For estimating the future market price of capacity in Zone 6, I relied on the current supply/demand outlook in MISO for future years and the latest data available on offer price curve from the MISO capacity auctions (PRA 2017/18). By using the announced generation retirements and additions as well as a recent MISO peak load forecast, I estimated the future capacity prices in each year at the intersection of my estimated future offer price curve with the future MISO peak load (plus planning reserve requirement). I also assumed that the interzonal capacity limits to be not binding, i.e., no price separation between Zone 6 and the other zones in MISO.

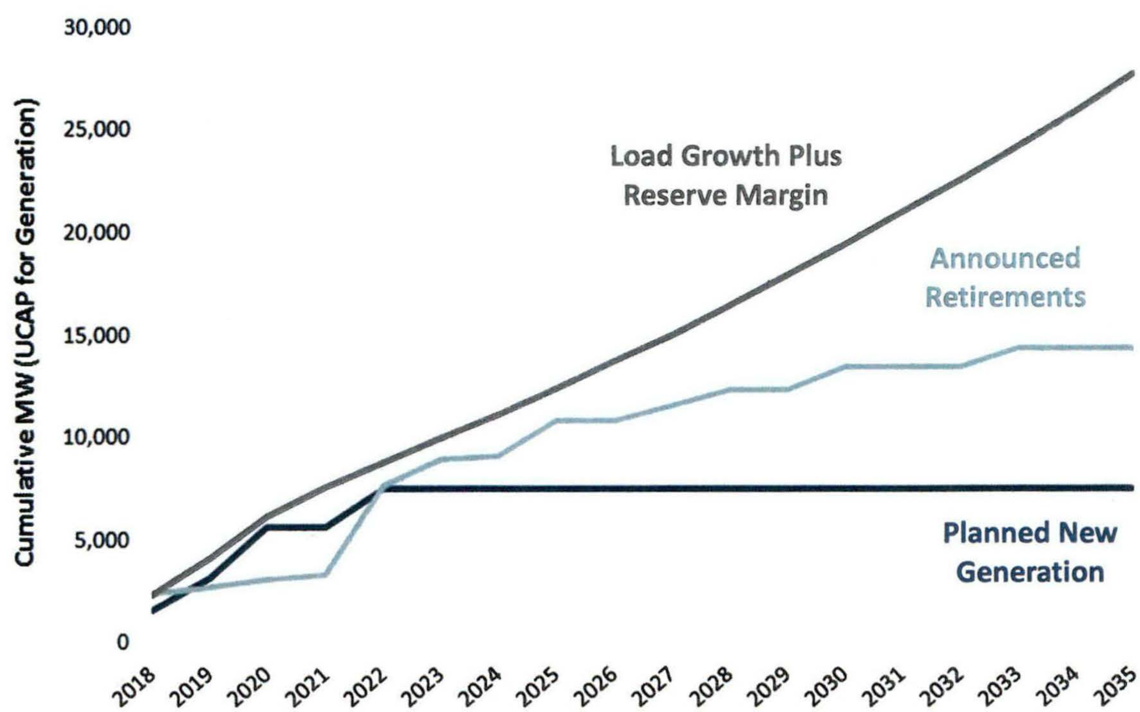
Q. Please describe your assumptions on future plant retirements, planned new generation, and change in MISO peak load.

A. As of April 2018, about 11 GW of existing generation capacity in MISO was announced for retirement by 2025, and another 3.5 GW to retire after 2025. Planned new generation of about 7.5 GW in advanced stages of development[13] is expected to come online by

[13] This includes planned units with the following status: under construction, testing, permitted, and application pending.

2025. Therefore, cumulative retirements net of new generation in MISO is currently expected to reach 3 GW by 2025 and 7 GW by 2035. This means that, even with no load growth in the future, MISO capacity supply/demand balance is expected to get tighter, likely resulting in upward pressure on future capacity prices. Based on a recent load forecast developed for MISO, peak load (plus required planning reserve margins) in MISO is expected to increase by about 13 GW between 2015 and 2025, and another 15 GW between 2025 and 2035. Figure 9 below shows the projected load growth, announced retirements and planned new generation in the MISO region.

Figure 9: Load Growth, Planned New Generation, and Announced Retirements in MISO Relative to 2017



Source: ABB, Inc., Velocity Suites (2018) and MISO Independent Load Forecast Update 2017.

Q. Do you expect the future load growth and net reduction in generation capacity you discussed above to result in MISO capacity prices to reach a level sufficient to attract new gas-fired merchant generation capacity?

A. No, I do not. The load-serving entities and generation owners in the MISO region are mostly regulated and vertically-integrated electric utilities that typically rely on their own resources (existing and new) to meet their required planning reserve margins. While many utility-owned coal plants have been retired and announced to retire in the future depending on the utilities' expected resource needs and economic viability of their plants, the replacement resources for these retiring coal plants eventually come from utilities' own resources, not from merchant entry. If a utility forecasts the total capacity in its own portfolio of resources to fall below the future peak load plus the planning reserve margin requirement (currently 8.4 percent[14]), the utility would plan in advance (typically 4-5 years before the expected need arises) to acquire or build additional generation capacity. Therefore, any new generation capacity needed for a future year would be committed and placed under construction years before the one-year-ahead MISO capacity auction. This would result in Zone 6 capacity prices (and most of the remaining zones in the MISO region) remaining substantially below current estimates for the cost of recovering the capital and fixed costs of new gas-fired merchant capacity in future years. MISO recently estimated the cost of new entry (CONE) for a new gas-fired combustion turbine plant to be in the range of \$83-91/kW-year depending on the location (and \$89/kW-yr in Zone 6).[15]

Q. Please explain your approach for estimating the future capacity prices in MISO.

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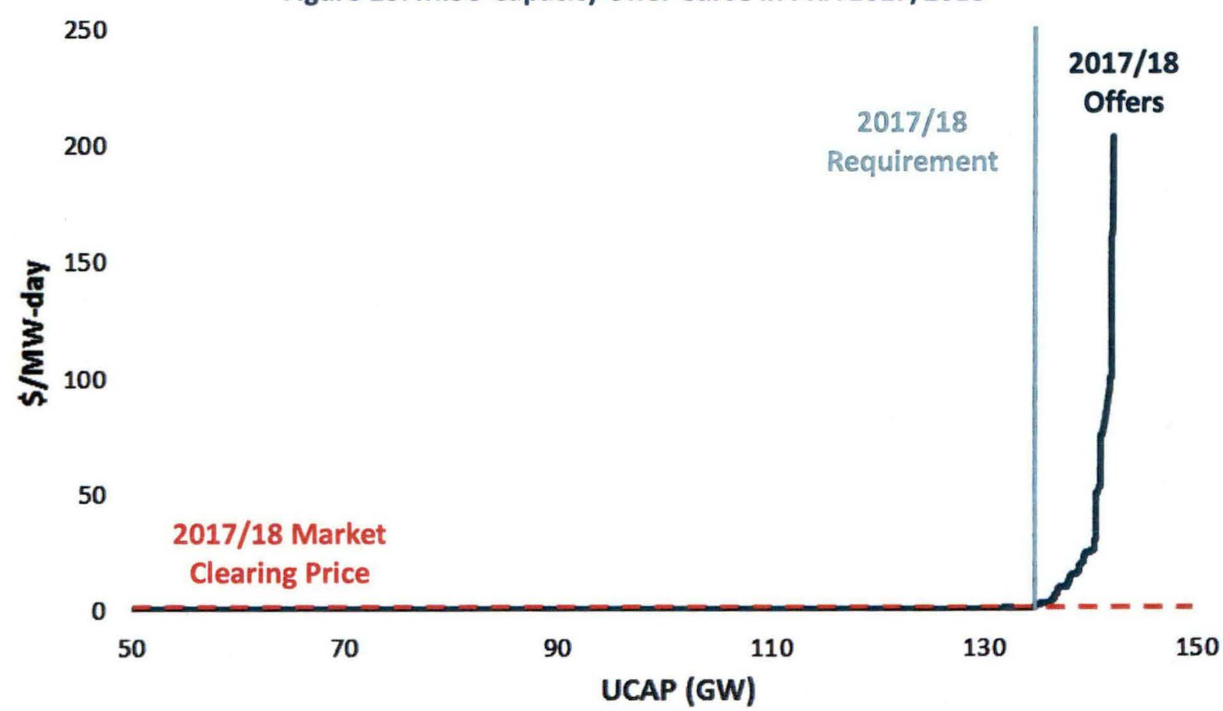
[14] MISO, Planning Year 2018-2019 Loss of Load Expectation Study Report, page 26, November 2017. MISO reports a Planning UCAP reserve margin of 8.4%.

[15] MISO Cost of New Entry PY 2018/19, Sept. 2017. https://cdn.misoenergy.org/20170913%20RASC%20Item%2002f%20CONE%20Filing%20Update87586.pdf

A. My approach uses the offer price curve and the total capacity procured in the 2017/18 MISO capacity auction as the starting point. As shown in Figure 10 below, the capacity offer price curve[16] in the 2017/18 auction exhibits very low (zero or near-zero) prices for most of the capacity offered, then increases sharply to about $204/MW-day for the highest-priced offers. The total procurement (or the planning reserve margin requirement, PRMR) in the 2017/18 auction was about 135 GW, shown as the vertical line in the chart. The market-clearing price in the auction was $1.50/MW-day, which is the price at the intersection of the offer curve and the total procurement (PRMR).

Figure 10: MISO Capacity Offer Curve in PRA 2017/2018



Source: MISO Planning Resource Auction Results.

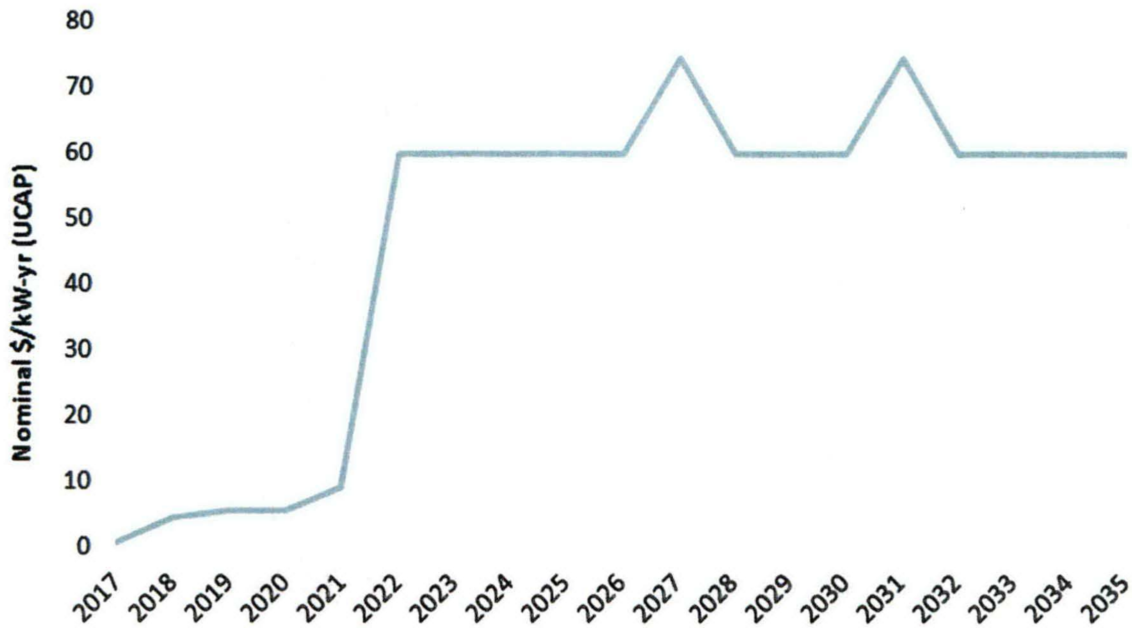
[16] The offer price curve shown includes capacity (about 49 GW total) under Fixed Resource Adequacy Plan (FRAP) mechanism that are used by utilities that did not participate in the capacity auction for meeting their resource adequacy obligations.

For future years, I adjusted the offer price curve with announced retirements (by removing that capacity from the offer curve) and with planned new generation (by adding that capacity at zero price to the offer curve). I also adjusted (increased) the future PRMR by the projected increase in MISO peak load (plus reserve margin requirement) for each future year. I estimate the future capacity prices for each year as the offer price at the intersection of the offer curve and the PRMR for that year. I assumed that any new generic capacity to meet future load requirements would come in as a price taker since the regulated utilities in most of the MISO zones would plan for (and start constructing) those new resources in advance of the one-year ahead capacity auction.

Q. What are your resulting capacity price projections for Zone 6?

A. As shown in Figure 11 below, I estimated the future capacity prices to increase from $3.65/kW-yr in the 2018/19 auction to about $60/kW-yr in 2022 and mostly remain in the range of $60-75 /kW-year in future years.

Figure 11: Projected Capacity Prices in Zone 6



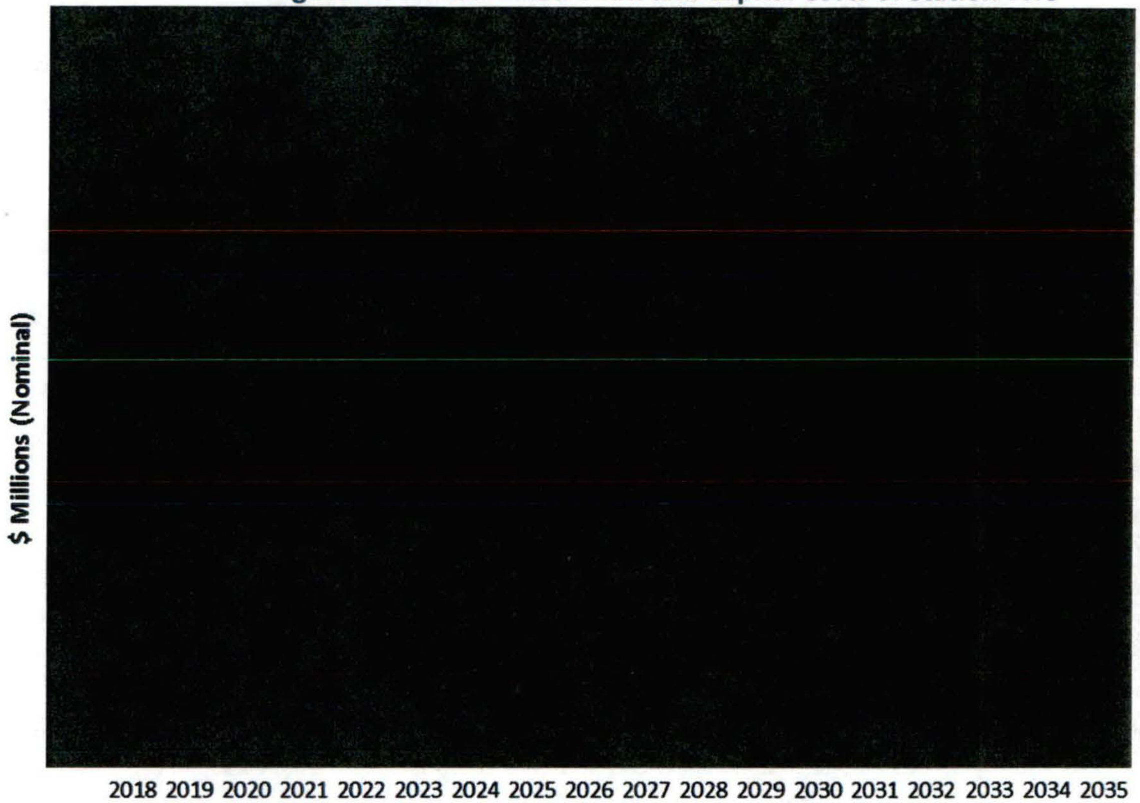
Source: Brattle analysis of MISO Planning Resource Auction Results, 2018 LOLE Study Report, MISO Cost of New Entry PY 2018-2019, MISO Independent Load Forecast Update 2017, and ABB, Inc., Velocity Suites (2018)..

D. Future Costs of Operating Station Two

Q. Please describe your assumptions on future fixed O&M and capital costs for Station Two.

A. The annual fixed O&M costs of Station Two are projected to increase from [redacted] in 2018 (or [redacted]) to [redacted] in 2035 (or [redacted]) in nominal dollars. The avoidable capital costs for Station Two are projected to increase from [redacted] in 2018 (or [redacted]) to [redacted] in 2035 (or [redacted]). Figure 12 below shows the annual fixed O&M and capital cost assumptions for the period 2018 through 2035.

Figure 12: Annual Fixed O&M and Capital Costs of Station Two



[redacted]

Source: 2018-2031 Fixed O&M and Capex values provided by Big Rivers Electric Corporation.

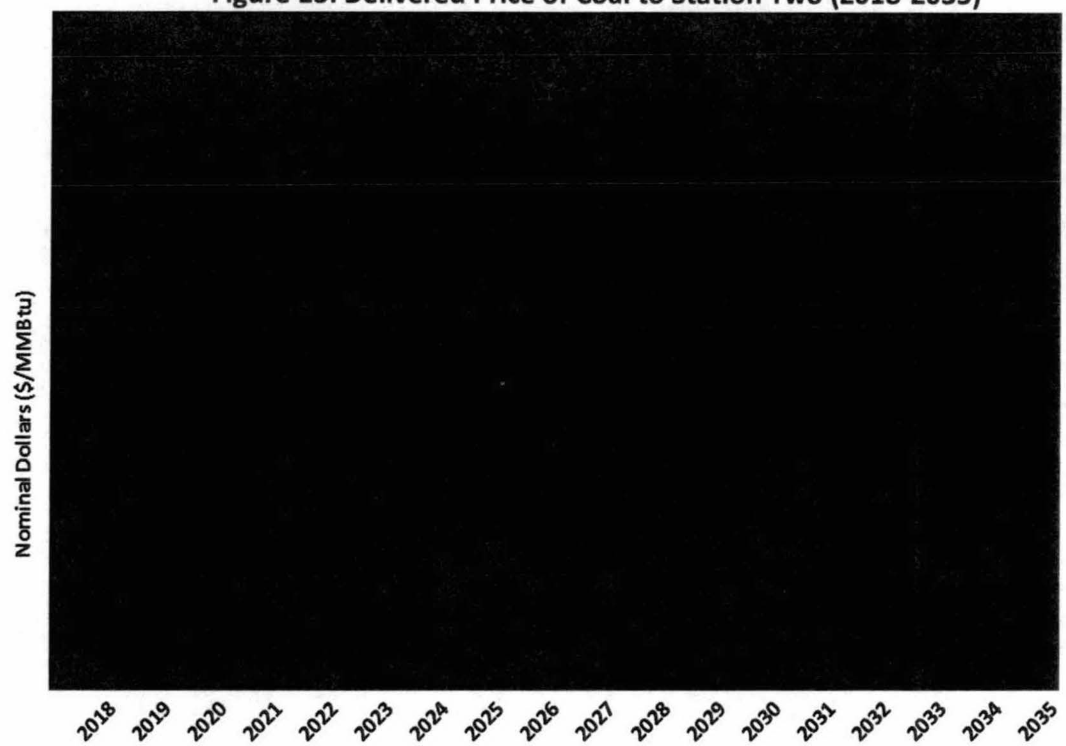
Note: Series extended based on the average growth rate of the last five years of provided data.

Q. Please describe your assumptions for deriving the future variable costs of operating Station Two.

A. Future variable costs of operating Station Two units consist of fuel (coal) costs, variable O&M costs, start-up costs, mill cycle costs, and emissions allowance costs. I describe my assumptions for each of these below.

I estimated the future fuel costs by using my forecasts for delivered price of coal to Station Two and for annual generation (economic dispatch) from Station Two. For estimating delivered price of coal under my Base Case outlook, I escalated Big Rivers' estimated delivered price for 2018 by the growth rate in regional delivered coal price forecast from AEO2018 Reference Case. The resulting delivered price of coal to Station Two is shown in Figure 13 for the period 2018 through 2035.

Figure 13: Delivered Price of Coal to Station Two (2018-2035)



Source: 2018 Coal Fuel Price provided by Big Rivers, Future growth based on 2018 EIA AEO, Electric Power Projections by Electricity Market Module for "RFC West – Coal Reference Case".

For estimating the future variable O&M costs, I relied on Big Rivers' projections that grow from [redacted] in 2018 to [redacted] in 2035 in nominal dollars. I find these projections to be reasonable.

Future start-up costs depend on the number of starts per year, the delivered price of fuel-oil for each start, and the amount of fuel-oil consumption for each start. I estimated the future number of starts based on my simulation of economic dispatch and commitment of Station Two units. For the delivered price of fuel-oil in future years under my Base Case outlooks, I escalated Big Rivers' estimated delivered price for 2018 by the growth rate in regional delivered fuel-oil price forecast from AEO2018 Reference Case. Big Rivers provided the data on fuel-oil consumption for each start. In 2018, the resulting start-up costs are about [redacted] for hot start (less than 40 off hours), about [redacted] for intermediate start (between 41-72 off hours), and about [redacted] for cold start (greater than 72 off hours).

Mill cycle costs refer to cost of additional fuel-oil consumption if the generation output in each unit increases above 110 MW. Based on data provided by Big Rivers, this fuel-oil consumption associated with mill cycle is [redacted] for Unit 1 and [redacted] for Unit 2.

Finally, since generation from Station Two units result in SO_2 and NOx emissions, I developed an estimate for future prices of emissions allowances for compliance with EPA's Cross State Air Pollution Rule (CSAPR) cap-and-trade program. Current prices of these emissions allowances are low: $2.13/tonne for CSAPR Region 1 SO_2 allowance prices, $2/tonne for CSAPR annual NOx allowance prices, and $162.5/tonne for CSAPR Seasonal NOx allowance prices. Since I expect the demand for these allowances from the covered fossil-fired units in the U.S. to decrease in the future (as a result of announced and expected coal plant retirements), I assumed the future prices of SO_2 and NOx allowances to remain the same as the current prices in nominal dollars. Since Station Two's SO_2 and NOx emissions rates are low (about 0.26 lbs/MMBtu for SO_2 and less than 0.5 lbs/MMBtu for NOx), the impact of the emissions allowance prices on Station Two's dispatch costs are minimal at the current prices.

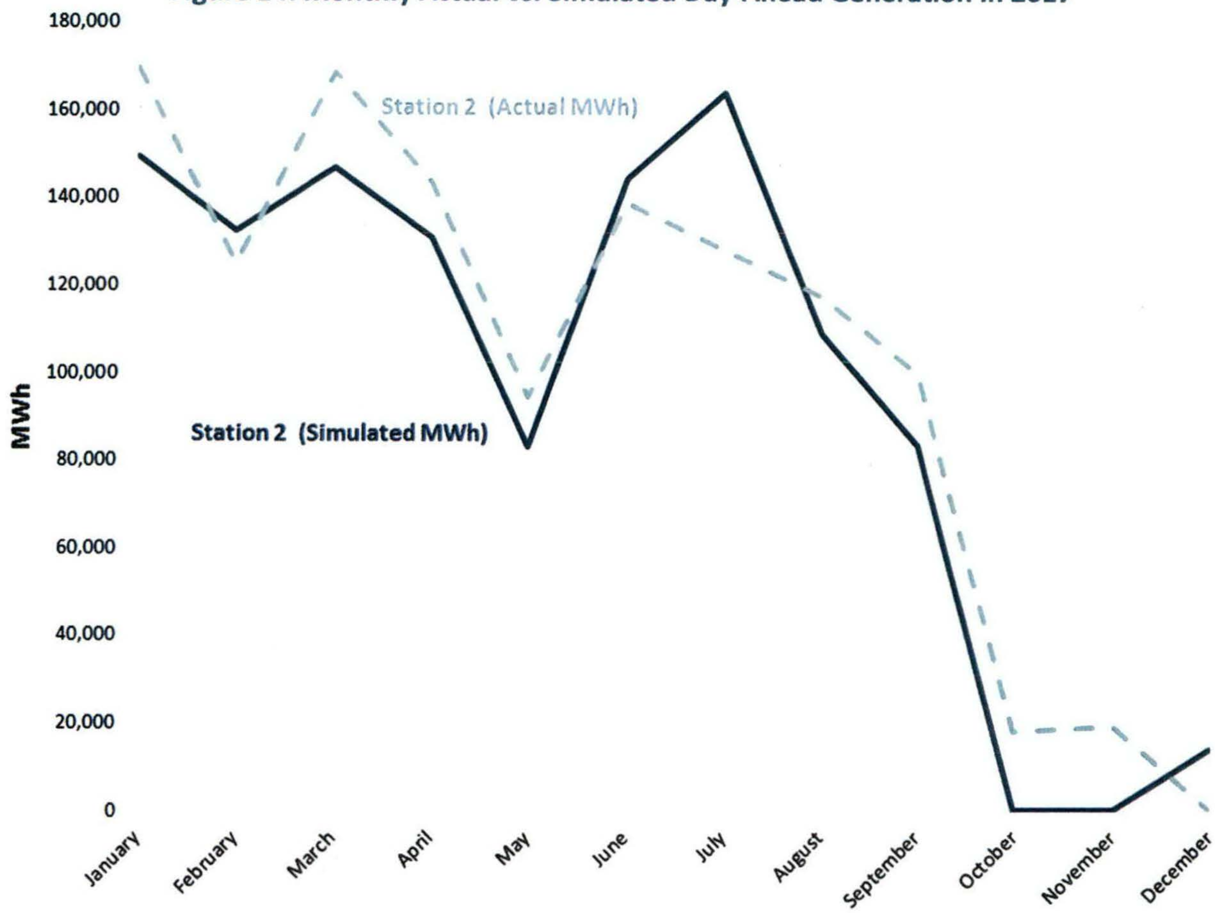
E. Calibration of Station Two Economic Dispatch to 2017 Actuals

Q. Have you assessed whether your approach to estimate the economic dispatch and commitment of Station Two results in a similar level of annual generation to actual historical generation?

A. Yes. I estimated the hourly economic dispatch of each unit against the actual hourly day-ahead energy prices in 2017 at the pricing locations of the Station Two units. Specifically, I estimated the amount of energy that would be economic to generate at each of the two units in each hour in 2017 by taking into account the information on marginal cost of producing energy from each unit, constraints on unit operations (such as minimum load, minimum run-time, minimum down time, start-up costs, and mill-cycle costs), and outages. Big Rivers provided actual 2017 data for Station Two's forced and scheduled outages, actual hourly generation and day-ahead schedules, heat rate curves, variable O&M cost per MWh of output, coal prices, monthly incremental dispatch costs, and monthly production costs.

Figure 14 below compares my estimated generation from Station Two units in the day-ahead market against generation actually selected (i.e., cleared) in the MISO day-ahead market in 2017 on a monthly basis. The simulated generation closely approximates the actual day-ahead scheduled generation, and decreases sharply starting in October 2017 when operation of both units were switched to economic commitment.

Figure 14: Monthly Actual vs. Simulated Day-Ahead Generation in 2017



VI. RESULTS

Q. Please summarize the results of your analysis under your Base Case outlook for future market conditions.

A. Figure 15 below presents the results of my analysis under the Base Case outlook, and shows that Station Two's projected gross margins are negative in all years during the study period. In other words, over the study period of 2019-2035, Station Two's projected variable and fixed costs exceeded its projected revenues. This result is largely driven by large fixed O&M and CapEx costs for the plant (about [redacted] per year on average) that are substantially higher than the sum of projected energy margins (about [redacted] per year on average) and capacity revenues (about [redacted] per year on average) in the MISO markets.

In addition, at any reasonable level of discount rate, the net present value of Station Two's gross margins as of the beginning of 2018 is negative. Figure 15 below uses a discount rate of 8%, resulting in a gross margin of negative [redacted].

Figure 15: Station Two Gross Margins under Base Case Outlook (8% Discount Rate)

		Units	2019	2020	2025	2030	2035
[1]	Generation	MWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[2]	Capacity Factor	%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[3]	Number of starts		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[4]	Fuel Costs	$m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[5]	VOM	$m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[6]	Startup Costs	$m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[7]	Mill Cycle Costs	$m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[8]	Allowance Costs	$m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[9]	Total Variable Costs	$m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[10]	Total Variable Costs	$/MWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[11]	Energy Price	$/MWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[12]	Energy Revenues	$m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[13]	Energy Revenues	$/MWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[14]	Energy Margin ($)	$m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[15]	Energy Margin ($/MWh)	$/MWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[16]	Fixed O&M and CapEx	$m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[17]	Fixed O&M and CapEx	$/kW-yr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[18]	Capacity Price (UCAP)	$/kW-yr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[19]	UCAP Capacity	MW	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[20]	Capacity Revenues	$m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[21]	Capacity Revenues (ICAP)	$/kW-yr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[22]	Gross Margin	$m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[23]	Gross Margin	$/kW-yr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[24]	Gross Margin (PV Beginning 2018)	$m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Q. What is the basis for using a discount rate of 8%?

A. For conservatism, I have used a discount rate corresponding to the risk faced by Big Rivers is reliance on market sales of energy and capacity. This can be estimated with reference to publicly traded companies engaged in similar activities ("Merchant Generators"). A recent estimate of the cost of capital facing Merchant Generators was performed by The Brattle Group in a public study on behalf of PJM. Brattle concluded based on recent data that the after-tax weighted average cost of capital facing Merchant Generators is 7.5%.[17]

Q. Have you compared the economics of early retirement for Station Two?

A. Yes. For that assessment, I considered the potential savings from delaying the retirement to later years in addition to the present value of gross margins for Station Two from operating Station Two during the study period. The decommission cost assumptions are based on the estimated decommissioning costs for Big Rivers' Coleman plant from a 2016 study performed by Burns & McDonnell. In the Burns & McDonnell study, the cost of decommissioning the Coleman plant (602 MW) in 2016 was estimated to be [redacted], or about [redacted]. As an approximation, I assumed the same decommissioning costs in $/kW for Station Two, resulting in an estimated cost of [redacted] for decommissioning the plant in 2016. Assuming 1% per year escalation in decommissioning costs in real dollars, this yields [redacted] to decommission Station Two at the end of 2018, and [redacted] to decommission Station Two at the end of 2035. In present value terms at an 8% discount rate, delaying the decommissioning from

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17 The after-tax weighted average cost of capital is the discount rate appropriate for valuing a future stream of gross margins as defined herein. *See* The Brattle Group, "PJM Cost of New Entry Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date", April 19, 2018, at page 36, posted at http://www.pjm.com/-/media/library/reports-notices/special-reports/2018/20180420-pjm-2018-cost-of-new-entry-study.ashx?la=en.

2018 to 2035 would result in about [redacted] in cost savings.

Figure 16 below compares the present value of gross margins and decommissioning costs at different retirement years starting at the end of 2018. If the plant retires at the end of 2018, the present value of plant's gross margins during the period 2019-2035 would be zero and the present value of decommissioning costs would be [redacted]. This results in negative [redacted] for present value of gross margins net of decommissioning costs. But if the plant continues to operate in future years, the present value of financial losses increase further, reaching a negative [redacted] for retirement at the end of 2035, i.e., about [redacted] financial losses relative to retiring at the end of 2018.

Figure 16: Gross Margin Net of Decommissioning Costs ($millions at 8% Discount Rate)

Retirement at End of Year	PV of Gross Margins [1]	PV of Decomm Costs [2]	Gross Margin Net of Decomm Costs [3]
2018	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]
2031	[redacted]	[redacted]	[redacted]
2032	[redacted]	[redacted]	[redacted]
2033	[redacted]	[redacted]	[redacted]
2034	[redacted]	[redacted]	[redacted]
2035	[redacted]	[redacted]	[redacted]
2035 minus 2018	[redacted]	[redacted]	[redacted]

Note: [3]=[1] –[2].

Therefore, retirement of Station Two at the end of 2018 results in the highest present value gross margin, even net of the cost of accelerating the decommissioning costs, and every year that retirement is delayed results in a less favorable present value gross margin. Thus, Station Two is not capable of economically competitive production of electricity under my Base Case outlook for future market conditions.

Q. Have you conducted a sensitivity analysis of your findings with respect to your assumed discount rate?

A. Yes. My assumed discount rate of 8% reflects approximately the typical cost of capital for a merchant generation owner. As a sensitivity, I assumed an alternative discount rate of 5%. With a lower discount rate, the present value of future negative gross margins for Station Two becomes higher, and therefore the costs of delaying the retirement of Station Two becomes larger.

Figure 17: Gross Margin Net of Decommissioning Costs ($millions at 5% Discount Rate)

Retirement at End of Year	PV of Gross Margins [1]	PV of Decomm Costs [2]	Gross Margin Net of Decomm Costs [3]
2018	[redacted]		
2019			
2020			
2021			
2022			
2023			
2024			
2025			
2026			
2027			
2028			
2029			
2030			
2031			
2032			
2033			
2034			
2035			
2035 minus 2018			

Q. How would your results change under the four market scenarios you evaluated?

A. In all market scenarios I evaluated, delaying the retirement of Station Two from the end of 2018 to 2035 results in financial losses. Figure 18 below shows the results across all scenarios. As I described above, under the Base Case outlook, delaying the retirement results in about [redacted] financial losses. In the four scenarios, the cost of delaying retirement ranges from about [redacted] to [redacted].

Figure 18: Economics of Retiring Station Two in 2018 vs. 2035 (8% Discount Rate)

	Description	Units	Scenarios				
			Base Case	1 - Low Gas Prices	2 - High Gas Prices	3 - Carbon Pricing	4 - Additional Revenue for Baseload
[1]	Annual Average Capacity Factor	%	[redacted]				
[2]	Market Revenues for Station Two	$m					
[3]	Energy	$m					
[4]	Capacity	$m					
[5]	Total Market Revenues	$m					
	Less:						
[6]	Avoidable Costs of Station Two						
[7]	Fuel	$m					
[8]	Variable O&M	$m					
[9]	Allowance Costs	$m					
[10]	Fixed O&M	$m					
[11]	Ongoing Capex	$m					
[12]	Deferred Decomm from 2018 to 2035	$m					
[13]	Total Costs	$m					
[14]	**Net Revenues [5] - [13]**	**$m**					

Q. Have you evaluated the economic viability of operating one of the two units at Station Two, rather than both of the units?

A. Yes. Assuming that the unit with the higher dispatch cost (Unit 2) retires early, I evaluated whether operating only Unit 1 in the future would be economically viable. For that sensitivity, I reduced the projected annual fixed O&M and capital costs of operating Station Two to reflect the operations of only Unit 1 based on information provided by Big Rivers. I also assumed that the decommissioning of Unit 2 would take place at the end of 2018. I conclude that operating Unit 1 until the end of 2035 while retiring Unit 2 at the end of 2018 would not result in Station Two being capable of normal, continuous, reliable operation for the economically competitive production of electricity. Note that the net revenue impacts of delaying retirement of Unit 1 are disproportionately larger (i.e., more than half) compared to the Station Two results shown in Figure 18. This is due to an increase in fixed costs per kW for Unit 1 if Unit 2 retires at the end of 2018.

Figure 19: Economics of Retiring Unit 1 at Station Two in 2018 vs. 2035 (8% Discount Rate)

	Description	Units	Scenarios: Base Case	Scenarios: 1 - Low Gas Prices	Scenarios: 2 - High Gas Prices	Scenarios: 3 - Carbon Pricing	Scenarios: 4 - Additional Revenue for Baseload
[1]	Annual Average Capacity Factor	%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[2]	Market Revenues for Station Two	$m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[3]	Energy	$m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[4]	Capacity	$m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[5]	Total Market Revenues	$m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Less:		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[6]	Avoidable Costs of Station Two		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[7]	Fuel	$m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[8]	Variable O&M	$m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[9]	Allowance Costs	$m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[10]	Fixed O&M	$m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[11]	Ongoing Capex	$m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[12]	Deferred Decomm from 2018 to 2035	$m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[13]	Total Costs	$m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[14]	**Net Revenues [5] - [13]**	**$m**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

VII. CONCLUSIONS

Q. Do you have any closing comments?

A. Yes. In every year of the study period and under every scenario we evaluated, Station Two's projected costs exceed its potential energy and capacity revenues resulting in negative net revenues each year, and each year that either or both of the Station Two units continue to operate produces a worse result. It does not make economic sense to continue to operate either or both of the Station Two units because Station Two is not capable of economically competitive production of electricity.

Q. Does this conclude your testimony?

A. Yes, it does.

BIG RIVERS ELECTRIC CORPORATION

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. 2018-00_____

VERIFICATION

I, Metin Celebi, verify, state, and affirm that I prepared or supervised the preparation of my Direct Testimony filed with this Verification, and that Direct Testimony is true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Metin Celebi

Metin Celebi

COMMONWEALTH OF MASSACHUSETTS)
COUNTY OF SUFFOLK)

SUBSCRIBED AND SWORN TO before me by Metin Celebi on this the 27th day of April, 2018.

Erica L Deary

Notary Public, Massachusetts

My Commission Expires February 15, 2024

ERICA L. DEARY
Notary Public
COMMONWEALTH OF MASSACHUSETTS
My Commission Expires
February 15, 2024

ERICA L. DEARY
MY COMMISSION EXPIRES FEB. 15, 2024
NOTARY PUBLIC
COMMONWEALTH OF MASSACHUSETTS

Exhibit Celebi-1 – Resume

METIN CELEBI
Principal

Boston, MA +1.617.864.7900 Metin.Celebi@brattle.com

Dr. Metin Celebi provides expertise in electricity markets, resource planning, and analysis of environmental and climate policy. He has consulted and testified primarily in the areas of economic viability of coal-fired and nuclear power plants, wholesale power pricing and market design, and has experience in developing and analyzing federal/state climate policies, environmental regulations, LMP modeling, generation plant valuation and competitive implications of mergers. His recent engagements include economic viability assessments for coal plants, estimating above-market costs of U.S. DOE's proposed payments to merchant generation plants, impacts of implementing marginal losses in the ERCOT market, economic damages in energy contracts, impacts of retiring coal plants on power markets, and cost/benefit assessment of RTO membership to electric utilities. Dr. Celebi has also experience in the estimation and implementation of marginal costs in ratemaking for electric utilities.

Dr. Celebi provided expert testimony in regulatory cases involving the wholesale power prices in Arizona, long-term power contract dispute in California, impact of coal plant retirements on wholesale energy prices in MISO, LMP spikes in PJM, and allocation of certain ancillary services costs among market participants in ERCOT.

EDUCATION

Dr. Celebi received his Ph.D. in Economics from Boston College in the field of industrial organization and applied econometrics. His Ph.D. dissertation thesis explored the incentives of transmission owners to provide transmission capacity and reliability in deregulated electricity markets, and characterized the optimal regulation of capacity and reliability in an incomplete information setting. He received his Master in Economics from Bilkent University in Ankara, Turkey, and a B.S. in Industrial Engineering from Middle East Technical University (METU) in Ankara, Turkey.

AREAS OF EXPERTISE

- Coal Plant Economics – Viability, Retirements and Market Impacts
- Resource Planning for Electric Utilities
- Environmental and Climate Policies - Design and Implications
- Wholesale Electric Market Analysis and Asset Valuation
- Energy Litigation
- Retail Electric Rates - Cost Estimation and Recovery

EXPERIENCE

COAL PLANT ECONOMICS – VIABILITY, RETIREMENTS AND MARKET IMPACTS

- For a municipal electric utility in the MISO market region, evaluated the economic viability of an existing coal plant against the projected wholesale power prices in MISO. By using an in-house plant dispatch and commitment modeling tool, estimated the future annual capacity factor and variable costs of operating the plant, and compared the plant's avoidable future costs against the projected market prices of energy and capacity for the plant. Developed scenarios for future market prices by considering the key uncertainties such as natural gas prices and potential implementation of a CO_2 emissions prices. Estimated the savings from a potential early retirement of the coal plant.
- For an investor-owned electric utility in the MISO market region, assessed the potential for economic early retirement of a coal-fired plant under several scenarios including potential future requirements for retrofitting the plant with SO_2 emissions control equipment and future wholesale power market conditions. Estimated the likely impact of retrofits and early retirement on the utility's revenue requirements and retail rates.
- For an electric utility considering an early retirement for one of its coal plants, provided regulatory support to describe the changing economic viability of the existing coal plants in the U.S. wholesale power markets over the last decade. Conducted research on regulatory decisions in various state jurisdictions on recovery of past investments at retiring generation plants, and explained the perverse incentives on retirement decisions that would be created by disallowing prudently incurred past investments.
- For a merchant generation company in PJM, assessed the potential impacts of coal plant retirements on future likely range of energy prices under key uncertainties for market fundamentals. In addition, the project team evaluated whether the recent price spikes under the extreme weather and system conditions can be repeated in the future with increasing reliance on gas-fired generation plants.
- For an electric utility in Wisconsin, provided expert testimony on the likely changes in energy and capacity prices as a result of projected coal plant retirements and environmental retrofits in the MISO region. The analysis included a transparent model to estimate the impacts of retirements and retrofits on the regional supply curve, and the impacts of nationwide coal retirements on natural gas prices. Reviewed the projected reserve margins in

the MISO region with and without the coal retirements to evaluate the likely changes in capacity prices in the MISO region after 2016.

- Conducted a screening analysis of coal-fired units in the United States for producer of a fuel that could be an alternative to burning coal in generating units in order to avoid or mitigate future compliance requirements with environmental regulations. The analysis compared the projected costs for each unit under the coal-fired operations (including the retrofit cost of environmental control equipment) against the costs under operations with the alternative fuel and the costs of replacement with a new gas-fired unit.
- For American Coal Ash Association, conducted annual surveys for the production and use of coal combustion residuals in the U.S. The Brattle team designed and implemented the survey that is circulated to coal generation plant operators, and supplemented that information with Brattle's assessment of key market trends in the power industry. The results of the survey are published each year for consumption by energy and environmental agencies and industry analysts.
- For an investor, assessed the economic viability of selected merchant and regulated coal plants in the Midwest. The analysis focused on estimates of projected net revenues for merchant plants, and cost of continued operations of the regulated coal plants against replacement power costs. In addition, estimated the projected capacity factor and coal use by each plant under selected future gas and CO_2 price sensitivities.
- Managed a case regarding the estimation of cost and performance benchmarks for two coal-fired generation plants in the Eastern U.S. We assessed their performance and cost by comparing them with similar coal plants in the country with respect to various performance metrics (heat rate, availability, forced outage rate, etc.) and cost metrics (fuel cost, maintenance costs, capital expenditure). We identified the strong and the weak points, by using various definitions of total costs and key performance metrics, and we analyzed the tradeoff between good performance and high costs among peer group plants.

Resource Planning for Electric Utilities

- For a large Midwest utility serving electric and gas, assessed current and likely future industry developments with potential to create opportunities and risks for the regulated and nonregulated operations of the company. The key developments included emerging EPA air quality, water and ash regulations for power plants, potential climate policies, macroeconomic recovery, and smart grid technologies. In addition, conducted a thorough comparison of the risks and cost of capital associated with regulated and unregulated businesses, including behind-the-meter renewable generation. Presented the findings of these assessments to the Board of Directors.

- Assisted a municipal electric utility in developing a least-cost strategy to comply with the environmental regulations. Developed a screening tool to compare the economics of environmental retrofits against alternatives such as replacement with a new gas-fired combined cycle or relying on market purchases of energy and capacity to meet the retail load obligations. Presented the results of the economic analysis and potential hedging strategies to the executive management.
- Co-authored a chapter of a recent EPRI report on decision-making complexities and factors in utility resource planning and environmental compliance investment decisions. The chapter described how various metrics of cost and performance are used by power industry planners and executive decision makers, what some of the limitations of those metrics and modeling techniques are, and how this problem and modeling complexity may alter the type and timing of technology preferences. Some of the complexities are illustrated with a couple of examples on retire/retrofit choices for coal plants to comply with the environmental regulations and on decision-making for Carbon Capture and Sequestration (CCS) investment under CO_2 price volatility.
- Assisted an electric utility in the Midwest in their resource planning. Developed environmental regulation scenarios with the executives and experts at the utility, and assisted in modeling and reviewing the implications of regulatory and market scenarios on the least-cost strategy subject to meeting load, renewable energy standards, and capital constraints. The strategy options included retrofitting the coal-fired generation plants with necessary control equipment, retirement of coal-fired units and replacement with gas-fired units. Presented the results to the utility executives.
- Assisted an electric utility in developing an Integrated Resource Plan under potential climate policy scenarios. The plan was developed by reviewing and choosing the best mix of supply-side alternatives and demand-side programs that would achieve the joint objectives of minimizing cost and mitigating CO_2 footprint subject to meeting the utility's obligation to serve its customers. The supply-side options included combinations of conventional generation technologies, renewables and low-CO_2 fossil-fired generation, and new transmission investment.

- For a large independent generation company, led a team to assess the reasonableness of the evaluation procedures and criteria used by an electric utility in the Southern U.S. in its RFP to acquire new generation assets and PPAs. The team reviewed the RFP requirements and the workpapers supporting the RFP results in a short period of time to identify the questionable assumptions and criteria used by the electric utility, and quantified the impacts of these on the relative costs of bids.
- For EPRI, analyzed and reviewed the major drivers of generation technology choice in various countries and regions around the world. Although the availability and degree of access to fuels is a common driver, other factors such as capital cost, attitude towards nuclear technology and renewables, constraints on carbon-intensive technologies, and degree of economic development play varying degrees of roles in the choice of generation fuels and technologies in each country.

Environmental and Climate Policies - Design and Implications

- For a merchant generation owner in New England, managed a team to conduct an economic study on the potential cost and emission impacts of making the existing clean energy generators eligible under an expanded Clean Energy Standard (CES) program in Massachusetts. Under the existing CES program, commercial operating date requirements limit eligibility to clean energy generators commencing operation after 2010. The study concluded that retaining existing clean generation that came online prior to 2010 under the CES program would reduce GHG emissions in Massachusetts and New England, and would reduce system production and customer costs.
- For a power industry association, co-authored a study to assess the carbon emission impacts of premature nuclear retirements. The study concluded that the vulnerability of some nuclear power plants to premature retirement could create a major threat to the attainment of desired CO_2 reduction. The analysis found that the retirement of a 1,000 megawatt nuclear plant could increase CO_2 emissions in the range of 4.1 to 6.7 million tons per year, or 0.52-0.84 tons per MWh of nuclear generation lost, depending on the region in which the nuclear retirement occurs. In addition, the increased level of CO_2 emissions arising from a premature nuclear retirement is not confined to the state in which the unit resides. In fact, in most cases the majority of this increase will occur outside the state, and a significant amount of the

emissions increase will occur in states beyond those adjacent to the state experiencing the retirement.

- For an industry association, co-authored a study to analyze the potential implications for competitive wholesale electricity markets if new gas-fired combined cycle (CC) plants are not covered under the Clean Power Plan's (CPP) mass-based state implementation plans (SIPs). The authors found that if state implementation plans exclude new gas CC plants, the electric sector could fall short of the carbon dioxide (CO_2) reduction goals set by the CPP, while incurring higher system costs per ton of CO_2 avoided. In addition, Brattle simulations illustrated that excluding new gas CCs from the emissions cap would introduce a discrepancy in the economics facing new and existing gas CCs that are identical in all respects other than their in-service dates. New CCs would earn greater profits in the energy market because they would be compensated as if they were entirely non-emitting plants.
- For a power industry association, conducted analysis of EPA's proposed rule for regulating CO_2 from existing sources under Section 111(d) of the Clean Air Act, focusing on potential economic impact to hydropower. Summarized key aspects of the rule, and assessed how the compliance options for states could differ from the BSER options in setting the target rates, and how states can utilize hydropower (existing or new) as a compliance option under the rule.
- For a western electric utility, evaluated the EPA's development of CO_2 rate targets in Arizona and assessed the reasonableness of projected pace and level of emission reductions. Conducted a detailed assessment of the assumptions and modeling approach in EPA's IPM simulations, and identified areas of improvements. Prepared a whitepaper to summarize the findings to be filed as part of the utility's comments to EPA.
- For an electric utility in the western U.S., conducted a study to assess reliability and supply-chain implications of compliance with EPA's Regional Haze Rule. Regional Haze Rule aims to reduce haze-forming pollution (primarily due to emissions of particulate matter and its precursors SO_2 and NO_x) that reduces visibility in parks and wilderness areas, especially in the Western U.S. We assessed the impact of outages at coal units to tie-in the environmental retrofit equipment on available resources to meet the utility's load obligations in the future. In addition, we compared the historical retrofits on coal units in the region against projected retrofits to comply with Regional Haze Rule.

- Co-authored a study commissioned by the Midwest Independent Transmission System Operator (MISO), evaluated the feasibility of the large number of simultaneous environmental retrofits and new generation that may be needed for coal plants to comply with the EPA's Mercury and Air Toxics Standards (MATS) rule. The study found that compliance with the MATS rule poses significant challenges. The study took into account the historical level of actual retrofits and new generation construction, typical timelines to complete various types of projects, potential bottlenecks in specialized types of labor, and the required planned outages in coal plants to install and test the environment control equipment.
- Co-authored studies that analyze the economics of retirement decisions for each coal plant operating in the United States under the proposed and emerging EPA air quality and water regulations, taking into account the predicted profitability and cost of replacement power for both regulated and unregulated plants. The regulations are expected to force coal plants to decide between retiring versus installing expensive control equipment to reduce emissions of SO_2, NOx, particulates, and hazardous air pollutants such as mercury, as well as cooling towers to reduce the use of cooling water.
- For a natural gas producer, analyzed the potential for change in natural gas demand as a result of the Waxman-Markey climate policy proposal. Using scenarios for new renewable capacity and price of natural gas relative to coal, analyzed effects of CO_2 prices on dispatch switching from coal-fired to gas-fired generation plants in various ISO regions, as well as on demand for gas in non-electric sectors.
- Assisted an electric utility in understanding the implications of the Waxman-Markey climate policy proposal on its renewable generation portfolio and its electricity sales to other regions. Our team identified opportunities and risks for specific renewable technologies due to provisions in the bill imposing renewable portfolio standards for electric utilities.
- For electric utility companies in the Eastern U.S., analyzed the potential effects of existing and developing environmental legislation and regulation on the existing generation fleet. The assignment included reviewing and summarizing the regulations by pollutant, identifying the specific generation plants that these regulations could affect, and estimating economics of retirement for each plant under a regulatory scenario.
- Conducted screening analyses for electric utilities to assess their exposure to allowance costs in the near term and long term due to recent cap and trade climate policy proposals. Under

alternative assumptions to comply with the regulations (from complete reliance on allowance purchases to reducing emissions to meet the economy-wide targets), estimated the potential cost of the policy net of free allowances under the proposal using various CO_2 price scenarios.

- For an electric utility, assisted in evaluating expected natural gas prices under potential CO_2 prices due to proposed federal climate policies in the U.S. The analysis included modeling of changes in demand for natural gas in electric and non-electric sectors as a result of potential CO_2 prices, as well as feedback effects due to dispatch switching from coal-fired generation plants to gas-fired generation plants in electric sector.
- Helped a large energy company evaluate the implications of several climate policy options on U.S. CO_2 emissions from electric and transportation sectors, and consumption and prices of electricity, natural gas, and coal. The analysis focused primarily on long-term implications for future generation capacity mix, and provided insights about the feedback effects between fuel prices, electricity prices, and electricity consumption.

WHOLESALE ELECTRIC MARKET ANALYSIS AND ASSET VALUATION

- For a group of market participants in Texas, managed a team to estimate the impacts of implementing marginal losses in the ERCOT market on system production costs, transmission losses, LMPs, load payments, and generator revenues. The Brattle team simulated the ERCOT power system using the PSO software, and calibrated the model to recent generation and load patterns. The study results were made public in a proceeding before the Texas Public Utility Commission.
- For a large group of generation owners and trade groups, conducted a study to estimate the above-market payments to certain merchant generation plants with 90-day fuel supply under the U.S. DOE's proposed payments. While the DOE's rationale for the proposed payments was to improve the resilient operations of the power system, the study concluded that 1) there is no evidence supporting the premise that 90 days of on-site fuel at individual power generating plants would improve the resilience of the grid in the regions where the rule would apply, and that 2) implementing the proposed rule would undermine core market principles and diminish some of the most important advantages of competitive wholesale power markets.
- For a developer of biogas power plant, submitted expert testimony on outlook on projected long-term wholesale power prices in Arizona. Reviewed forward market prices for near term

deliveries as of the execution date of a contract with the supplier of waste feedstock, and summarized the industry expectations for the timing of the need and cost to build new generation in the region.

- For a developer of solar PV generation plants, conducted research and analyses to identify potential opportunities for renewables to be offered to electric utilities as qualifying facilities (QFs) under the Public Utilities Regulatory Policies Act (PURPA). Summarized the states with the largest penetration of renewable QFs and most favorable contract/pricing terms, and presented the likely outlook on avoided cost rates by region.
- For an investment firm, evaluated the projected net margins from energy and capacity markets in the Northeast for a new gas-fired generation plant. Assessed the key market drivers and risk factors associated with the plant's future performance, and conducted analyses to assess the implications for the asset's market value.
- For an independent power producer, analyzed the market trends in California power markets and explore potential value drivers of the client's existing gas-fired combined-cycle plant in California. The Brattle team simulated the long-term wholesale energy prices in Southern California region, and developed a modeling tool to analyze the projected capacity payments for existing resources under the California's local resource adequacy construct.
- Assisted an electric utility in performing a valuation of a coal-fired unit. Managed the analysis to model the projected revenues from energy and capacity markets, as well as to project variable and fixed operating costs and environmental compliance costs in the future. Various market and regulatory scenarios are considered and presented to the client.
- For an investor, performed a valuation analysis of a potential new gas combustion turbine (CT) in Texas. Developed scenarios for future energy-only and capacity markets, estimated regional reserve margins under a few load growth scenarios. In addition to estimating annual energy margins using a virtual commitment and dispatch model, estimated the projected run-hours for the new CT.
- For an investor, co-authored a valuation analysis of a large gas-fired cogeneration facility in the Midwest. In addition to projecting energy and capacity prices in the region under the key uncertainties on gas prices, coal plant retirements, and renewable generation additions, the study analyzed the projected revenues under the existing long-term sale contracts to provide energy and steam.

- Co-lead of team to assist a municipal electric utility in the Midwest to sell a portion of its share of energy and capacity from a new coal plant. The Brattle team acted as the Sale Advisor to design the sale process, solicit bids, prepare informational documents, and evaluate the bids.
- For a Regional Transmission Organization (RTO) in the Midwest U.S., estimated the future costs and benefits from an electric utility joining that RTO as a member, compared to stand-alone and an alternative RTO membership. The analysis included impact on production cost savings, existing transmission constraints and interconnection capacities, wholesale trading activity, load diversity benefits, generation investment savings, and allocation of transmission costs and revenues.
- For a power plant developer, estimated the market potential for new wind, solar and gas peaking plants in the Eastern Interconnection. The Brattle team worked in close coordination with the client to develop and refine assumptions and scenarios on future fuel prices, capital costs of new plants, federal tax credits as well as federal climate policy. Economic potential for new generation alternatives is estimated by using Brattle's in-house simulation model Xpand, which optimizes plant dispatch as well as generation entry and retirements in order to meet future electric demand and reserve margin requirements.
- For an electric cooperative in the Midwest, conducted studies to evaluate the impact of planned new wind and gas combined-cycle units at alternative locations on the nodal energy prices and net revenues for generation fleet owned by the cooperative. Provided analytical support to assess likely allocations of auction revenue rights for hedging congestion.
- For a large merchant generation company in PJM, assessed the likely causes of high energy prices during the polar vortex events. Analyzed the impact of each driver on market prices, and conducted simulations to evaluate the likely market prices in the future under similar weather conditions and sensitivities for coal plant retirements, increased penetration of demand-resources, and expected gas prices.
- For a large coal company, assisted in designing and evaluating innovative coal supply contracts with power plants. The project team developed a customized tool to simulate the regional energy and capacity prices in the eastern power markets, and evaluated the profitability of various types of supply contracts from the perspective of the coal company and the power plant. In addition, the Brattle team identified coal-fired power plants that could be potential candidates to benefit from signing innovative coal supply contracts.

- For a group of electric utilities in the Midwest, led a team to assess the energy-related costs and benefits of joining an RTO. Using a nodal pricing simulation software, the team estimated the net costs to customers of the utilities with respect to energy, congestion, marginal losses, and allocation of financial transmission rights and loss refunds under each configuration (stand-alone and RTO membership).
- For clients in PJM, Dr. Celebi examined the variability of historical congestion patterns to help assess the reasonableness of the utilities' FTR/ARR acquisition strategies.
- Provided consulting services on the impact of moving into a Locational Marginal Price (LMP) market design for a client in WECC. In addition to quantifying the expected congestion cost exposure under LMP market design, examined the impacts of potential mitigating solutions on the cost exposure and on the client's ability to hedge these costs through acquisition of financial instruments.
- Estimated the economic benefits of a proposed power plant in California. The project included an analysis of benefits from reduced market-clearing prices, avoided/deferred transmission upgrades, and reliability improvements.
- For an independent power producer, assessed the competitive offer price for its planned gas-fired generation unit in the PJM capacity market. Under key scenarios reflecting uncertainty in market fundamentals and in reasonable modeling assumptions, estimated the net cost of new entry (Net CONE) for the generation plant using plant-specific cost and performance information supplemented by publicly available estimates for generic plants. The key modeling assumptions driving the range of results were the appropriate methodology to levelize overnight capital costs and the appropriate time period over which the costs of the generation plant would be recovered in the PJM markets.
- Assisted an energy company to understand the fundamentals of the PJM capacity markets to inform the company's bidding strategy in the capacity auctions. Conducted a training session to go over the auction clearing mechanism, simulation of the market-clearing prices and quantities and alternative methodologies to project future market supply curves.
- For an energy trading company in Western U.S., assessed the CAISO's historical calculations of nodal energy prices at specific locations. The focus of the assessment was to understand the impact of modeling differences between day-ahead energy markets and annual Congestion Revenue Rights (CRRs) auctions on the nodal energy prices at those locations. The findings of this assessment were used to support a complaint at FERC.

- For a transmission owner in Canada, assessed whether the proposed procedures to coordinate the Available Transmission Capacity (ATC) on its interfaces with neighboring systems are consistent with the FERC requirements and the practices of U.S. counterparts. ATC coordination is required under FERC Order 890 in order to ensure that ATCs are calculated in a consistent manner by transmission providers and transmission service is provided in a non-discriminatory manner.
- For a Regional Transmission Operator (RTO) in Eastern U.S., assisted in the preparation two expert reports regarding an alleged manipulation of market credit rules through its trading activity in the FTR markets. The analysis involved a review of the trading activity and an assessment of risks assumed by the trader through a review of historical congestion prices.
- Submitted a rebuttal and surrebuttal testimony jointly before the Pennsylvania Public Utilities Commission on the causes of an episode of high locational marginal prices (LMPs) experienced by a small electric utility in PJM wholesale energy markets. Using data on potential causes of high congestion and detailed market simulation modeling, identified several causes including increased virtual bidding activity, reduced transmission capability, and changes to physical characteristics of certain transmission assets.
- For an electric utility considering joining an RTO, managed transmission flow analyses of generation and load deliverability, as well as LMP market simulations to assess the effects of the company's move on prices in its service territory.
- Co-authored a report reviewing the results and the performance of the ISO-NE Forward Capacity Market (FCM) auctions conducted for the 2010/2011 and 2011/2012 commitment periods.
- Submitted affidavit at the Public Utilities Commission of Texas (PUCT) regarding a proposed rule to allocate costs of procuring replacement reserves to market participants in ERCOT.
- Analyzed the economic and network impacts of a utility signing renewable energy contracts with several potential renewable generation projects. Using market simulation tools such as MarketSymTM and PowerworldTM, simulated an entire reliability council to assess whether each of the potential renewable generation projects would cause additional transmission constraints, and estimated the impacts of these projects on LMPs across the region.
- Assisted an electric utility before the energy regulator in Quebec, Regie De L'Energie, involving third-party access to an electric transmission system owned and operated by another company.

- Assisted numerous clients in examining the potential for exercise of horizontal and vertical market power under FERC's market power tests as a result of asset acquisitions, mergers, and as part of periodical market-based rate (MBR) filings.
- Helped a client assess the potential liability and market impacts associated with offering the output of an out-of-service generation unit to the ISO-NE markets.
- Led the efforts to prepare a report assessing the implications of the Open Access Transmission Tariff (OATT) filed by Midwest ISO on market efficiency and gaming opportunities.
- Contributed to The Brattle Group's investigation of the California power crisis on issues involving physical or economic withholding and manipulative gaming strategies such as double-selling, circular scheduling, wheel-out, simulation of real-time energy, and ancillary services markets.
- Estimated the potential for the exercise of market power in a load pocket in the Northeast U.S. power markets. The study simulated strategic behavior in order to assess the price risk for a distribution company due to congested transmission facilities.

ENERGY LITIGATION

- In an international arbitration dispute involving a coal mine in South America, co-managed a team to support expert report on the economic damages associated with a change in royalty structure. The analysis included the impact of royalty terms on the incentives for increasing mine production and on royalty payments to the government, under base outlook and sensitivities for projected international coal prices, mine cost structure, and discount rates.
- In a coal bankruptcy case regarding the qualification of a coal supply contract under the safe harbor provisions in the U.S. Bankruptcy Code, assisted an electric utility to evaluate the effectiveness of a long-term coal supply agreement as a hedge against regional fuel and power prices, including alternative coal prices and the more volatile prices of natural gas and wholesale power.
- In a large litigation case before FERC, provided testimony on the economic burden imposed by the prices in two long-term contracts that California Department of Water Resources (CDWR) signed with Shell and Iberdrola during the California energy crisis. Estimated the "down the line" economic burden by comparing the payments under the contracts to prices in comparable contracts and market prices after the end of the dysfunction. Assessed whether

the contract prices could be explained by the expected future market fundamentals in the California power markets by using DAYZER market simulation software for the near-term and expected cost of installing and operating a new generation unit for the long-term.

- For estimating breach-of-contract damages, managed the team to support expert testimony in a high-profile international arbitration case. Brattle team built and ran simulation models to forecast power prices and GHG allowance prices in California and the rest of Western states through 2050, accounting for very short-term operational effects as well as long-term capacity expansion needs. The simulation models covered all of the states in the full Western Electricity Coordination Council (WECC) region to capture California's dependency on imports from other areas and changes in price and availability of these imports over time. The modeling team evaluated the impact of GHG policies, RPS policies, changes in load forecasts, changes in hydro conditions, and changes in natural gas prices over time on the power and GHG allowance prices. The simulation models were benchmarked against historical unit dispatch and near term power price forwards to replicate actual market operations and expectations. The Brattle team used the resulting range of power price forecasts under expected range of future market conditions to estimate damages, including an options framework to simulate plant operations and show the threshold conditions for economic shutdown.
- In a New Source Review (NSR) litigation case, analyzed whether the repairs conducted in several coal-fired generation plants should have been expected to result in significant increases in emissions of certain pollutants. The major disagreements were on the choice of baseline emissions and the level of expected impact from the repairs.
- In several NSR cases, estimated the amount of potential increases in emissions of SO_2 and NOx as a result of repairs and replacements of various equipment in coal-fired generation plants. The analyses focused on potential increases in emissions due to avoided outage hours or increased output due to improved relative efficiency of the plants compared to the rest of the generation facilities in the system.
- For a group of municipal electric utilities in Massachusetts buying energy from a generating facility under a long-term contract, assisted in evaluating their net benefits from requesting must-run operation of the facility relative to the operations chosen by the seller. The engagement also included a comparison of municipal utilities and investor-owned utilities with respect to their incentives under the Massachusetts Electric Restructuring Act to buy out their power purchase contracts.

- Helped a client in the Western U.S. in a litigation case involving allegations of market power and market dysfunction affecting the prices and other terms of various long-term electricity purchase and sale contracts.
- Managed several cases related to estimation of damages resulting from early termination of power contracts.

RETAIL ELECTRIC RATES - COST ESTIMATION AND RECOVERY

- For an investor in distributed gas-fired generation assets in Texas, conducted a study on future savings in transmission and distribution service costs, and potential market penetration of distributed energy resources. The Brattle team reviewed key aspects of the wholesale market structure that directly impact the long term stability of the transmission tariff rate, and identified potential risks and mitigating factors associated with possible changes to the design of the market.
- For a retail electric provider in ERCOT, analyzed the costs and savings in its contract with a large customer to provide various services.
- In a merger involving two electric companies in the Eastern U.S., analyzed the impacts of the merger on competition in retail electricity markets. Both companies owned electric distribution companies, transmission assets, generation resources, and retail electricity providers in several states. The analysis involved assessment of whether the increased market share in wholesale energy markets affects retail competition, number of suppliers in retail electricity markets, ease of entry and exit to provide electricity to retail customers directly or through Default Service (DS) procurements, and potential for abusing affiliate relationships with the electric distribution company to favor the retail electricity provider affiliate.
- For an association of suite meter providers in Canada, analyzed whether the incumbent electric utility has been cross-subsidizing the provision of suite meters to its residential customers at the expense of its other customers. The analysis involved a comparison of the estimated fully-allocated costs of providing suite meters to the net revenues from these customers under the regulated retail rates under alternative assumptions on the costs of meters and types of suite meter installations.

- Prepared a Marginal Cost Study for an integrated electric utility in an RTO-region in U.S. The study estimated the incremental costs to the utility of serving additional demand and customers by time period, sub-region, and customer class.

- For a large electric customer of a utility in Western U.S., assisted in evaluating the utility's proposed rate design. Specifically, provided an assessment of alternative methods to classify generation costs (as demand, energy, or customer-related) and to allocate the fixed costs among customer classes. The analysis also included an assessment of the treatment of the costs and revenues associated with off-system sales in determining the revenues to be recovered from various customer classes.

- For an electric customer in U.S., analyzed whether a proposed change in rates by the electric utility would result in just and reasonable rates for transmission-level and station-service customers. The resulting testimony assessed whether the proposed rates were consistent with fundamental principles of ratemaking such as cost causation and rate stability, and compared the proposed rate design to the rate options provided by utilities in other jurisdictions for transmission-level and station-service customers. The parties settled the case with reduced rates for the client based on the lower cost of serving transmission-level customers relative to distribution-level customers.

- For an electric utility planning to install smart meters and in-home displays in the Eastern U.S., assisted in estimating the likely benefits to retail customers and to the utility. The quantified benefits to the utility company mostly came from reduced costs of meter reading and outage managements, whereas the customer benefits came from reduced costs of energy, capacity, and carbon emissions as a result of reduced peak load and annual energy consumption.

- Co-managed a case regarding a Texas electric utility company auctioning off its generation assets in order to determine its stranded costs. The project team assessed whether the market value of the utility's jointly-owned generation assets was depressed due to the rights of first refusal (ROFR) provisions attached to these assets, and whether the utility company failed to take commercially reasonable steps to mitigate its stranded costs.

- Helped a client analyze the cost of providing ancillary services (reserves, regulation, voltage support, etc.) from its hydroelectric generation facilities. The analysis required special emphasis to deal with the implications of separating cost of energy and ancillary services on the electricity rates of different customer types.

ADDITIONAL EXPERIENCE

- Before joining The Brattle Group, Dr. Celebi worked as an economic consultant for London Economics Inc. He designed a simulation model of the wholesale power market in the market area served by the New York Independent System Operator (NYISO).
- Ph.D. thesis on the regulation of investment in reliability and capacity of power transmission networks. Dr. Celebi illustrated that the structure of incentives to provide transmission capacity under a particular reward mechanism changes drastically when transmission reliability is also a choice variable to the owner. He particularly found that the well-known result of under-investment in capacity does not necessarily hold in this new environment. Therefore, Dr. Celebi characterized the optimal regulation of a line owner under incomplete information using line reliability as another choice variable.
- Dr. Celebi taught Microeconomics and Macroeconomics for one year at Boston College. He has also worked as a Teaching Assistant for a graduate-level Game Theory course, and for a number of undergraduate level courses.
- Dr. Celebi also attended the Summer School in Economic Theory on Auctions and Market Design (Hebrew University).

ACADEMIC HONORS AND FELLOWSHIPS

- Summer dissertation award in 1999, Graduate School of Arts and Sciences, Boston College
- Summer dissertation award in 1998, H. Michael Mann Fund, Boston College
- Scholarship from Yasar Holding Company, 1991-1993
- Tuition scholarship and stipend from the Turkish Ministry of Education towards the completion of B.Sc. Degree in Industrial Engineering, 1988-1993

PUBLICATIONS

"New Technologies and Old Issues under PURPA", by Robert S. Mudge, Metin Celebi, Marc Chupka, and Peter Cahill, published in the February 2018 issue of Norton Rose Fulbright's Project Finance NewsWire, February 26, 2018.

"The Future of Cap-and-Trade Program in California: Will Low GHG Prices Last Forever?", by Yingxia Yang, Michael Hagerty, Ashley Palmarozzo, Hannah Sheffield, Metin Celebi, Marc Chupka, and Frank C. Graves, December 5, 2017.

"Comments on Expanding CES Eligibility to Existing Nuclear Units", by Onur Aydin, Metin Celebi, David Luke Oates, Tony Lee, and Kelly Oh, Prepared for NextEra Energy Resources, and presented to the Massachusetts Department of Environmental Protection in response to the proposed Clean Energy Standard-Existing (CES-E), November 30, 2017.

"The Future of the U.S. Coal Generation Fleet", by Metin Celebi, Marc Chupka, Dean M. Murphy, Samuel A. Newell, and Ira H. Shavel, published in the Fall 2017 newsletter for the ABA Antitrust Section, Transportation and Energy Industries Committee, November 30, 2017.

"Evaluation of the DOE's Proposed Grid Resiliency Pricing Rule", by Metin Celebi, Judy Chang, Marc Chupka, Samuel A. Newell, and Ira H. Shavel, prepared for NextEra Energy, Inc., October 26, 2017.

"Impacts of Marginal Loss Implementation in ERCOT", by Metin Celebi, Toshiki Bruce Tsuchida, Rebecca Carroll, Colin McIntyre, and Ariel Kaluzhny, prepared for Ad Hoc Group, including Vistra Energy, The Wind Coalition, and First Solar, October 11, 2017.

"Nuclear Retirement Effects on CO_2 Emissions: Preserving a Critical Clean Resource", by Metin Celebi, Marc Chupka, Frank Graves, Dean Murphy, and Ioanna Karkatsouli, December 2016.

"Covering New Gas-Fired Combined Cycle Plants under the Clean Power Plan: Implications for Economic Efficiency and Wholesale Electricity Markets", by Judy Chang, Kathleen Spees, Metin Celebi, and Tony Lee, November 2016.

"The Clean Power Plan: Focus on Implementation and Compliance", by Marc Chupka, Metin Celebi, Judy Chang, Ira H. Shavel, Kathleen Spees, Jürgen Weiss, Pearl Donohoo-Vallett, Michael Hagerty, and Michael A. Kline, Brattle Policy Brief, January 2016.

"EPA's Proposed Clean Power Plan: Implications for States and the Electricity Industry," by Metin Celebi, Kathleen Spees, J. Michael Hagerty, Samuel A. Newell, Dean Murphy, Marc Chupka, Jürgen Weiss, Judy Chang, and Ira Shavel, Brattle Policy Brief, June 2014.

"Coal Plant Retirements: Feedback Effects on Wholesale Electricity Prices", by Onur Aydin, Frank C. Graves, and Metin Celebi, November 2013.

METIN CELEBI

"Potential Coal Plant Retirements: 2012 Update," by Metin Celebi, Frank C. Graves, and Charles Russell, The Brattle Group, Inc., October 2012.

"Supply Chain and Outage Analysis of MISO Coal Retrofits for MATS," with Kathleen Spees, Quincy Liao, and Steve Eisenhart, May 2012.

"State Regulatory Hurdles to Utility Environmental Compliance," with Philip Q Hanser and Bin Zhou, Electricity Journal, April 2012.

"Potential Coal Plant Retirements in U.S. and Impact on Gas Demand," presented at CERI Conference in Calgary, Alberta, February 27, 2012.

"Decision Complexities in Utility Resource Planning and Environmental Compliance Investment", with Frank Graves, chapter in EPRI report "The Market Backdrop to U.S. Power Generation Coal Technology Goal-Setting and Learning", September 2011.

"Marginal Cost Analysis in Evolving Power Markets: The Foundation of Innovative Pricing, Energy Efficiency Programs, and Net Metering Rates", with Philip Q Hanser, Brattle Group Energy Newsletter, Issue 2, 2010.

"Virtual Bidding: The Good, the Bad, and the Ugly – Experience of RTOs with Virtual Bidding and Implications for Market Participants' Hedging Congestion Costs," with Attila Hajos and Philip Q Hanser, Electricity Journal, June 2010.

"Can the U.S. Congressional Ethanol Mandate be Met?", with Evan Cohen, Michael I. Cragg, David Hutchings, and Minal Shankar, Brattle Group Discussion Paper, May 2010.

"Prospects for Natural Gas Under Climate Policy Legislation: Will There be a Boom in Gas Demand?" with Steven H. Levine, Frank C. Graves, Brattle Group Discussion Paper, March 2010.

"Internal Market Monitoring Unit Review of the Forward capacity Market Auction Results and Design Elements," with Dave Laplante, Hung-po Chao, Sam Newell, and Attila Hajos, June 5, 2009 (filed at FERC by ISO-NE on the same date).

"CO_2 Price Volatility: Consequences and Cures," with Frank Graves, Brattle Group Discussion Paper, January 2009.

A Lexicon entry for "A Theory of Incentives in Procurement and Regulation - Laffont&Tirole" in Lexikon der Okonomischen Werke, with Richard Arnott, (2006).

Contributing author of the Energy Bar Association Antitrust Committee's Report on 2005 Antitrust Development.

"The CAISO's Physical Validation Settlement Service: A Useful Tool for All LMP-Based Markets," with Philip Q. Hanser, Jared S. des Rosiers, and Joseph B. Wharton, Electricity Journal, October 2005.

"The Design of Tests for Horizontal Market Power in Market-Based Rate Proceedings," with James Bohn and Philip Hanser, Electricity Journal, May 2002.

"Financial Transmission Rights: Implementation Issues," with Philip Hanser, Working Paper, February 2002.

"An Analysis of Incentives and Regulation in Providing Capacity and Reliability in Power Transmission Networks," Unpublished Ph.D. Thesis, Boston College, September 2000.

PRESENTATIONS

"Future of Coal: Clean Power Plan, Market Drivers, and Other Regulations", by Metin Celebi, presented at the American Coal Ash Association's (ACAA) 2017 Winter Membership Meeting, January 25, 2017.

"CO_2 Regulations and Coal", by Metin Celebi, presented at Energy Bar Association's (EBA) Energizer, "Ongoing Climate Imperative", November 10, 2016.

"Update on Clean Imperative and Sectoral Responses in the US Power Industry", by Robert S. Mudge, Metin Celebi, Susan Nickey, Allyson Umberger Browne, and Elias B. Hinckley, presented at the American Bar Association (ABA) Business Law Section's Annual Meeting, September 8, 2016.

"The Clean Power Plan: Retirements and Reliability", by Metin Celebi, presented at the Wisconsin Energy Institute 2015 Energy Summit, Madison, WI, October 2015.

"The Clean Power Plan: Retirements and Reliability", by Metin Celebi, Michael Hagerty, Yingxia Yang, and Nicole Irwin, EUCI Conference, Houston, TX, April 1, 2015.

"Hydropower and the EPA Section 111(d) Proposal", by Marc Chupka, Metin Celebi, and Kathleen Spees, Presented at the National Hydropower Association, August 12, 2014.

"Coal Plant Retirements and Market Impacts," presented at the Wärtsilä Flexible Power Symposium, February 5, 2014.

"U.S. Coal Plant Retirements: Outlook and Implications," presented at the Coaltrans West Coast Conference, Las Vegas, June 14, 2013.

"U.S. Coal Plant Retirements: Outlook and Implications," by Metin Celebi, The Brattle Group, Inc., presented at the West LegalEd Center CLE Webcast, January 24, 2013.

"Environmental Retrofits: Costs and Supply Chain Constraints," presented at MISO Annual Stakeholders' Meeting in Indiana, June 2012.

"Potential Coal Plant Retirements and Retrofits Under Emerging Environmental Regulations," presented during the annual meeting of Minnesota Rural Electric Association (MREA), August 10, 2011.

"Potential Coal Plant Retirements in ERCOT Under Emerging Environmental Regulations," with Frank Graves, presented before Public Utility Commission of Texas, at Workshop on Potential Environmental Regulations and Resource Adequacy, June 22, 2011.

"The Regulatory Landscape for Coal-Fired Power: EPA Rules and Implications," with Frank Graves and Marc Chupka, presented at EUCI Conference in Miami, Florida, January 24, 2011.

"Potential Coal Plant Retirements under Emerging Environmental Regulations," with Frank Graves, Gunjan Bathla, and Lucas Bressan, presented at EUCI Webinar on December 8, 2010.

"Financial Instruments in Power Markets: Virtual Bids and FTRs," with Attila Hajos and Philip Q Hanser, presented at EUCI Conference in Washington, DC, July 19, 2010.

"Marginal Cost Studies in Ratemaking and Implications of Federal Climate Policy," presented by Dr. Metin Celebi as an invited speaker at Southeastern Electric Exchange Rates and Regulation Section Meeting, Charleston, South Carolina, October 28, 2009.

"CO_2 Price Volatility Delays Clean Generation Investment," presented by Dr. Metin Celebi at Law Seminars International's Renewable Energy in New England conference as an invited speaker, Boston, June 25, 2009.

"What to Expect from Electric Power and Transport Sectors in Response to U.S. Climate Policy," presented by Dr. Metin Celebi at Rutgers University Center for Research in Regulated Industries, January 18, 2008.

"Financial Transmission Rights: Necessary or Burdensome?," by Dr. Metin Celebi and Philip Q Hanser, IAEE Conference, Potsdam, June 7, 2006.

"Regulation of Transmission Investment and Reliability in Power Networks," Presented to the METU International Conference in Economics V, September 2001, Ankara, Turkey.

TESTIMONY

Before the Superior Court of the State of Arizona, Expert Report on behalf of Vieste SPE, LLC and Vieste Energy LLC re: projected long-term wholesale power prices in Arizona, January 30, 2017 and February 21, 2017.

Before Federal Energy Regulatory Commission, Prepared Direct Testimony on Behalf of the California Parties re: economic burden imposed by the prices in two long-term contracts that California Department of Water Resources (CDWR) signed with Shell and Iberdrola during the California energy crisis.

Before the Public Service Commission of Wisconsin, Pre-filed Rebuttal and Sursurrebuttal Testimony on behalf of Wisconsin Public Service Corporation re: the impacts of pending coal plant retirements and environmental retrofits on energy and capacity prices in the MISO region, December 14, 2012 and January 11, 2013.

Before the District of Columbia Office of Tax and Revenue, Affidavit on behalf of Pepco Energy Services re: categorization of electricity as a tangible property versus a service for determining the eligibility of electricity sales for exemption from sales tax, July 15, 2011.

Before the Pennsylvania Public Utilities Commission, Docket No. P-2008-2020257, Rebuttal and Surrebuttal Testimony on behalf of Pennsylvania Electric Company re: causes and pricing of transmission congestion in Wellsboro area in PJM, January 16, 2009, March 10, 2009 (with P. Hanser).

Before the Public Utilities Commission of Texas, Docket 33416, Affidavit supporting Constellation New Energy's Request for Expedited Hearing re: allocation of replacement reserve costs in ERCOT, November 8, 2006.

Exhibit Celebi-2 – Report on Economic Viability of Station Two

Economic Viability of Station Two

PRESENTED TO

Big Rivers Electric Corporation

PREPARED BY

Metin Celebi

May 1, 2018

THE Brattle GROUP

Exhibit Celebi-2

Agenda

Objective and Approach

Summary Results

Actual Plant Operations in 2017 and Model Calibration

Projected Dispatch and Cashflows under Base Case

Scenarios

Conclusions

Objective and Approach

Objective: Determine whether Station Two is capable of normal, continuous, reliable operation for the economically competitive production of electricity in the MISO wholesale power market.*

Approach:

- Calibrate the modeled commitment and dispatch of each unit at the plant against actual plant operations in 2017;
- Estimate the economic dispatch of the units for the period 2019-2035 under several market outlooks;
- Estimate annual gross margins for the plant by comparing the projected variable and fixed costs of the plant against projected market revenues from selling energy and capacity in MISO;
- Assess the timing of economic retirement based on annual and present value of gross margins for the plant.
  - Analyze a sensitivity for economic viability of Unit 1 (with Unit 2 retirement by the end of 2018)

* Per the Amendments to Contracts Among City of Henderson, Kentucky, City of Henderson Utility Commission and Big Rivers Electric Corporation, dated July 15, 1998 (page 2), "[t]he terms of all the Contracts except the Joint Facilities Agreement shall be extended for the operating life of Station Two, the operating life of which shall be considered to continue for so long as Unit 1 and Unit 2, or either of them, is operated, or is capable of normal, continuous, reliable operation for the economically competitive production of electricity, temporary outages excepted".

Exhibit Celebi-2

Summary Results

Retirement Economics for Station Two
Base Case and Scenarios

Station Two is not capable of normal, continuous, reliable operation for the economically competitive production of electricity in the MISO wholesale power market under the Base Case and four scenarios we evaluated.

- Operating the plant until the end of 2035 would result in substantially larger negative gross margins (i.e., larger losses) compared to retirement at the end of 2018.
- Assuming a lower discount rate (5%) would increase the attractiveness of early retirement.

Net Revenue* Impact of Delaying Retirement from End of 2018 to 2035 ($millions)

Scenario	Discount Rate 8%	5%
Base	[redacted]	
Low Gas		
High Gas		
Carbon Pricing		
Additional Revenue for Baseload		

(*) Dollars shown in present value as of the beginning of 2018.

Exhibit Celebi-2

Conclusions for Station Two
(with 8% Discount Rate)

Operating Station Two until the end of 2035 reduces the PV of net revenues compared to retiring at the end of 2018 by about [redacted] million across the scenarios we analyzed.

STATION TWO ECONOMIC VIABILITY* DURING 2019-2035

			Scenarios				
	Description	Units	Base Case	1 - Low Gas Prices	2 - High Gas Prices	3 - Carbon Pricing	4 - Additional Revenue for Baseload
[1]	Annual Average Capacity Factor	%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[2]	Market Revenues for Station Two		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[3]	Energy	$ m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[4]	Capacity	$ m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[5]	Total Market Revenues	$ m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Less:		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[6]	Avoidable Costs of Station Two		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[7]	Fuel	$ m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[8]	Variable O&M	$ m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[9]	Allowance Costs	$ m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[10]	Fixed O&M	$ m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[11]	Ongoing Capex	$ m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[12]	Deferred Decomm from 2018 to 2035	$ m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[13]	Total Costs	$ m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[14]	**Net Revenues [5] - [13]**	**$ m**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

(*) Dollars shown in present value as of the beginning of 2018, @ 8% discount rate.

Conclusions for Station Two
(with 5% Discount Rate)

Operating Station Two until the end of 2035 reduces the PV of net revenues compared to retiring at the end of 2018 by about [redacted] million across the scenarios we analyzed.

STATION TWO ECONOMIC VIABILITY* DURING 2019-2035

			Scenarios				
	Description	Units	Base Case	1 - Low Gas Prices	2 - High Gas Prices	3 - Carbon Pricing	4 - Additional Revenue for Baseload
[1]	Annual Average Capacity Factor	%	[redacted]				
[2]	Market Revenues for Station Two						
[3]	Energy	$ m					
[4]	Capacity	$ m					
[5]	Total Market Revenues	$ m					
	Less:						
[6]	Avoidable Costs of Station Two						
[7]	Fuel	$ m					
[8]	Variable O&M	$ m					
[9]	Allowance Costs	$ m					
[10]	Fixed O&M	$ m					
[11]	Ongoing Capex	$ m					
[12]	Deferred Decomm from 2018 to 2035	$ m					
[13]	Total Costs	$ m					
[14]	**Net Revenues [5] - [13]**	**$ m**					

(*) Dollars shown in present value as of the beginning of 2018, @ 5% discount rate.

Retirement Economics for Unit 1

Base Case and Scenarios

Operating Unit 1 until the end of 2035 while retiring Unit 2 at the end of 2018 will also not render Station Two capable of normal, continuous, reliable operation for the economically competitive production of electricity.

- Operating Unit 1 until the end of 2035 would result in substantially larger negative gross margins (i.e., larger losses) compared to retirement at the end of 2018.
- Assuming a lower discount rate (5%) would increase the attractiveness of early retirement.

Net Revenue* Impact of Delaying Retirement from 2018 to 2035 ($millions)

	Discount Rate	
Scenario	**8%**	**5%**
Base	[redacted]	
Low Gas		
High Gas		
Carbon Pricing		
Additional Revenue for Baseload		

(*) Dollars shown in present value as of the beginning of 2018.

Note that the net revenue impacts of delaying retirement of Unit 1 are disproportionately larger (i.e., more than half) compared to the Station Two results shown on slide 5. This is due to an increase in fixed costs per kW for Unit 1 if Unit 2 retires at the end of 2018.

Exhibit Celebi-2

Conclusions for Unit 1
(with 8% Discount Rate)

Retiring Unit 2 at the end of 2018 and continuing to operate Unit 1 until 2035 results in [redacted] million losses, compared to retiring both units at the end of 2018.

UNIT 1 ECONOMIC VIABILITY* DURING 2019-2035

			Scenarios				
	Description	Units	Base Case	1 - Low Gas Prices	2 - High Gas Prices	3 - Carbon Pricing	4 - Additional Revenue for Baseload
[1]	Annual Average Capacity Factor	%	[redacted]				
[2]	Market Revenues for Station Two						
[3]	Energy	$ m					
[4]	Capacity	$ m					
[5]	Total Market Revenues	$ m					
	Less:						
[6]	Avoidable Costs of Station Two						
[7]	Fuel	$ m					
[8]	Variable O&M	$ m					
[9]	Allowance Costs	$ m					
[10]	Fixed O&M	$ m					
[11]	Ongoing Capex	$ m					
[12]	Deferred Decomm from 2018 to 2035	$ m					
[13]	Total Costs	$ m					
[14]	**Net Revenues [5] - [13]**	**$ m**					

(*) Dollars shown in present value as of the beginning of 2018, @ 8% discount rate.

Exhibit Celebi-2

Conclusions for Unit 1
(with 5% Discount Rate)

Retiring Unit 2 at the end of 2018 and continuing to operate Unit 1 until 2035 results in [redacted] million losses, compared to retiring both units at the end of 2018.

UNIT 1 ECONOMIC VIABILITY* DURING 2019-2035

	Description	Units	Scenarios: Base Case	1 - Low Gas Prices	2 - High Gas Prices	3 - Carbon Pricing	4 - Additional Revenue for Baseload
[1]	Annual Average Capacity Factor	%	[redacted]				
[2]	Market Revenues for Station Two						
[3]	Energy	$ m					
[4]	Capacity	$ m					
[5]	Total Market Revenues	$ m					
	Less:						
[6]	Avoidable Costs of Station Two						
[7]	Fuel	$ m					
[8]	Variable O&M	$ m					
[9]	Allowance Costs	$ m					
[10]	Fixed O&M	$ m					
[11]	Ongoing Capex	$ m					
[12]	Deferred Decomm from 2018 to 2035	$ m					
[13]	Total Costs	$ m					
[14]	**Net Revenues [5] - [13]**	**$ m**					

(*) Dollars shown in present value as of the beginning of 2018, @ 5% discount rate.

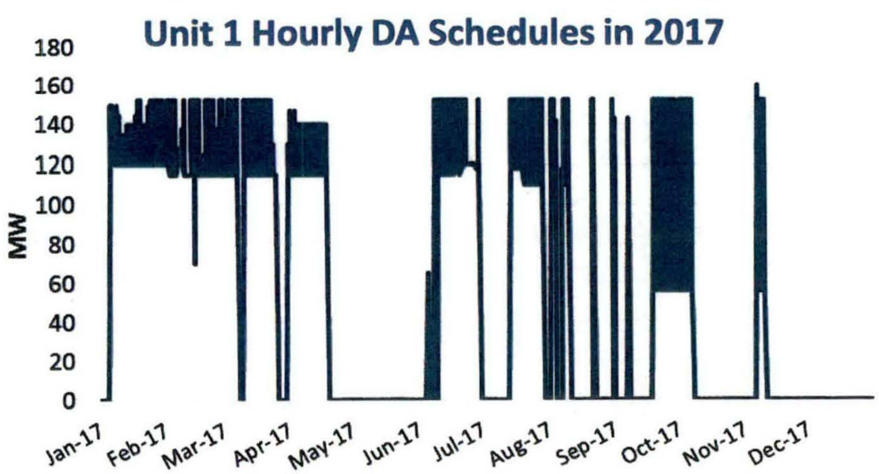
Exhibit Celebi-2

Actual Plant Operations in 2017 and Model Calibration

Actual Plant Operations in 2017

- Both units operated at low capacity factors (38% for U1, 51% for U2) and experienced forced outages (18% for U1, 11% for U2)
- Generation was about 15 MW higher for Unit 1 and 19 MW for Unit 2 on average during on-peak than off-peak.
- The units operated as must-run (combined output at least 235 MW) until summer, then one unit switched to economic commitment in late July, and both units switched to economic commitment at 56 MW Min Load per unit starting in early October.
- Realized DA LMPs at the unit nodes was about $29/MWh, compared to plant variable cost of $34/MWh.

	DA Generation			DA Capacity Factor			Outages			
	Average	On Peak	Off Peak	Average	On Peak	Off Peak	Planned		Forced	
	(MW)			(%)			(Hours)	(%)	(Hours)	(%)
Unit 1	57.7	65.3	51.1	38%	43%	33%	1,030	12%	1,548	18%
Unit 2	81.9	91.9	73.2	51%	58%	46%	0	0%	942	11%



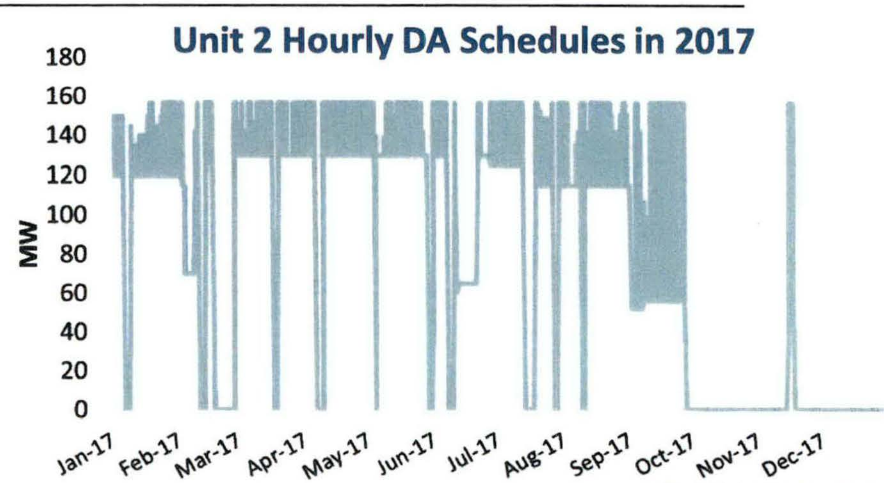


Exhibit Celebi-2

Actual Cashflows in 2017

The plant incurred negative energy and gross margins in 2017.

- Annual energy margin: [redacted] (energy revenues – variable costs)
- Annual gross margin: [redacted] (energy margin + capacity revenue – fixed O&M and CapEx costs)

2017 Actual Cashflows

		$ Millions	$/MWh
Variable Costs	[1]	[redacted]	[redacted]
Energy Revenues	[2]	[redacted]	[redacted]
Energy Margin	[3]	[redacted]	[redacted]
Fixed O&M and CapEx Costs	[4]	[redacted]	[redacted]
Capacity Revenues	[5]	[redacted]	[redacted]
Gross Margin	[6]	[redacted]	[redacted]

Source: BREC data
Notes:
[3] = [2] – [1]
[6] = [3] + [5] – [4]

Exhibit Celebi-2

Key Modeling Assumptions for 2017

Energy prices

- Actual DA LMPs at unit buses: $27.29/MWh average, hourly prices in the range of $11-$111/MWh

Fuel prices

- Delivered coal: [redacted]
- Fuel oil: [redacted]

Plant parameters

- Inc heat rates (btu): These are used in dispatch
  - Unit 1: [redacted]
  - Unit 2: [redacted]
- Avg heat rates (btu): These are used to calculate cashflows
  - Unit 1: [redacted]
  - Unit 2: [redacted]
- Variable O&M: [redacted]
- Start-up costs: [redacted]
- Min Up Time: [redacted] Min Down Time: [redacted]
- Mill cycle fuel oil use (from crossing [redacted]: [redacted]

Outages (actual planned and forced)

- Unit 1: [redacted] Unit 2: [redacted]

Exhibit Celebi-2

Key Modeling Assumptions for 2017 (cont'd)

Commitment and Dispatch

- Optimize against hourly DA LMPs (perfect foresight)
- Commitment (turn on/off) based on heuristic algorithm with average dispatch costs
  - Pass 1: no intertemporal constraints
  - Pass 2: eliminate unprofitable turn-offs in each cycle (considering start-up costs)
  - Pass 3: eliminate unprofitable turn-ons in each cycle (considering start-up costs)
  - Pass 4: enforce Min Up time constraint
  - Pass 5: schedule week(s) of planned outage based on energy margins
    - For 2017: adopted actual outages, and enforced 120 MW must-run for each unit through August
    - Adjusted dispatch to reduce mill cycle costs from switching the 110 MW threshold
- Dispatch between min load and max capacity based on comparison of hourly LMP vs. incremental dispatch cost

Model Results for 2017

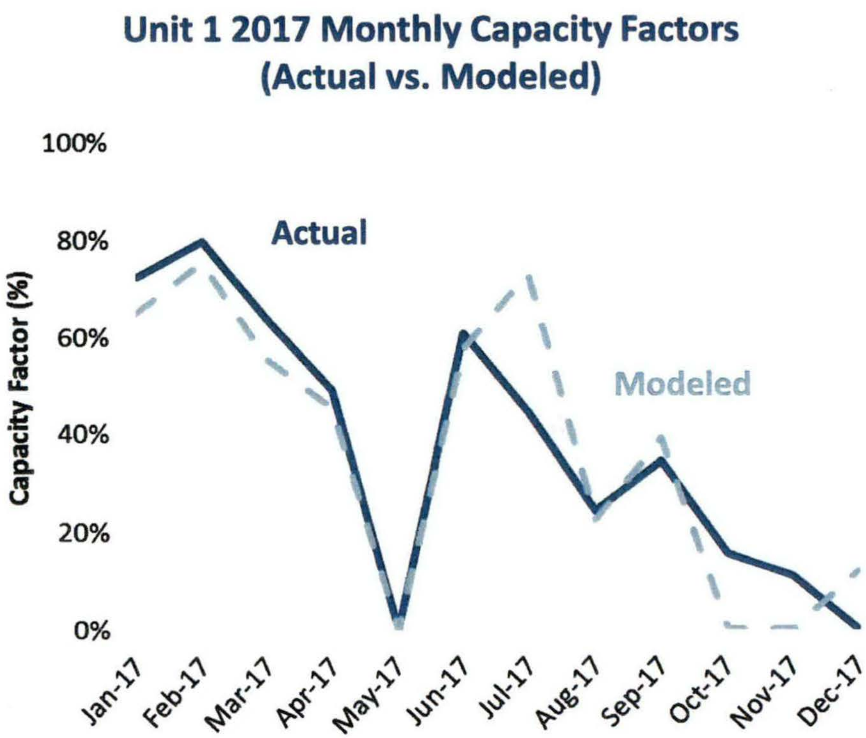
Modeled results for Station Two in 2017 are similar to the actual day-ahead (DA) generation schedules and gross margins in 2017.

		Actual DA		Modeled		Actual DA - Modeled	
		HMP1	HMP2	HMP1	HMP2	HMP1	HMP2
Generation	MWh	[redacted]					
Capacity Factor	%						
Total Variable Costs	$ millions						
	$/MWh						
Energy Revenues	$ millions						
	$/MWh						
Energy Margins	$ millions						
	$/MWh						
Fixed O&M and Capex	$ millions						
	$/kW-yr						
Capacity Revenues	$ millions						
	$/kW-yr						
Gross Margins	$ millions						
	$/kW-yr						

Exhibit Celebi-2

Model Results for 2017 (cont'd)

Modeled capacity factors are similar to Station Two's actual day-ahead dispatch, and sharply decreased after August 2017 when both units began to be economically committed and dispatched by MISO.



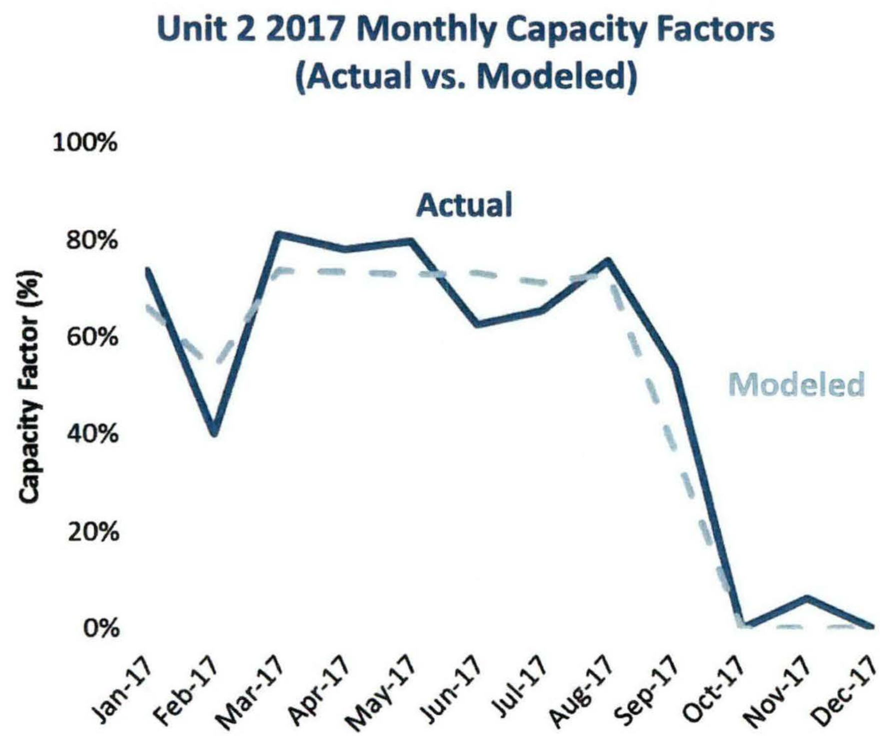


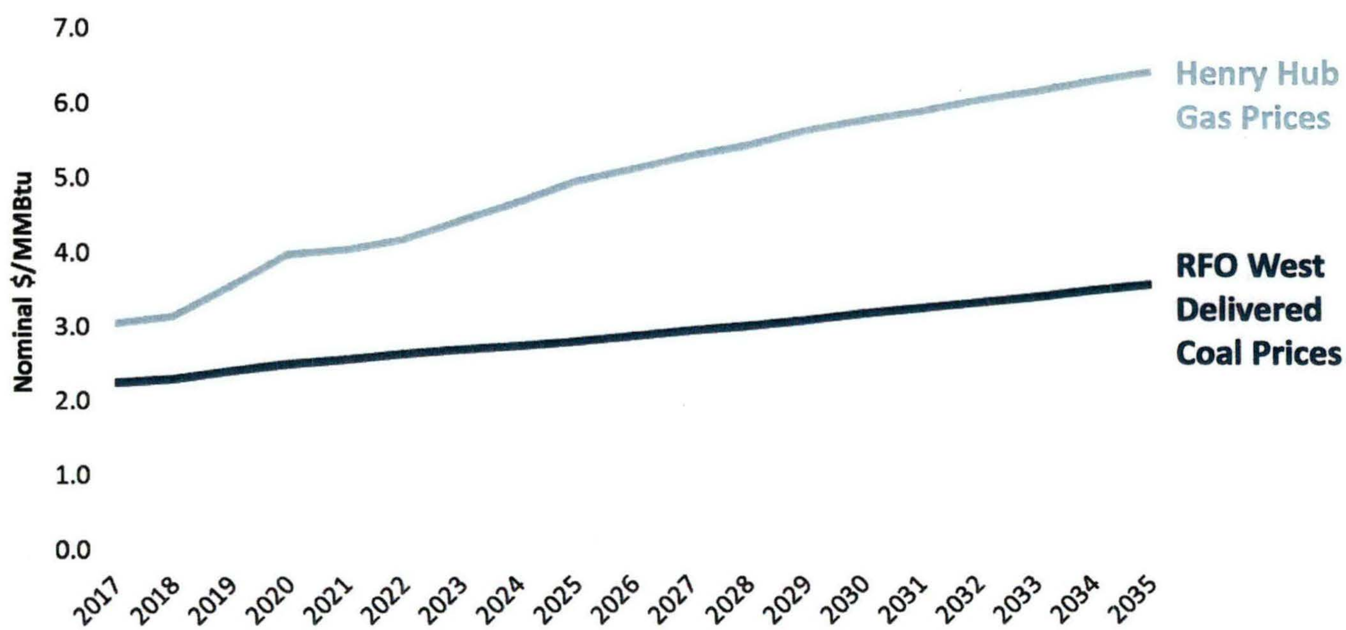
Exhibit Celebi-2

Projected Dispatch and Cashflows under Base Case

Key Modeling Assumptions for 2019-2035
Regional Fuel Prices

Adopted EIA's Annual Energy Outlook (AEO) 2018 Reference Case projections for Henry Hub gas prices and RFO West delivered coal prices.

AEO 2018 Fuel Price Projections



Source: EIA AEO2018.

Exhibit Celebi-2

Key Modeling Assumptions for 2019-2035
Emission Allowance Prices

CO_2 prices

- Assumed to be zero in the MISO region during the study period in the Base Case scenario.

SO_2 prices

- \$2.13/tonne based on current CSAPR Region 1 SO_2 prices, assumed to remain same during the study period.

NOx prices

- Annual NOx: \$2/tonne based on current CSAPR NOx prices, assumed to remain the same during the study period.
- Seasonal (summer) NOx: \$162.5/tonne based on current CSAPR Seasonal NOx prices, assumed to remain the same during the study period.

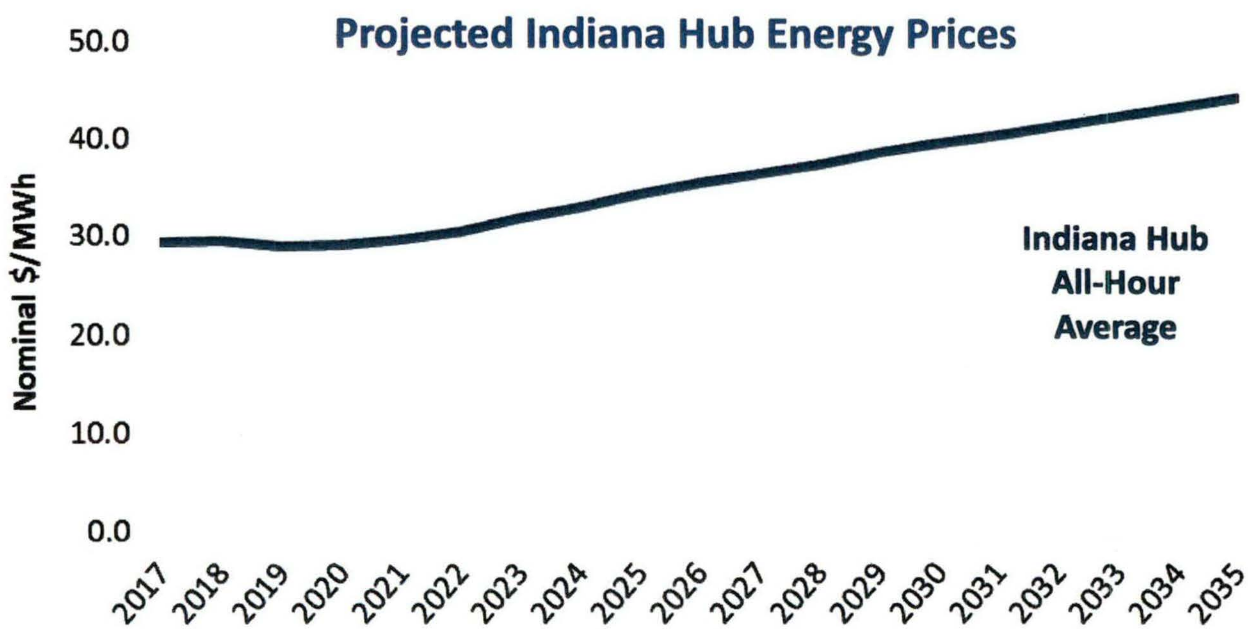
Exhibit Celebi-2

Key Modeling Assumptions for 2019-2035
Energy Prices

Projected hourly DA LMPs at the unit buses for future years by growing the LMPs in each hour in 2017 by the projected growth rate in Indiana Hub all-hour average energy prices.

Estimated future Indiana Hub energy prices as follows:

- 2018-2020: Forwards from averages during trading dates April 9 through April 13, 2018
- 2021-2035: Average growth rates of and Henry Hub and regional coal prices relative to 2020 are applied to 2020 forward energy prices



Source: Hourly DA LMPs and Power Forwards from SNL, and Brattle estimates after 2020.

Exhibit Celebi-2

Key Modeling Assumptions for 2019-2035
Zone 6 Capacity Prices

Estimated capacity prices in Zone 6 by using supply/demand outlook and offer price curve from the MISO capacity auction (PRA 2017/18).

- Assumed interzonal capacity limits are not binding, i.e., no price separation between Zone 6 and unconstrained MISO zonal prices.
- Adjusted the MISO capacity requirements in the PRA 2017/18 auction (135 GW) for future years by the growth in MISO's recent forecast of peak load (plus reserve margin)
- Added announced new generation (excluding "feasibility" and "proposed" status) to the MISO offer curve at zero price.
- Removed capacity of announced retirements from the MISO offer curve.
- Added generic new capacity in 100 MW increments as a price taker since regulated utilities would start building new capacity a few years before the MISO auction is conducted.
- Estimated the capacity price in each future year as the intersection of MISO offer curve and the MISO capacity requirement.

Capacity Price

Year	$/MW-day	$/kW-year
2017	1.50	0.55
2019	15.00	5.48

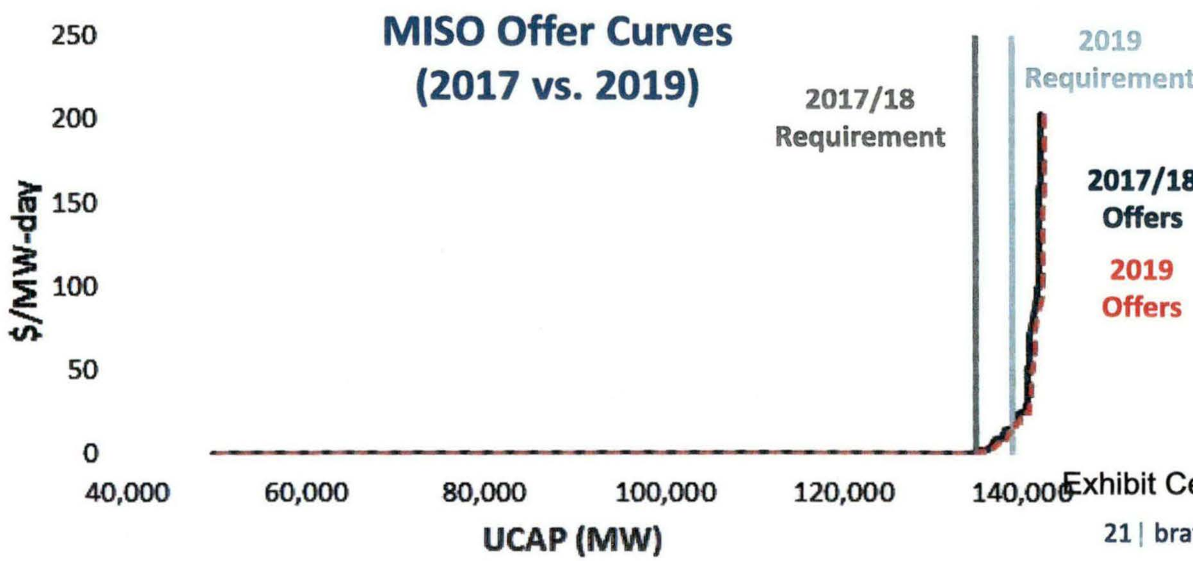


Exhibit Celebi-2

Key Modeling Assumptions for 2019-2035
Zone 6 Capacity Prices (cont'd)

Cumulative announced retirements start exceeding planned new generation in 2022, and load growth increases the need for additional capacity procurement.

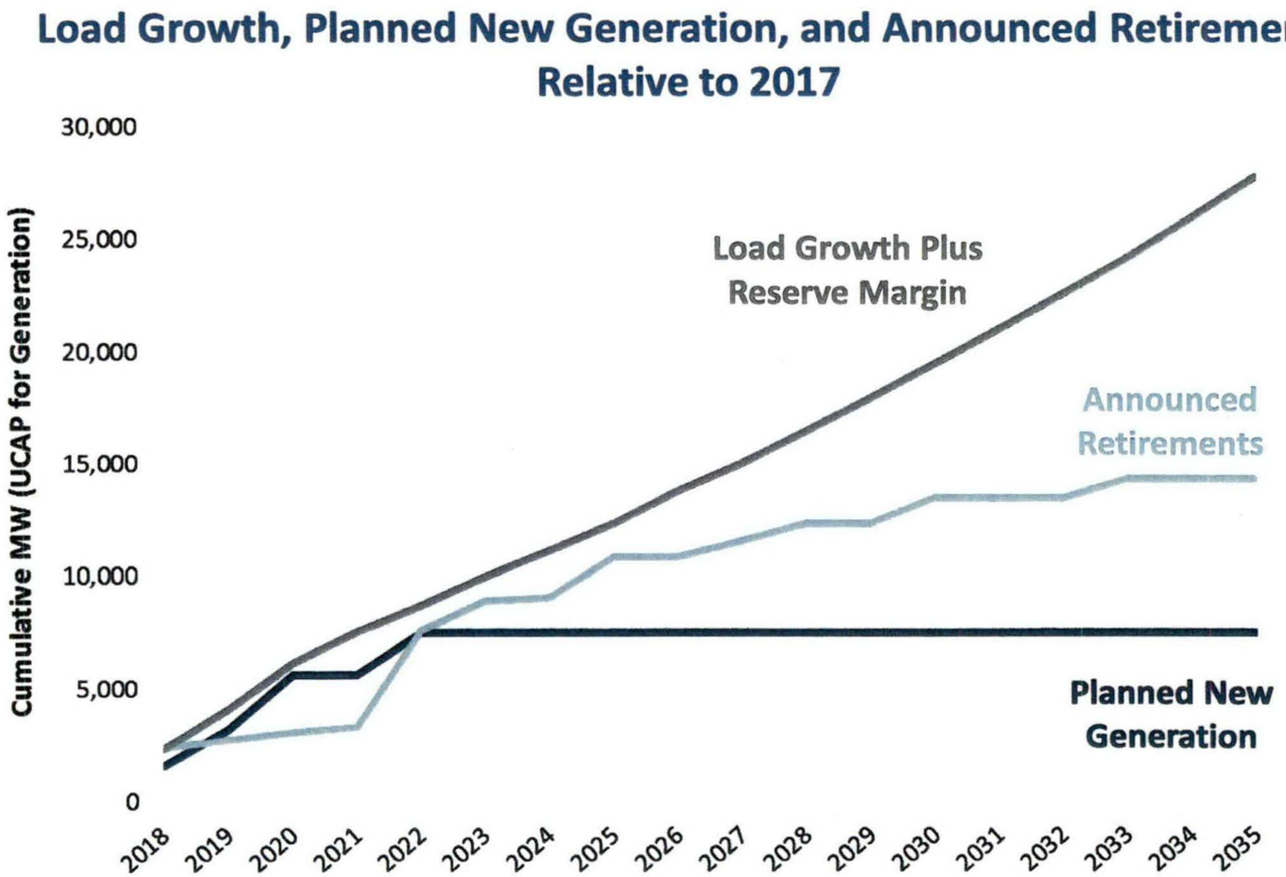


Exhibit Celebi-2

Key Modeling Assumptions for 2019-2035
Zone 6 Capacity Prices (cont'd)

Capacity prices are estimated to rise gradually to $10/kW-yr by 2021 as the excess capacity decreases due to load growth and retirements, then stay in the range of $60-75/kW-yr after that.

- The quick ramp-up in 2022 is due to 4 GW of planned retirements in that year.
- Price variation after 2023 is due to the assumed lumpiness of incremental new generation additions.

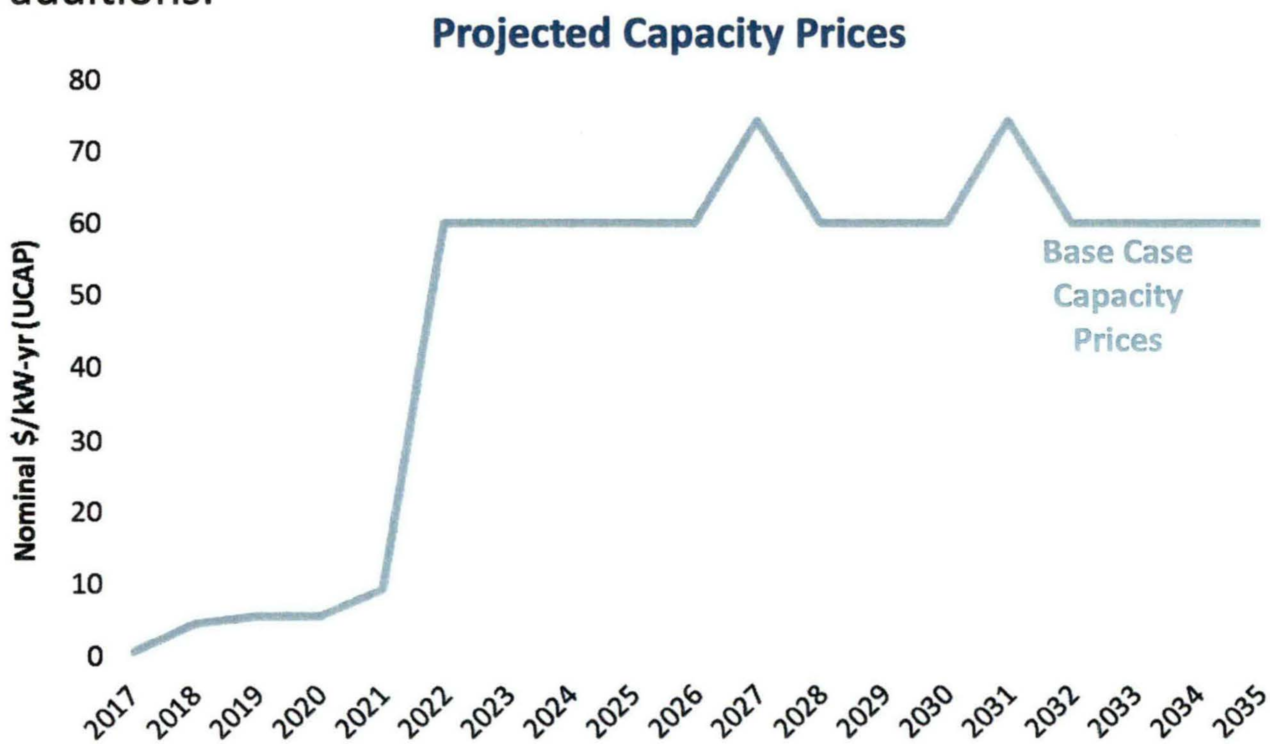


Exhibit Celebi-2

Key Modeling Assumptions for 2019-2035
Station Two Costs and Parameters

Delivered fuel prices

[redacted]

Plant parameters

[redacted]

Outages

[redacted]

Exhibit Celebi-2

Key Modeling Assumptions for 2019-2035
Station Two Costs and Parameters (cont'd)

Commitment and Dispatch

- Optimize against hourly DA LMPs (perfect foresight)
- Commitment (turn on/off) based on heuristic algorithm with average dispatch cost curves
  - Pass 1: no intertemporal constraints
  - Pass 2: eliminate unprofitable turn-offs in each cycle (considering start-up costs)
  - Pass 3: eliminate unprofitable turn-ons in each cycle (considering start-up costs)
  - Pass 4: enforce Min Up time constraint
  - Pass 5: schedule week(s) of planned outage based on energy margins
- Dispatch between min load and max capacity based on comparison of hourly LMP vs. incremental dispatch cost
- Adjusted dispatch to reduce mill cycle costs from switching the 110 MW threshold
- Implemented additional revenues for each day with negative energy margins

Fixed O&M and Capex

- Assumed total fixed costs to be [redacted] in 2018, and [redacted] in 2031 (averaging [redacted] over the 2018-2031 period), based on BREC estimates.
- The series was extended from 2031 to 2035 by using the calculated average growth over the previous five years.

Key Modeling Assumptions for 2019-2035
Station Two Costs and Parameters (cont'd)

Decommissioning costs

- Estimated to be [redacted] in 2017 by applying the $/kW decommissioning cost estimate for the Coleman plant in the Burns McDonnell 2016 study.
- Assumed [redacted] real escalation rate for future decommissioning dates.

Discount rate

- Assumed to be 8% (nominal), with a sensitivity for 5%.

Base Case Results
Annual Gross Margins

Plant Level Gross Margins

Row		Units	2019	2020	2025	2030	2035
[1]	Generation	MWh	[redacted]				
[2]	Capacity Factor	%	[redacted]				
[3]	Number of starts		[redacted]				
[4]	Fuel Costs	$m	[redacted]				
[5]	VOM	$m	[redacted]				
[6]	Startup Costs	$m	[redacted]				
[7]	Mill Cycle Costs	$m	[redacted]				
[8]	Allowance Costs	$m	[redacted]				
[9]	Total Variable Costs	$m	[redacted]				
[10]	Total Variable Costs	$/MWh	[redacted]				
[11]	Energy Price	$/MWh	[redacted]				
[12]	Energy Revenues	$m	[redacted]				
[13]	Energy Revenues	$/MWh	[redacted]				
[14]	Energy Margin ($)	$m	[redacted]				
[15]	Energy Margin ($/MWh)	$/MWh	[redacted]				
[16]	Fixed O&M and CapEx	$m	[redacted]				
[17]	Fixed O&M and CapEx	$/kW-yr	[redacted]				
[18]	Capacity Price (UCAP)	$/kW-yr	[redacted]				
[19]	UCAP Capacity	MW	[redacted]				
[20]	Capacity Revenues	$m	[redacted]				
[21]	Capacity Revenues (ICAP)	$/kW-yr	[redacted]				
[22]	Gross Margin	$m	[redacted]				
[23]	Gross Margin	$/kW-yr	[redacted]				
[24]	Gross Margin (PV Beginning 2018)	$m	[redacted]				

Exhibit Celebi-2

Base Case Results

Retirement Economics (8% Annual Discount Rate)

Retirement in 2018 results in the highest PV of gross margin for the plant, net of the cost of acceleration of decommissioning costs.

- Operating the plant until the end of 2035 reduces the gross margins by [redacted] compared to retirement at the end of 2018
- Accelerating the retirement from 2035 to 2018 increases the PV of decommissioning costs by [redacted]

Gross Margin Net of Decommissioning Costs ($millions)

Retirement at End of Year	PV of Gross Margins [1]	PV of Decomm Costs [2]	Gross Margin Net of Decomm Costs [3]
2018	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]
2031	[redacted]	[redacted]	[redacted]
2032	[redacted]	[redacted]	[redacted]
2033	[redacted]	[redacted]	[redacted]
2034	[redacted]	[redacted]	[redacted]
2035	[redacted]	[redacted]	[redacted]
2035 minus 2018	[redacted]	[redacted]	[redacted]

Exhibit Celebi-2

Base Case Results
Retirement Economics (5% Annual Discount Rate)

Retirement in 2018 results in the highest PV of gross margin for the plant, net of the cost of acceleration of decommissioning costs.

- Operating the plant until the end of 2035 reduces the gross margins by [redacted] compared to retirement at the end of 2018
- Accelerating the retirement from 2035 to 2018 increases the PV of decommissioning costs by [redacted]

Gross Margin Net of Decommissioning Costs ($millions)

Retirement at End of Year	PV of Gross Margins [1]	PV of Decomm Costs [2]	Gross Margin Net of Decomm Costs [3]
2018	[redacted]		
2019			
2020			
2021			
2022			
2023			
2024			
2025			
2026			
2027			
2028			
2029			
2030			
2031			
2032			
2033			
2034			
2035			
2035 minus 2018			

Exhibit Celebi-2

Scenarios

Scenarios
Overview

Key uncertainties affecting the future economics of the Station Two plant against the MISO market are:

- (downside) Low natural gas prices
- (downside) Potential carbon pricing
- (upside) High natural gas prices
- (upside) Low coal and fuel-oil prices
- (upside) Additional retirements of coal/nuclear plants in MISO region
- (upside) Potential additional revenues for coal plants to maintain "resiliency" benefits.

Some of these uncertainties are interrelated, such as:

- Low gas prices or introduction of carbon prices would increase regional coal/nuclear retirements (due to lower energy margins), and reduce coal prices (due to reduced domestic demand for coal).
- Low coal prices would decrease retirements, and reduce gas prices (due to reduced demand for gas).

We developed four scenarios with internally consistent combination of sensitivities.

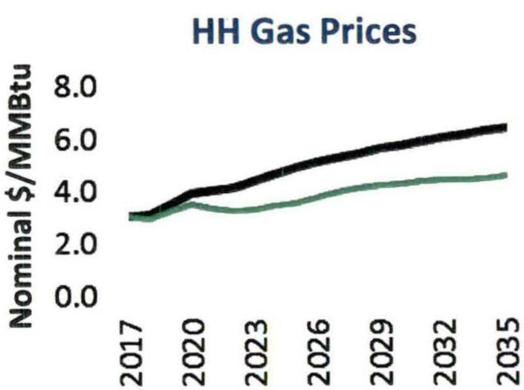
Exhibit Celebi-2

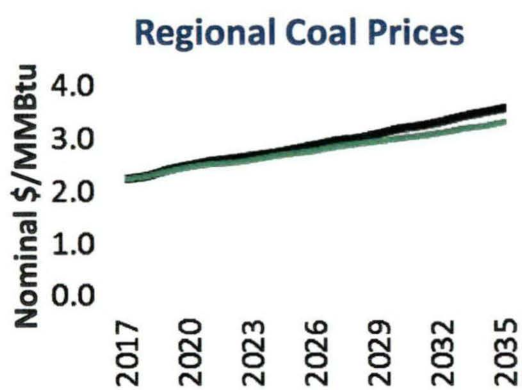
Assumptions
Scenario 1: Low Gas Prices

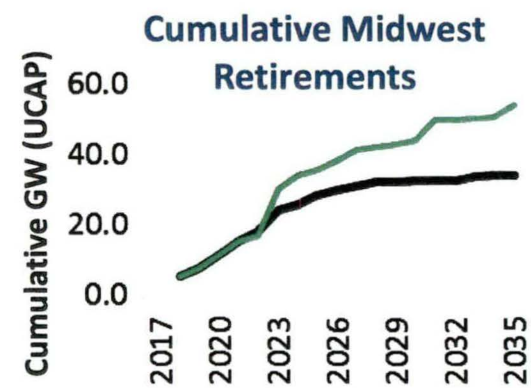
Reflects the key assumptions in AEO 2018 "High Oil and Gas Resource and Technology" case:

- Gas prices are lower than the Base Case
- Coal prices are also lower due to reduced demand for coal
- Regional retirements are higher due to reduced energy prices
- Indiana Hub energy prices are lower

Base Scenario
Scenario 1: Low Gas Prices







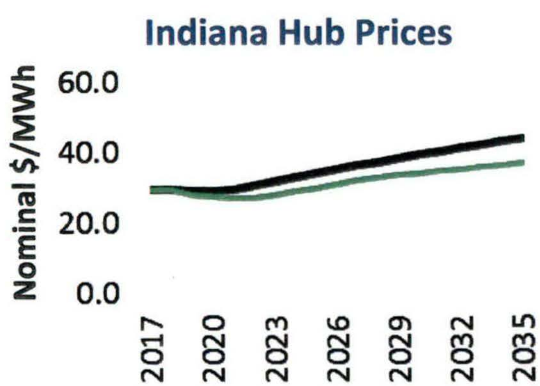
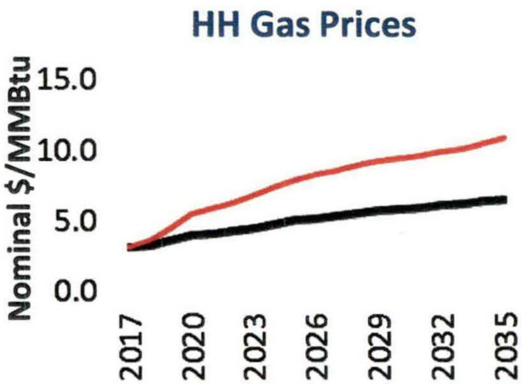


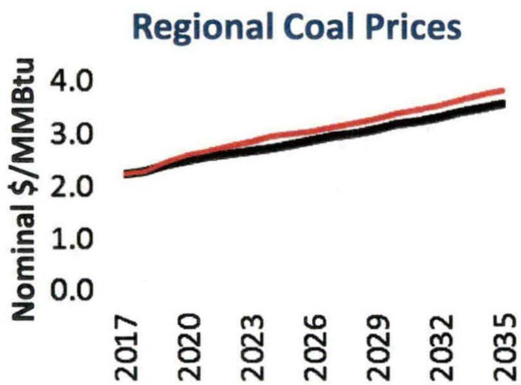
Exhibit Celebi-2

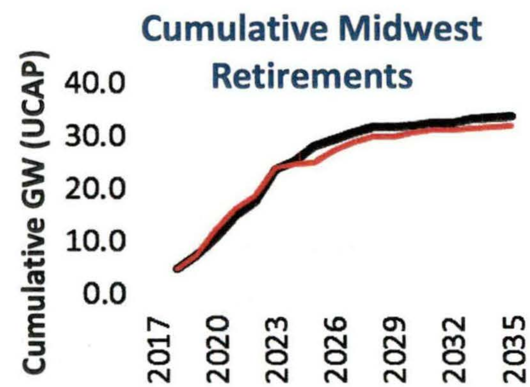
Assumptions
Scenario 2: High Gas Prices

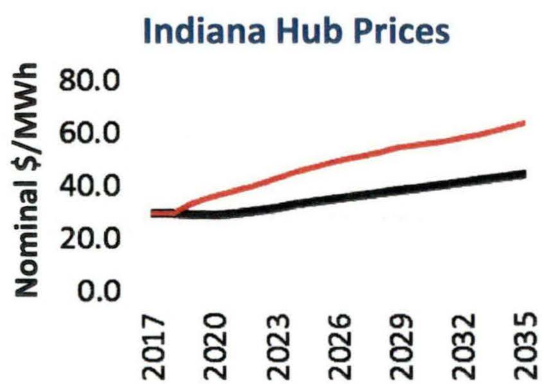
Reflects the key assumptions in AEO 2018 "Low Oil and Gas Resource and Technology" case:

- Gas prices are higher than the Base Case
- Coal prices are also higher due to increased demand for coal
- Regional retirements are slightly lower due to higher energy prices
- Indiana Hub energy prices are higher







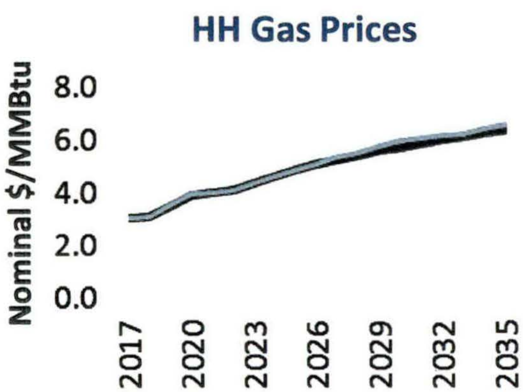


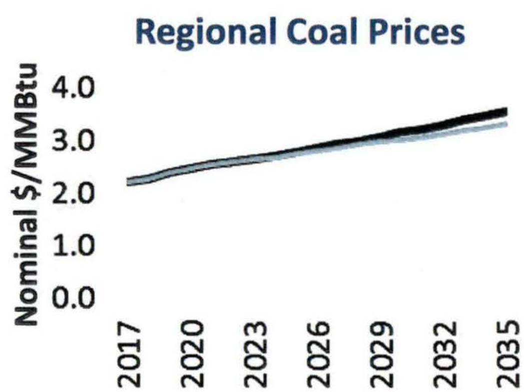
Assumptions
Scenario 3: Carbon Pricing

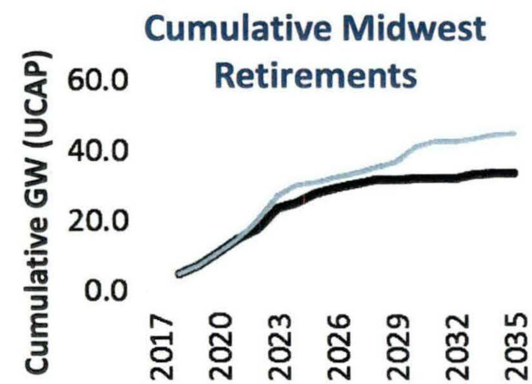
Reflects the key assumptions in AEO 2018 "Reference Case with Clean Power Plan" case, and assumes carbon prices starting in 2025 at $10/tonne, growing to $20/tonne by 2035.

- Gas prices are slightly higher than the Base Case
- Coal prices are lower due to decreased demand for coal
- Regional retirements are higher due to carbon pricing
- Indiana Hub energy prices are higher after 2025

Base Scenario
Scenario 3: Carbon Pricing







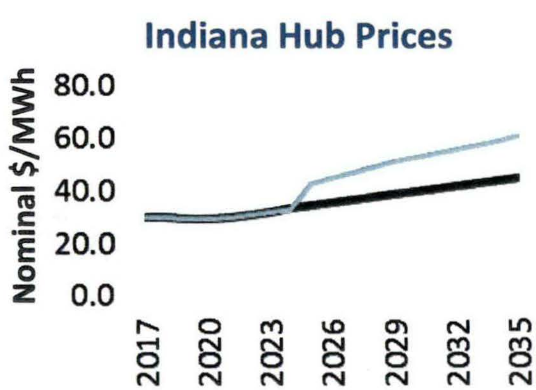
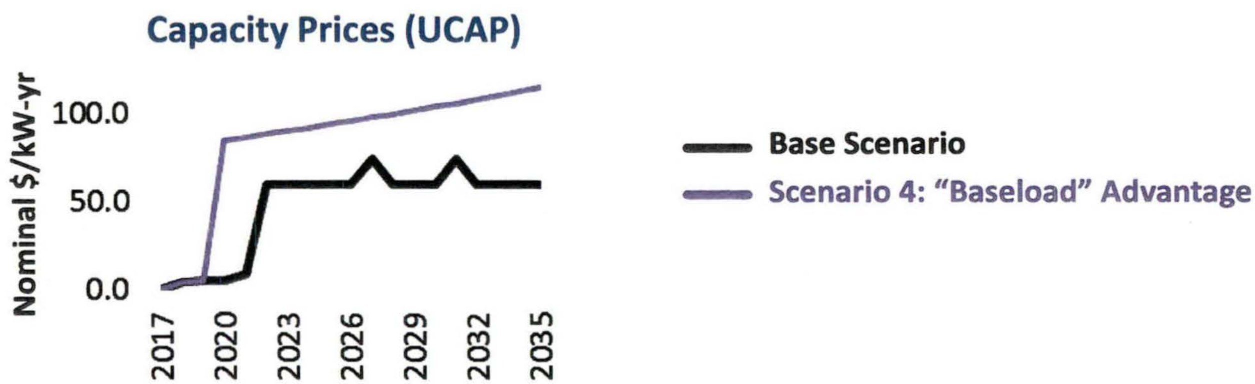


Exhibit Celebi-2

Assumptions
Scenario 4: Additional Revenues for "Baseload" Plants

Reflects the key assumptions in AEO 2018 "Reference Case", and assuming higher capacity revenues for coal plants:

- Capacity prices received by coal plants are assumed reach $79/kW-yr (in 2016 $s) by 2020
  - $79/kW-yr reflects the estimated typical annual fixed cost of a controlled existing coal plant (30-40 year-old), based on EPA's fixed O&M estimate(1) of $55/kW-yr plus EIA's ongoing CapEx estimate(2) of $24/kW-yr
- Gas prices, coal prices, and Indiana Hub energy prices remain the same as in Base Case.



Notes:
(1): Documentation for EPA Base Case v.5.13 Using the Integrated Planning Model, EPA, November 2013, Tables 4-9 (converted to 2016 $s). Available at: https://www.epa.gov/sites/production/files/2015-07/documents/documentation_for_epa_base_case_v.5.13_using_the_integrated_planning_model.pdf.
(2): Assumptions to the Annual Energy Outlook 2017, EIA, July 2017, p. 113 (converted to 2016 $s). Available at: https://www.eia.gov/outlooks/aeo/assumptions/pdf/0554(2017).pdf

Results

Scenario 1: Low Gas Prices (8% Discount Rate)

Row		Units	2019	2020	2025	2030	2035
[1]	Generation	MWh	[redacted]				
[2]	Capacity Factor	%					
[3]	Number of starts						
[4]	Fuel Costs	$m					
[5]	VOM	$m					
[6]	Startup Costs	$m					
[7]	Mill Cycle Costs	$m					
[8]	Allowance Costs	$m					
[9]	Total Variable Costs	$m					
[10]	Total Variable Costs	$/MWh					
[11]	Energy Price	$/MWh					
[12]	Energy Revenues	$m					
[13]	Energy Revenues	$/MWh					
[14]	Energy Margin ($)	$m					
[15]	Energy Margin ($/MWh)	$/MWh					
[16]	Fixed O&M and CapEx	$m					
[17]	Fixed O&M and CapEx	$/kW-yr					
[18]	Capacity Price (UCAP)	$/kW-yr					
[19]	UCAP Capacity	MW					
[20]	Capacity Revenues	$m					
[21]	Capacity Revenues (ICAP)	$/kW-yr					
[22]	Gross Margin	$m					
[23]	Gross Margin	$/kW-yr					
[24]	Gross Margin (PV Beginning 2018)	$m					

Notes: Decommissioning costs are not included in the table above.

Exhibit Celebi-2

Results

Scenario 2: High Gas Prices (8% Discount Rate)

Row		Units	2019	2020	2025	2030	2035
[1]	Generation	MWh	[redacted]				
[2]	Capacity Factor	%	[redacted]				
[3]	Number of starts		[redacted]				
[4]	Fuel Costs	$m	[redacted]				
[5]	VOM	$m	[redacted]				
[6]	Startup Costs	$m	[redacted]				
[7]	Mill Cycle Costs	$m	[redacted]				
[8]	Allowance Costs	$m	[redacted]				
[9]	Total Variable Costs	$m	[redacted]				
[10]	Total Variable Costs	$/MWh	[redacted]				
[11]	Energy Price	$/MWh	[redacted]				
[12]	Energy Revenues	$m	[redacted]				
[13]	Energy Revenues	$/MWh	[redacted]				
[14]	Energy Margin ($)	$m	[redacted]				
[15]	Energy Margin ($/MWh)	$/MWh	[redacted]				
[16]	Fixed O&M and CapEx	$m	[redacted]				
[17]	Fixed O&M and CapEx	$/kW-yr	[redacted]				
[18]	Capacity Price (UCAP)	$/kW-yr	[redacted]				
[19]	UCAP Capacity	MW	[redacted]				
[20]	Capacity Revenues	$m	[redacted]				
[21]	Capacity Revenues (ICAP)	$/kW-yr	[redacted]				
[22]	Gross Margin	$m	[redacted]				
[23]	Gross Margin	$/kW-yr	[redacted]				
[24]	Gross Margin (PV Beginning 2018)	$m	[redacted]				

Notes: Decommissioning costs are not included in the table above.

Exhibit Celebi-2

Results
Scenario 3: Carbon Pricing (8% Discount Rate)

Row		Units	2019	2020	2025	2030	2035
[1]	Generation	MWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[2]	Capacity Factor	%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[3]	Number of starts		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[4]	Fuel Costs	$m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[5]	VOM	$m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[6]	Startup Costs	$m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[7]	Mill Cycle Costs	$m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[8]	Allowance Costs	$m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[9]	Total Variable Costs	$m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[10]	Total Variable Costs	$/MWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[11]	Energy Price	$/MWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[12]	Energy Revenues	$m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[13]	Energy Revenues	$/MWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[14]	Energy Margin ($)	$m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[15]	Energy Margin ($/MWh)	$/MWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[16]	Fixed O&M and CapEx	$m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[17]	Fixed O&M and CapEx	$/kW-yr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[18]	Capacity Price (UCAP)	$/kW-yr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[19]	UCAP Capacity	MW	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[20]	Capacity Revenues	$m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[21]	Capacity Revenues (ICAP)	$/kW-yr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[22]	Gross Margin	$m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[23]	Gross Margin	$/kW-yr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[24]	Gross Margin (PV Beginning 2018)	$m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Notes: Decommissioning costs are not included in the table above.

Exhibit Celebi-2

Results

Scenario 4: Additional Revenues for "Baseload" Plants (8% Discount Rate)

Row		Units	2019	2020	2025	2030	2035
[1]	Generation	MWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[2]	Capacity Factor	%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[3]	Number of starts		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[4]	Fuel Costs	$m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[5]	VOM	$m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[6]	Startup Costs	$m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[7]	Mill Cycle Costs	$m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[8]	Allowance Costs	$m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[9]	Total Variable Costs	$m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[10]	Total Variable Costs	$/MWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[11]	Energy Price	$/MWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[12]	Energy Revenues	$m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[13]	Energy Revenues	$/MWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[14]	Energy Margin ($)	$m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[15]	Energy Margin ($/MWh)	$/MWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[16]	Fixed O&M and CapEx	$m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[17]	Fixed O&M and CapEx	$/kW-yr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[18]	Capacity Price (UCAP)	$/kW-yr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[19]	UCAP Capacity	MW	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[20]	Capacity Revenues	$m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[21]	Capacity Revenues (ICAP)	$/kW-yr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[22]	Gross Margin	$m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[23]	Gross Margin	$/kW-yr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[24]	Gross Margin (PV Beginning 2018)	$m	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Notes: Decommissioning costs are not included in the table above.

Exhibit Celebi-2

Conclusions

- In each and every year of the study period, from 2019 through 2035, and under every scenario that I evaluated, Station Two's projected annual costs will exceed its potential revenues.
- Additionally, during each year that either or both of the Station Two units continue to operate, the cumulative negative margins will worsen. Every year that retirement of Station Two is delayed will result in a greater financial loss.
- Based on the analysis that I performed, neither Unit 1 nor Unit 2 individually, nor both of them together, are capable of normal, continuous, reliable operation for the economically competitive production of electricity.
- It does not make economic sense to continue to operate either or both of the Station Two units because Station Two is not capable of economically competitive production of electricity.

APR 09 2018

Mr. Robert W. Berry
President and CEO
Big Rivers Electric Corporation, Inc.
P.O. Box 24
Henderson, Kentucky 42419-0024

Dear Mr. Berry:

We have reviewed your Section 9.1 Notice of Proposed Transaction, in Big Rivers Electric Corporation, Inc. (Big Rivers) letter dated March 6, 2018, whereby Big Rivers intends to terminate certain Contracts (as defined in the 1998 Amendment) with the City of Henderson Utility Commission. We confirmed the 1998 amendment to the Contracts between Big Rivers and the City of Henderson has the following language that allows for termination of the Contracts.

"The terms of all the Contracts except the Joint Facilities Agreement, shall be extended for the operating life of Station Two the operating life of which shall be considered to continue for so long as Unit 1 and Unit 2 or either of them is operated or is capable of normal continuous reliable operation for the economically competitive production of electricity temporary outages excepted."

Big River's stated this is not the current situation and the costs have exceeded the revenue received from this facility. Big Rivers, stated there is currently a surplus of power for their members and power from this facility is not needed. Big Rivers provided a board resolution dated March 16, 2018, to confirm the board's approval of this action.

Based on the information provided, RUS has no objections to the termination of the Contracts with City of Henderson Utility Commission. The accounting method relating to this action will be covered under a separate letter.

Sincerely,

Victor T. Vu
Deputy Assistant Administrator
Office of Portfolio Management and Risk Assessment
Electric Program
Rural Utilities Service

cc: Official File: OPMRA-LMFB (KY-62) // Reading file (Electronic KY-62) // GFR-Norman (Electronic) //

APR 0 9 2018

Mr. Robert Berry
General Manager
Big Rivers Electric Corporation
P. O. Box 24
Henderson, Kentucky 42419-0024

Dear Mr. Berry:

In response to a letter from Ms. Lindsey N. Durbin, dated March 6, 2018, we have reviewed the information submitted regarding Big Rivers Electric Corporation's (Big Rivers) expense deferral plan related to the termination of the contract costs for the Station Two expenses with the City of Henderson Utility Commission. Big Rivers will establish a regulatory asset for $89 million (approximate book value for share of plant as of 1/31/18), legal and other professional service expenses to legally terminate the contracts, and if any decommissioning costs. Big Rivers will defer these costs over an estimated 15 years.

All of the required information was submitted in the letter; therefore, the Rural Utilities Service's (RUS) approval to implement the plan is given. It should be noted, however, that our approval is based upon the understanding that these costs will be included in Big Rivers next general rate case in 2020. If the Commission does not allow the recovery of any of these costs, those deferred amounts must be written off immediately in its entirety.

Please contact the Technical Accounting and Auditing Staff at (202) 720-1922 if you have any questions or if we can be of any further assistance.

Sincerely,

Victor T. Vu

VICTOR VU
Deputy Assistant Administrator
Office of Portfolio Management and Risk Assessment

cc:
Official File (Expense Deferral 2018)
Addressee
Reading
NRAB-2 (KY 62)
OPMRA

RUS:PASD:TAAS:Glim:720-1922: S:\RUS\PASDFILES\PASD\TAAS\EXPENSE DEFERRALS\KY0062-2018.docx 3/29/18