COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

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COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION, INC. FOR AN ADJUSTMENT OF RATES	)))	Case No. 2012-00535

ATTORNEY GENERAL'S PRE-FILED TESTIMONY
PUBLIC REDACTED VERSION

Comes now the intervenor, the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention, and files the following testimony in the above-styled matter.

Respectfully submitted,
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Certificate of Service and Filing

Counsel certifies that an original and ten photocopies of the foregoing were served and filed by hand delivery to Jeff Derouen, Executive Director, Public Service Commission, 211 Sower Boulevard, Frankfort, Kentucky 40601; counsel further states that true and accurate copies of the foregoing were mailed via First Class U.S. Mail, postage pre-paid, to:

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC	)	
CORPORATION FOR A GENERAL	)	Case No.
ADJUSTMENT IN RATES	)	2012-00535

DIRECT TESTIMONY

OF

DAVID BREVITZ, C.F.A.

ON BEHALF OF

KENTUCKY OFFICE OF ATTORNEY GENERAL

PUBLIC REDACTED VERSION

FILED: May 24, 2013

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BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2012-00535

DIRECT TESTIMONY OF

DAVID BREVITZ

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is David Brevitz. My business address is 3623 SW Woodvalley Terrace, Topeka, Kansas.

Q. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am an independent consultant serving state regulatory commissions, Attorney General's Offices, and consumer organizations. I am testifying on behalf of the Kentucky Office of the Attorney General.

Q. DO YOU HAVE SPECIFIC EXPERIENCE, EXPERTISE AND DIRECT KNOWLEDGE REGARDING THE SUBJECTS WHICH ARE CONTAINED IN YOUR TESTIMONY?

A. Yes. Over the course of decades of experience in economic regulation of public utilities at the state commission level I have developed expertise in the public utility concept, economic characteristics of public utilities, the rate case process and determination of revenue requirements, public utility cost of service principles, and public utility financing and reorganization transactions. I have conducted several detailed and extensive analyses of proposed utility financial transactions and related utility regulatory policies, under the relevant laws in those states. On behalf of the Attorney General I have addressed two such transactions in Kentucky:

- The proposed spin-off of Alltel's wireline telephone division ("Windstream"), and subsequent merger with Valor Communications in a reverse Morris Trust transaction on a tax-free basis, which included incurrence of substantial new debt by Windstream, and payments and other transactions including special dividends to Alltel.
- The "Unwind" transaction between Big Rivers Electric Corporation ("BREC") and E.ON. The "Unwind" engagement was limited to assessing whether BREC would be financially viable on a going forward basis following any approval of the transaction, based on review of the financial projections of BREC. The financial projections included a scenario if both smelters left the system. My review included the nature and extent of the BREC organization, both current and proposed; statements and rationale offered by Joint Applicants as to why the proposed transactions were in the public interest; internal managerial analyses, presentations and reports of E.ON, BREC and its member cooperatives, and the smelters; and, the

proposed agreements among BREC, Kenergy and the aluminum smelters, including provisions for termination of the agreements.

My training and experience in public utility regulation began while studying at the Institute of Public Utilities in the Economics Department at Michigan State University. This program covered principles of public utility regulation, and addressed development and application of state commission utility regulatory practices in detail for electric, gas and telephone utilities. While at Michigan State, I earned an undergraduate degree in Justice, Morality and Constitutional Democracy from James Madison College (a residential college at MSU) and an MBA in Finance (1980). Since that time, I have worked on numerous matters for state utility commissions, consumer advocates, Attorneys General, and international regulatory bodies. Further description of my background and experience is provided on Exhibit DB-1.

Q. DO YOU HAVE OTHER RELEVANT QUALIFICATIONS?

A. Yes. In 1984 I was designated as a Chartered Financial Analyst by the Institute of Chartered Financial Analysts ("ICFA"), which later became the CFA Institute. The CFA Institute is the organization which has defined and organized a body of knowledge important for all investment professionals. The general areas of knowledge are ethical and professional standards, accounting, statistics and analysis, economics, fixed income securities, equity securities, and portfolio management.

I have been designated as a Senior Fellow by the Public Utilities Research Center at the University of Florida ("PURC"). This designation is reserved for knowledgeable and experienced professionals who foster strong ties to academia, industry, and government, who embody PURC's values of respect, integrity, effectiveness and expertise, and who support PURC's mission to contribute to the development and availability of efficient utility services through research, education, and service.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS MATTER?

A. The purpose of my testimony is to address BREC's "precarious financial position"[1] in light of BREC's mission; recent BREC financing activities; financial model considerations as presented in this case; and, recommendations to the Commission regarding application of the "fair, just and reasonable rates" and "used or useful" standards associated with public utility ratemaking.

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[1] Direct Testimony of Mark A. Bailey on behalf of Big Rivers Electric Corporation, at page 7, line 18. Hereafter cited as "Bailey Direct Testimony."

BREC's Precarious Financial Position

Q. WHAT IS YOUR UNDERSTANDING OF BREC'S "PRECARIOUS FINANCIAL POSITION"?

A. BREC has been in a precarious financial position since the Unwind Transaction. In each year following the Unwind, BREC has been deferring maintenance outages "because that was the only option for BREC to meet the minimum margins for interest ratio required by its loan agreements."[2] The apparent cause of this was "depressed off system sales revenues," where BREC "derives almost all of its margins."[3] BREC's precarious financial position has been dealt another very material blow from the announced departures of Century Aluminum of Kentucky ("Century") and Alcan Primary Products Corporation ("Alcan," and together "the smelters") from BREC's system. Century is the source of approximately 36% of BREC's wholesale revenues, and Alcan is the source of approximately 28% of wholesale revenues, for a total of 64%.[4] BREC has filed this rate case "principally to cover revenues lost from Century's termination and a decline in the off-system

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[2] Direct Testimony of Robert W. Berry on behalf of Big Rivers Electric Corporation, at page 8, line 12. Hereafter cited as "Berry Direct Testimony."
[3] Bailey Direct Testimony at page 8, line 1.
[4] Corrective Plan to Achieve Two Credit Ratings of Investment Grade; Big Rivers response to PSC 3-9, Attachment 1, at page 2.

sales market"[5] and will be filing another rate case in a matter of months to address the Alcan departure. BREC also has plans to "lay-up" or reduce generating capacity to cut costs.[6] While BREC has a "Mitigation Plan" to bring new load to its system, it will be at least three years before this can have a meaningful impact.[7] As described in more detail below the mitigation plans offered by BREC are subject to a great deal of uncertainty. More recently, BREC has stated in the Corrective Plan it submitted to U.S. Rural Utilities Service ("RUS") that it "believes completion of the entire process will most likely take three to four years,"[8] where the "entire process" refers to "rate relief," "successful implementation of its Load Concentration Mitigation Plan" and pay down of the $58.8 million Pollution Control Bond issue due June 1, 2013. Of these three elements, results from the Mitigation Plan are most uncertain, and will take years for potential development of any material results. BREC states its "current long-term Financial Model indicates Wilson Station will restart in 2019."[9] Note that the "current long-term Financial Model" does not include the effects of Alcan's departure, despite the fact

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[5] Bailey Direct Testimony, page 9, line 9.
[6] "Laying up" and "mothballing" generating plant are generally equivalent terms for a shutdown state, as discussed in Big Rivers' response to PSC Staff 2-21e. Since Big Rivers has used the term "lay up" in this case, I will also use that term for the sake of clarity.
[7] Bailey Direct Testimony, page 12, line 6.
[8] Big Rivers Response to AG 2-37, Attachment 1, at page 7.
[9] Big Rivers Response to PSC Staff 2-21(c).

this event will occur well within BREC's fully forecasted test year it has proposed for use in the current case.

For some time BREC has been repurposing funds that had been earmarked for specific uses. For example, since the Unwind BREC has deferred maintenance to make the margins required by debt covenants, and has used funds borrowed for the ordinary course of business to redeem bonds. Also, the BREC response to PSC 3-3 shows an increasing inability to fund budgeted capital projects, as follows:

Construction Budget versus Actual

Years	Actual	Budget	Variance
2012	$ 39.8	$ 83.3	$ 43.5
2011	$ 38.4	$ 53.0	$ 14.6
2010	$ 44.5	$ 45.6	$ 1.1

The Unwind Transaction and the Smelter Agreements

Q. PLEASE BRIEFLY DESCRIBE THE "UNWIND TRANSACTION" WHICH CREATED BREC'S CURRENT SCOPE OF OPERATIONS.

A. The "Unwind Transaction" was defined by Joint Applicants to be "the combined transactions by which BREC and the E.ON entities propose to terminate and unwind the 1998 Transactions."[10] The 1998 transactions were part of BREC's implementation of its bankruptcy reorganization, and included the following components: leasing BREC's generating facilities to E.ON's predecessor for it to manage, operate and maintain; transferring responsibility to manage, operate and maintain two additional generating units owned by the City of Henderson (through Henderson Municipal Power & Light, or "HMPL"); purchasing by BREC of a set amount of power at substantially fixed prices through a Power Purchase Agreement that it used to serve the loads of its three member cooperatives; payment by LG&E Energy Marketing ("LEM") to the U.S. Rural Utilities Service of monthly margin payments; and, providing a portion of the smelters' power needs at substantially fixed rates through power supply contracts between LEM and predecessors of Kenergy. The facilities lease and power purchase agreements were to terminate in 2023 by the terms of those agreements, and the power supply contracts for the smelters were to terminate in 2010-2011.

Q. WHAT CONCERNS DID YOU EXPRESS IN THE UNWIND PROCEEDING ON BEHALF OF THE ATTORNEY GENERAL?

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[10] *Applications of Big Rivers Electric Corporation for: (1) Approval of Wholesale Tariff Additions for Big Rivers Electric Corporation, (2) Approval of Transactions, (3) Approval to Issue Evidences of Indebtedness, and (4) Approval of Amendments to Contracts; and of E.ON U.S., LLC, Western Kentucky Energy Corp. and LG&E Energy Marketing, Inc. for Approval of Transactions,* Case No. 2007-00455 , Application at paragraph 10.

A. In my Direct and Supplemental testimonies in Case No. 2007-00455, I expressed a range of concerns which have come to pass. The confidential version of my Direct testimony in that case contains information which I believe will be helpful to the Commission in addressing the issues of the present case. The confidential version of my Direct testimony should still be on file at the Commission. The public redacted versions of both my Direct and Supplemental testimonies filed in the Unwind case are attached hereto as Exhibit DB-2.

Q. DID THE SMELTERS HAVE A MATERIAL ROLE IN THE UNWIND TRANSACTION?

A. Yes. Addressing the impending termination of the smelter power supply contracts with LEM and Kenergy was a major facet of the Unwind Transaction, as otherwise "the Smelters would have [had] to meet all of their power requirements by market purchases."[11] Market prices at that time were relatively high. One result of negotiations among BREC, E.ON and the smelters was the smelter contracts that were approved as part of the Unwind Transaction. These contracts (the "Smelter Agreements") included a "Retail Agreement" between each smelter and Kenergy; a "Wholesale Agreement" between each smelter and BREC; and, a "Coordination

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[11] *In the Matter of the Applications of Big Rivers Electric Corporation for: (1) Approval of Wholesale Tariff Additions for Big Rivers Electric Corporation, (2) Approval of Transactions, (3) Approval to Issue Evidences of Indebtedness, and (4) Approval of Amendments to Contracts; and of E.ON U.S., LLC, Western Kentucky Energy Corp. and LG&E Energy Marketing, Inc. for Approval of Transactions,* Case No. 2007-00455, Order (March 6, 2009), page 14. Hereafter referred to as the "Unwind Order."

Agreement" between each smelter and BREC.[12] It was anticipated that the Smelter Agreements would "provide them power at competitive prices while providing protections to Big Rivers and its non-Smelter customers against the risks inherent in resuming the role of power supplier to the Smelters."[13] It was expected that "a long term supply of power [would] be available for the Smelters at prices below those in the market"[14] as a result of the Unwind transaction. Additionally, the smelters were provided several different payments and escrow arrangements via the Unwind transaction from BREC and E.ON that appear to have been paid to the smelters in the first two years following the Unwind.[15] The smelters also negotiated a rebate by which BREC would pay the smelters the excess of any BREC margins exceeding a 1.24 Times Interest Earned ("TIER") level.

Q. DO THE SMELTER AGREEMENTS CONTAIN PROVISIONS ALLOWING EACH SMELTER TO TERMINATE THE AGREEMENTS?

A. Yes. There are provisions that would have allowed the smelters to terminate the agreements prior to the "Effective Date," which has passed. The agreements may also be terminated for an event of default. Finally and as described in more detail below, under Section 7.3.1, the retail agreements may be terminated by the smelter

[12] Unwind Order, Appendix C.
[13] Unwind Order, pages 15-16.
[14] Unwind Order, page 22.
[15] Unwind Order, pages 16-17.

closing. Such termination could not have been effective prior to December 31, 2010.[16] "Upon the termination of a retail smelter agreement, either Kenergy or BREC may terminate the wholesale power supply agreement related to a Smelter retail service agreement."[17]

Q. UNDER WHAT PROVISION DID THE SMELTERS TERMINATE THE CONTRACTS?

A. Both smelters provided Notice of Termination of the retail contract with Kenergy under Section 7.3.1 of that contract, which is "Termination for Closing [Hawesville or Sebree] Smelter" (emphasis added).[18] Such termination requires the smelter to provide "a certificate of the president of [Century or Alcan] Parent including a representation and warranty that it has made a business judgment in good faith to terminate and cease all aluminum smelting at the [Sebree or Hawesville] Smelter and has no current intention of commencing smelting operations at the [Sebree or Hawesville] Smelter"[19]—such certificate has to be provided for the Notice to be effective. BREC's Corrective Plan provided to RUS also states as "background":

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[16] *E.g.*, Century Retail Electric Service Agreement with Kenergy, Article 7.

[17] *In the Matter of the Application of Big Rivers Electric Corporation for Approval to Issue Evidences of Indebtedness*; Case No. 2013-00125; March 27, 2013, Application at page 4, line 2. Also referred to, infra, as the "CFC Amended and Restated Line of Credit Application."

[18] *See, e.g.*, Century Retail Electric Service Agreement with Kenergy, Section 7.3.1 at page 32.

[19] *See, e.g.*, Century Retail Electric Service Agreement with Kenergy, Section 7.3.1 at page 32, emphasis added.

- The Century notice "indicated Century is <u>ceasing all smelter operations</u> at their Hawesville, Kentucky facility on August 20, 2013"; and,
- The Alcan notice "indicated Alcan is <u>ceasing all smelter operations</u> at their Sebree smelter located in Robards, Kentucky on January 31, 2014."[20]

Q. ARE THE SMELTERS CLOSING, AND TERMINATING AND CEASING ALL ALUMINUM SMELTING?

A. It does not appear the smelters are closing at the present time. Instead, following the termination notices, the smelters have sought ways to obtain power from the market versus obtaining it from BREC through Kenergy. BREC states "it is not certain whether Century will be operating."[21] BREC responses to KIUC 2-29 and 2-31 describe the status of negotiations with Alcan and Century, respectively, regarding continued power supply, but from the wholesale power market.[22]

Q. DO BREC'S LENDERS APPEAR TO QUESTION WHETHER THE SMELTERS HAVE PROPERLY TERMINATED THE SMELTER AGREEMENTS?

A. Yes. The Amended and Restated Revolving Line of Credit agreement between the National Rural Utilities Cooperative Finance Corporation ("CFC") and BREC adds

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[20] Big Rivers response to AG 2-37, Corrective Plan provided to RUS, attachment 1, page 2, <u>emphasis added</u>.
[21] Big Rivers response to KIUC 2-3a.

[22] Multiple press stories since that time have indicated that Century, BREC and Kenergy have apparently reached at least a working preliminary agreement in this regard.

language regarding "termination [of the smelter agreements] purported to be in accordance with the voluntary termination aspects of such wholesale power contracts, whether or not challenged by Borrower," and also adds the remedy for CFC of seeking damages in the event of default.[23] This suggests to me that CFC may be concerned regarding proper termination of the smelter agreements under the voluntary termination provisions of those agreements.

Q. IS THERE DISCUSSION OF THE SMELTERS IN THE BREC BOARD OF DIRECTORS' MEETING MINUTES THAT THE COMMISSION SHOULD BE AWARE OF?

A. Yes. The minutes from BREC Board of Directors[24] meetings were provided by BREC under confidential protection in response to AG 1-38. Pages 838-839 contain minutes **[BEGIN CONFIDENTIAL]** [redacted]

[23] *In the Matter of the Application of Big Rivers Electric Corporation for Approval to Issue Evidences of Indebtedness;* Case No. 2013-00125, Application dated March 27, 2013, Exhibit 4, at pages 12 and 17, emphasis added.
[24] Big Rivers' directors are identified by organization in its response to PSC Staff 1-28.

[redacted] **[END CONFIDENTIAL]**

There certainly is a basis for differing interests between the customers of the retail member that serves the smelters - Kenergy - and the customers of the other two members - Jackson Purchase and Meade County - who do not. These differences may be expected to grow as BREC proposes to increase rates for all retail members to pass through the costs of excess capacity caused by the departure of the smelters. Consumers served by Jackson Purchase and Meade County may reasonably wonder why they are being assessed costs through increased rates which are beyond those necessary to furnish efficient and sufficient electric service.

Q. DOES ANY OF THE FOREGOING DISCUSSION OF THE TERMINATION PROVISIONS OF THE SMELTER AGREEMENTS CONSTITUTE A LEGAL OPINION?

A. No, I am not an attorney so the discussion does not constitute a legal opinion. The discussion above is based on a plain reading of the smelter agreements and Line of Credit agreement language.

Q. DOES BREC HAVE A SYMBIOTIC RELATIONSHIP WITH THE SMELTERS?

A. Yes, in the sense that BREC's financial health is inextricably tied to the smelters. The smelters represent over 60% of BREC's load. BREC has constructed its system and invested hundreds of millions of dollars in order to serve the smelter load, and the Unwind Transaction assumed BREC would continue to serve the smelter load over the long term. The smelter departure removes revenues which supported the capital and operating costs of the BREC system, which leaves BREC in a very precarious financial position.

Debt Leverage

Q. **DOES BREC'S DEBT LEVERAGE CONTRIBUTE TO ITS PRECARIOUS FINANCIAL POSITION?**

A. Yes. BREC operates with a significant amount of debt as compared to equity. Higher debt leverage is associated with higher risk and higher reward. The risk component derives from the fact that higher debt levels require higher levels of fixed debt service (payment of principal and interest) such that there is an increasing risk that earnings (cash) will be insufficient to meet those fixed debt service obligations, all other things equal. BREC is unable to benefit from the reward component due to the rebate provision in the smelter agreements for all margins over the 1.24 "Contract TIER" level. The Contract TIER rebate provision obviated any opportunity for BREC to secure its financial position in good times by accumulating margins, and left it with only the prospect of a marginal existence in the narrow band between 1.1 MFIR and 1.24 TIER.

A debt ratio may be calculated using end-of-year 2012 data from the preliminary RUS Financial and Operating Report:

Total Margins and Equities	$	402,881	
Total Long Term Debt	$	845,317	67.7%
Total Capitalization	$	1,248,198	

BREC has relatively high levels of debt as compared to equity, with associated fixed debt service obligations.

Furthermore, high debt leverage increases BREC's exposure to interest rate risk which is caused by rising interest rates. BREC faces the risk of higher interest expense where variable interest rates apply and in connection with future financing.

The prospective reduction in revenues from the departure of the smelters has triggered significant negotiations among BREC and its lenders. Continued liquidity is a concern being addressed and BREC's options are narrowing over time. An example of these narrowing options include the fact that BREC was obliged to use CoBank funds originally approved by the Commission for use in the normal course of business to instead repay maturing Pollution Control Bonds (as approved in Case No. 2012-00492). Then, BREC used the $35 million Transition Fund balance to partially replace the CoBank funds, intended for later use for capital expenditures.[25] A further example of narrowing options is the renegotiated CFC Line of Credit currently before the Commission for approval in Case No. 2013-00125. BREC was required to renegotiate this Line of Credit agreement by the fact that the departure of the smelters would be an Event of Default, allowing

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[25] *In the Matter of the Application of Big Rivers Electric Corporation for Approval to Issue Evidences of Indebtedness*, Case No. 2012-00492, Order (March 26, 2013) at page 4.

CFC (at its discretion) to accelerate all unpaid principal and interest on obligations between BREC and CFC. These obligations include the Line of Credit, first mortgage notes in the amount of $302 million, and a promissory note in the amount of $43 million.[26] The renegotiated terms of the CFC Amended and Restated Line of Credit include more restrictive terms such as limiting advances under the CFC Revolver to times when BREC's available cash is less than $35 million, and requiring repayment on Line of Credit balances when available cash balances exceed $35 million.[27] This serves to create a narrow band for use of the Line of Credit, and also would tend to keep such use more temporary—eliminating BREC's management discretion to retain the funds for a longer period. Also, the renegotiated terms provide CFC the remedy of pursuing damages from BREC in the event of default.[28] Further the renegotiated terms prohibit BREC from using an advance from the Line of Credit "to pay any portion of the principle amount of the $58,800,000 County of Ohio, Kentucky, Pollution Control Floating Rate Demand Bonds."[29] Finally, the renegotiated terms limit BREC's financial flexibility by requiring BREC to maintain a minimum member equity balance, and each year to add 75% of positive net margins for the particular fiscal year to that

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[26] CFC Amended and Restated Line of Credit Application, at pages 4-5.
[27] CFC Amended and Restated Line of Credit Application, at page 7. *See also*, Exhibit 4, which is a redline version of the Amended and Restated Line of Credit Agreement.
[28] CFC Amended and Restated Line of Credit Application, Exhibit 4, page 17.
[29] *Id.*, at page 7.

minimum member equity balance.[30] The renegotiated terms also change the Line of Credit from being unsecured, to being secured under BREC's Indenture.

BREC is in a poor position to handle any further negative results from its operating position. BREC faces various exigencies, including exposure to requests for credit enhancements from suppliers,[31] and its options for dealing with these are narrowing over time.

BREC's Corrective Plan and Mitigation Plan

Q. IS BREC IN THE PROCESS OF IMPLEMENTING A "CORRECTIVE PLAN" UNDER THE SUPERVISION OF THE RURAL UTILITIES SERVICE (RUS)?

A. Yes. The Loan Agreement between BREC and RUS requires that BREC maintain at least two investment grade credit ratings, and to notify RUS within 5 days of a failure to maintain such credit ratings. Following Alcan's Notice of Termination, Standard and Poor's downgraded BREC's credit rating below investment grade (to BB-) on February 4, 2013, and Fitch Rating downgraded to BB on February 6, 2013. BREC properly notified RUS of these downgrades below investment grade. Subsequent to that notification the Loan Agreement requires BREC to provide a

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[30] *Id.*, Exhibit 4, page 14.

[31] *See*, Big Rivers' responses to KIUC 1-61 and 2-27. Also, Big Rivers' response to KIUC 1-60 states "The recent credit rating downgrades resulted in Big Rivers being required to post an additional $3 million letter of credit with MISO."

"written plan satisfactory to the RUS setting forth the actions that shall be taken that are reasonably expected to achieve two Credit Ratings of Investment Grade."[32] The Corrective Plan provided to RUS is dated March 7, 2013.

Q. WHAT DOES THE CORRECTIVE PLAN WHICH BREC PROVIDED TO RUS ADDRESS?

A. The Corrective Plan addresses items BREC states the credit ratings agencies focus upon, as follows: "access to and maintenance of liquidity"; "replacement load for BREC's two largest customers who have given notice of termination"; and, "increased BREC's activity in off-system sales market."[33]

- Access to and maintenance of liquidity:
  - Lines of Credit: BREC has completed negotiations with CFC for "major modifications" to the terms associated with its $50 million line of credit which modifications were required due to the termination notices; and, BREC presently is unable to draw on its CoBank $50 million line of credit due to the Century termination notice. The original CFC and CoBank lines of credit were approved in connection with the Unwind Transaction. BREC stated it would "restart negotiations" with CoBank to

[32] Big Rivers Response to PSC 3-9, Attachment 1, page 2.
[33] *Id.*, at page 4.

attempt to restructure the line of credit later in March, 2013.[34] BREC has made the necessary application to the Commission to issue new evidences of indebtedness to implement the major modifications to the CFC line of credit,[35] the day after it received the Commission's order on its prior financing application in Case No. 2012-00492.

- Environmental Compliance Plan financing: BREC is faced with the necessity of financing its Mercury and Air Toxics Standards (MATS) compliance plan as approved by the Commission. BREC plans to use short term financing from CFC as a three year "bridge," and seek long term financing from RUS. "BREC is planning to submit its application to RUS by mid-April and file a financing application with the PSC for the CFC interim financing shortly thereafter."[36]
- Century Rate Case: BREC states it has sought $74 million in increased revenues from the Commission.
- Alcan Rate Case: BREC states it "plans to file another general rate case in late June 2013 to address the annual revenue deficiency resulting from Alcan's contract termination."

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[34] *Id.*, at page 5.
[35] *In the Matter of the Application of Big Rivers Electric Corporation for Approval to Issue Evidences of Indebtedness*, Case No. 2013-00125, Application dated March 27, 2013.
[36] Big Rivers Response to PSC 3-9, Attachment 1, at page 5.

- Pollution Control Bond Refinancing: BREC must redeem $58.8 million in bonds which mature in June 2013, proceeds from which financed installation of pollution control equipment at Wilson. BREC originally sought approval to redeem these bonds with proceeds from issuance of a like amount of bonds. However, this plan became uncertain and therefore impractical given BREC's changed financial picture due to the smelter terminations—it became uncertain whether investors would in fact purchase the new bonds, and what interest rate would be required by the investors for an appropriate risk adjusted return. BREC therefore proposed to use remaining proceeds from its CoBank secured loan—that was approved by the Commission for capital expenditures—to redeem the bonds at or before maturity. BREC also asked for Commission approval to use the $35 million transition reserve fund to partially replenish the CoBank funds. The Commission granted the approvals sought by BREC in its amended application.[37]

- "Replacement Load and Addressing Reliance on Off-System Sales" is addressed in the Corrective Plan by also providing to RUS the BREC Mitigation Plan.

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[37] *In the Matter of Application of Big Rivers Electric Corporation for Approval to Issue Evidences of Indebtedness,* Case No. 2012-00492, Order (March 26, 2013).

Q. PLEASE ADDRESS BREC'S "MITIGATION PLAN."

A. Mr. Berry describes the mitigation steps being taken by BREC to address the Century contract termination, via implementation of BREC's Load Concentration Mitigation Plan, in his testimony at pages 19-25. The Mitigation Plan itself is provided under protection of confidentiality, but Mr. Berry addresses the Plan in a general way in his public testimony. The Mitigation Plan is comprised of four elements, in order:

- "Petition the Commission for a rate increase";
- "market all excess power";
- "idle or reduce generation"; and,
- "execute forward bilateral sales with counterparties, enter into wholesale power agreements, and/or participate in capacity markets."[38]

While this rate case proceeding will occur under statutory timelines, the remaining three elements of the Mitigation Plan are all uncertain, longer term, and therefore should be viewed as risky. BREC is shifting this risk to remaining rural and large industrial consumers through its request for increased rates in this matter.

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[38] Berry Direct Testimony, pages 19-20.

- Marketing of excess power "is not expected to be an effective mitigation method for the next few years," since "off-system sales margins will remain depressed."[39]

- Idling or reducing generation shifts the carrying costs of that unused plant to remaining rural and large industrial consumers for an indefinite time period, under BREC's approach of increasing rates to make up for lost load and margins during that indefinite time period.

- For a variety of reasons, efforts to find load replacement "will require three or four years to come to full fruition."[40]

The steps in BREC's Mitigation Plan that lead to reducing the scale of BREC operations to appropriate size for its remaining load take BREC in the right direction, but are still very uncertain. Remaining rural and large industrial consumers should not be required to pay rates which are not fair, just and reasonable for the indeterminate period of time—three or four years, or more—before the Mitigation Plan (assuming it works as BREC anticipates), is able to properly align BREC's system load with its generating resources—without significant excess capacity.

[39] *Id.*, at page 20.
[40] *Id.*, at page 21.

Q. IS THE MITIGATION PLAN IN DIRECT CONFLICT WITH BREC'S REQUEST TO INCREASE RATES IN THIS CASE?

A. Yes. BREC's request to increase rates for large industrial consumers in this case and prospective further increases to those rates is in direct conflict with BREC's efforts under the Mitigation Plan to attract new large industrial load. Prospective large industrial consumers will be dis-incented by BREC's "precarious financial position" along with planned and announced (but unspecified) future rate increases. All other things being equal, this conflict serves to defer the point at which replacement load becomes an effective mitigation to BREC's current "precarious financial position," and thus also extend the period of time that remaining rural and large industrial consumers are being asked by BREC to pay rates which are not fair, just and reasonable.

Market Prices and Financial Projections

Q. PLEASE DESCRIBE THE IMPORTANCE OF MARKET PRICES FOR OFF-SYSTEM SALES TO BREC.

A. Off-system sales margins were a key underpinning of the financial projections provided by BREC in the Unwind case. Relatively high off-system sales prices were an essential component of making the numbers work out within the financial modeling associated with the Unwind transaction. Projected financial results were a significant consideration for the Commission in addressing the proposed transaction. When projected off-system sales, as portrayed in the Unwind case's financial model are contrasted with actual results and updated projections from BREC's response to KIUC 2-44 a stark result emerges:

[BEGIN CONFIDENTIAL PORTIONS]

Off-System Sales

Average Annual Sales Price

($/MWh)

	Unwind Model	Actual/ Projected
2012	$ [redacted]	$ [redacted]
2013	$ [redacted]	$ [redacted]
2014	$ [redacted]	$ [redacted]
2015	$ [redacted]	$ [redacted]
2016	n/a	$ [redacted]

[END CONFIDENTIAL PORTIONS]

BREC, which was already heavily dependent financially on higher market prices for off-system sales, will become *even more* dependent on off-system sales following the departure of the smelters given the excess capacity those departures create. The higher margins projected for off-system sales in the Unwind proceeding have not materialized, and BREC therefore finds itself in a "precarious financial position."

Q. PLEASE COMPARE SELECT BALANCE SHEET AND INCOME STATEMENT ITEMS FROM THE UNWIND FINANCIAL MODEL PROJECTIONS TO BREC'S ACTUAL 2012 FIGURES AND PROJECTED 2013 FIGURES.

A. The final Unwind financial model contains projections for 2009 and subsequent fiscal years and was provided by BREC in response to AG 1-7. BREC provided its preliminary RUS Financial and Operating Report for 2012 in response to AG 1-162. Financial and operating projections for 2013 were provided by BREC in response to PSC Staff 1-57. Selected balance sheet and income statement items can be compared as follows:

	Unwind 2012	Preliminary 2012	Variance	Unwind 2013	Projected 2013	Variance
Total Operating Revenues	$ 634.3	$ 568.3	$ (66.0)	$ 666.8	$ 545.4	$ (121.4)
Reserve Funds	$ 38.3			$ 35.7		
Total	$ 672.6	$ 568.3	$ (104.3)	$ 702.5	$ 545.4	$ (157.1)
			-16%			-22%
Fuel Costs	$ 339.5	$ 226.4	$ (113.1)	$ 366.4	$ 227.2	$ (139.2)
Total Costs	$ 658.7	$ 558.1	$ (100.6)	$ 689.3	$ 543.8	$ (145.5)
Net Margin	$ 13.9	$ 11.3	$ (2.6)	$ 13.2	$ 5.0	$ (8.3)
			-19%			-63%
Interest Expense	$ 51.4	$ 45.0	$ (6.4)	$ 48.3	$ 46.3	$ (2.0)
Margins and Equities	$ 426.9	$ 402.9	$ (24.0)	$ 440.1	$ 402.2	$ (37.9)
Long Term Debt	$ 834.5	$ 845.3	$ 10.8	$ 810.9	$ 943.2	$ 132.3
Capital Expenditures				$ 50.1	$ 79.1	$ 29.0

Analysis of the variances for these two years provides a very stark result, and uniformly indicates an increasingly large gap between where BREC told the Commission it would be in the Unwind case, and its present precarious financial position.

- Revenues: BREC's actual revenues were $104 million less than the Unwind model's prediction for 2012, and are projected to be $157 million less than predicted in 2013, including the last four months of 2013 without Century revenues. As a percentage, these shortfalls are 16% for 2012 and 22% for 2013 as contrasted with the Unwind model's prediction. Both the size and the trend of these shortfalls are very troubling.
- Total Costs: BREC's actual total costs were $100 million less than predicted the Unwind model's prediction for 2012, but fuel costs were $113 million less indicating that BREC's other costs were approximately $13 million higher than predicted. This is in spite of the actual-cost reducing impacts of deferring maintenance and scheduled outages. BREC's projected costs for 2013 are $145 million less than the Unwind model predicted, and some portion of that would be due to the departure of Century for the last four months of 2013.
- Net Margins: Net margins are $2.6 million less than the Unwind model predicted for 2012, and are projected to be $8.3 million less in 2013. As a

percentage, these shortfalls are 19% for 2012 and 63% for 2013 as contrasted with the Unwind model's predictions. Both the size and the trend of these shortfalls are very troubling.

- Margins and equities: BREC's Unwind model predicted that its equity position would reach $427 million in 2012 and $440 million in 2013. However, BREC's actual and projected margin accumulation is falling increasingly short of the Unwind model predictions. BREC projects that it will be $38 million short of its predicted margins and equities level at the end of 2013.

- Long Term Debt: BREC's Unwind model predicted LTD balances of $834 million at the end of 2012, and $811 million at the end of 2013. The Unwind model predicted <u>declining</u> LTD levels. This is perhaps the most troubling element of the comparison of predicted to "actual" balances. BREC had $11 million more in Long Term Debt in 2012 than was predicted by the Unwind model, and is projected to have <u>$132 million more in LTD</u> at the end of 2013. While this is a mathematical consequence of the assumptions and methods underlying BREC's projections, at a reality level it should be very troubling to the Commission that BREC is planning to add $132 million in Long Term Debt at the same time its two largest customers are leaving the system.

Q. DOES THE STARK NATURE OF THE VARIANCES BETWEEN BREC'S PRIOR FINANCIAL MODELING AND ACTUAL RESULTS SUGGEST THAT THE COMMISSION SHOULD BE VERY SKEPTICAL REGARDING BREC'S PROPOSED USE OF A FORECASTED TEST PERIOD?

A. Yes. These variances between predicted and actual financial results should cause the Commission to be very skeptical about the forecasted test period proposed by BREC, in addition to the forecasted test period concerns addressed in Mr. Ostrander's testimony.

Excess Capacity and Fair, Just and Reasonable Rates

Q. BREC STATES THIS RATE CASE IS LARGELY DESIGNED TO RECOVER THE LOST MARGINS DUE TO THE DEPARTURE OF CENTURY ALUMINUM, WHICH BREC CALCULATES TO BE $63 MILLION.[41] SHOULD THE COMMISSION ALLOW BREC TO INCREASE RATES CHARGED TO THE RURAL AND LARGE INDUSTRIAL CLASSES TO RECOVER LOST MARGINS FROM THE CENTURY DEPARTURE?

A. No. The Unwind Transaction was a bargained-for exchange, including the Smelter Agreements. The smelters and BREC had a Commission-approved bargained-for

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[41] The Direct Testimony of Robert W. Berry on behalf of Big Rivers, Exhibit Berry 4 states a "Net Revenue Requirement Due to Century Exit" of $63,028,536. The calculation begins with "Century Gross Sales Margin (Revenue less Variable Cost)" of $92,397,332.

exchange regarding the terms, conditions and rates under which BREC would provide power to the smelters. The Commission should not allow BREC to now transfer lost margins from the smelters to remaining rural and large industrial consumers. These lost margins from the Century departure cover costs which are not appropriately assigned to other rural and large industrial consumers and which stem at least in part from plant which is no longer "used or useful" in providing public utility service. The rates proposed to be charged to remaining large industrial and rural consumers are not fair, just and reasonable since they include BREC's proposal to make these consumers responsible for paying costs of another customer--lost margins due to Century's departure. The Commission should not require remaining large industrial and rural consumers to be responsible for all costs on a residual basis, including the costs of excess capacity that result from consequences of the bargained-for agreement between BREC, Kenergy and the smelters—and a party which is no longer present - E.ON.

Q. DO YOU PROPOSE AN ADJUSTMENT TO THE REVENUE REQUIREMENTS PRESENTED BY BREC IN THIS CASE, TO ADDRESS THIS?

A. Yes, I recommend that the Commission remove the impact of "lost margins" from the departure of Century that is reflected in Mr. Ostrander's schedules as adjustment OAG-1-DB, which reverses BREC's proposed adjustment of $63,028,536.

Q. ARE THERE COMPONENT PARTS THAT CAN BE CALCULATED AND DEMONSTRATED IN SUPPORT OF THE REASONABLENESS OF NOT ACCEPTING RECOVERY OF LOST MARGINS DUE TO CENTURY'S DEPARTURE?

A. Yes. Mr. Holloway's testimony addresses the overstatement of transmission costs proposed by BREC to be recovered from remaining rural and large industrial consumers, including Alcan, in the amount of $10,760,729. This can be viewed as a component part of the $63 million proposed by BREC to be recovered from remaining consumers. Furthermore, BREC has identified costs of the Wilson plant remaining in the Forecasted Test Period, after the planned layup of the plant, as being **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** million.[42] Together these items total **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** million, which therefore explains most of the $63 million in "lost margins" that BREC proposes to recover from remaining rural and large industrial consumers.

Q. IS THE WILSON PLANT "USED OR USEFUL" IN PROVIDING PUBLIC UTILITY SERVICE TO REMAINING RURAL AND LARGE INDUSTRIAL CONSUMERS?

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[42] Big Rivers' Response to AG 1-107 (Confidential).

A. No. BREC has demonstrated by its own actions in "laying up" the Wilson plant in response to the Century departure that Wilson is not "used or useful" in the provision of utility service. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** The Commission should not burden ratepayers with the cost of plant and operations which are not used or useful. BREC has removed some of the cost of Wilson plant via expense adjustments to recognize its planned "lay-up", but **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** million remains in proposed revenue requirements,[43] as follows:

Depreciation	$20.031
Interest Expense	$22.544
Property Tax	$1.084
Property Insurance	$1.209
Fixed Departmental Expense	[redacted]
Labor/Labor Overhead	$1.579
Total Test Period	[redacted]

Q. IS IT REASONABLE TO INCLUDE THESE COSTS OF THE IDLED WILSON PLANT IN REVENUE REQUIREMENTS IN THIS CASE?

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[43] *Id.*

A. No. The Commission should exclude these costs from ratemaking in this matter. The Commission may elect to exclude these costs either directly via an adjustment in this amount or via inclusion in the higher level adjustment of $63 million to reverse BREC proposed "lost margins" adjustment to account for Century's departure from the system. Century's departure leaves BREC with considerable excess generating capacity, and BREC plans to address this excess capacity issue by laying up the Wilson plant and/or other generating plant **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. BREC states in response to PSC Staff 2-21(c) the "current long-term Financial Model indicates Wilson Station will restart in 2019." However it is crucial to recognize that this considers <u>only</u> the Century departure, and with the impending Alcan departure, the restart of Wilson Station would obviously extend further into the future, all other things equal. Furthermore, the Wilson lay-up places it in a state where it is "unavailable for service" and it would take "weeks or months" to bring the unit back into service.[44] Wilson is not "used or useful" in utility service in its state of lay-up, and is unavailable for utility service in its state of lay-up. The Commission should not include the costs of plant which are not used and useful in providing public utility service in revenue requirements. Therefore, the Commission should

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[44] *Id.*, at page 6. Note also Big Rivers Response to AG 1-111 which states it will take 43 days to "restore [Wilson] from an idled status."

exclude costs of the idled Wilson plant from revenue requirements in this proceeding as being excess capacity - plant which is not used or useful in the provision of public utility service. This is necessary to achieve fair, just and reasonable rates.

Q. DOES THE PUBLIC QUESTION WHY ITS RATES MUST INCREASE TO RECOVER COSTS OF PLANT WHICH IS NOT USED OR USEFUL (OR EXCESS CAPACITY), SUCH AS THE COSTS OF THE WILSON PLANT?

A. Yes. One member of the public has directly questioned the recovery of the shortfall caused by Century's departure from all other ratepayers instead of reducing capacity, as follows:

> "Why would BREC need to maintain its facilities at or near the same capacity as they have now?"[45]

> "It seems, logically, that BREC should be able to reduce operating costs by scaling back operations related to the Century power-generating, and that that reduction of operating costs would offset the vast majority of the 'lost revenue' from Century's business."[46]

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[45] Attachment to Big Rivers Response to KIUC 2-43, page 11.

[46] *Id.*, page 4.

This observation from the public is accurate, and is addressed by the removal of costs related to the idled Wilson plant as proposed in my testimony.

Q. WILL THE RATES PROPOSED BY BREC IN THIS CASE NECESSARILY RECOVER BREC'S CALCULATED DEFICIENCY?

A. No, the proposed rates will not necessarily recover the calculated deficiency. It is a given that a noticeable change in price will change the quantity of a product or service demanded by consumers. This is known as price elasticity of demand. BREC has proposed a significant increase in price, and this price increase should be expected to reduce demand. BREC takes the position that "the price elasticity coefficient that was factored into the 2011 Load Forecast results in demand and energy sales reductions that are reasonable for the forecasted test period." But "the 2011 Load Forecast included price elasticity for residential customers on normal projected increases anticipated at the time, using a price elasticity coefficient of -0.26, but did not give consideration to customer consumption changes that may result from the specific rate increase proposed in this case."[47] Big Rivers states it "has not completed a study to determine whether the magnitude of the rate increase sought in this proceeding will result in demand and

[47] Big Rivers response to KIUC 1-35, emphasis added.

energy sales reductions that exceed those already included in the forecast."[48] BREC makes no mention of price elasticity of demand associated with the Large Industrial customer class. BREC has not demonstrated that the assumed price elasticity coefficient factored into the 2011 Load Forecast is appropriate for the magnitude of increases proposed in this case.

BREC's Mission

Q. WHAT IS THE MISSION OF BREC?

A. According to its website, "the mission of BREC is to safely deliver low cost, reliable wholesale power and cost-effective shared services desired by the members."[49] BREC states in its Application at page 2 that it "exists for the principal purpose of providing the wholesale electricity requirements of its three distribution cooperative member-owners."

Q. IS MAINTAINING EXCESS CAPACITY IN REVENUE REQUIREMENTS AND INCREASING RATES TO REMAINING CONSUMERS TO COVER THOSE COSTS CONSISTENT WITH BREC'S MISSION AS A COOPERATIVE?

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[48] Big Rivers response to KIUC 2-15a.

[49] http://www.bigrivers.com/default.aspx

A. No. BREC operates on a non-profit basis to serve its retail members. Maintaining excess capacity on the scale created by the departure of the smelters would cause BREC to more closely resemble a merchant generator than a cooperative serving its members. BREC's proposed lay-up of Wilson demonstrates that BREC has significant capacity in excess of what it needs for its "principal purpose of providing the wholesale electricity requirements of its three distribution cooperative member-owners."[50] As stated by Mr. Berry at page 5, BREC currently owns and operates 1,444 MW of net generating capacity in four stations:

- Coleman Station – 443 MW
- Reid Station – 130 MW
- Green Station – 454 MW
- Wilson Station – 417 MW

Century currently utilizes 482 MW, and Alcan currently utilizes 368 MW, for a total of 850 MW.[51] The smelter load represents 59% of BREC's net generating capacity. The smelters provide 64% of BREC's wholesale revenue—Century is the source of approximately 36%, and Alcan is approximately 28% of wholesale

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[50] **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]**

[51] Direct Testimony of John Wolfram on behalf of Big Rivers Electric Corporation, at page 6, line 11.

revenues.[52] BREC proposes to require consumers to pay the costs of maintaining excess capacity created by the departure of the smelters while it searches for replacement load in a depressed market for power. The Commission should not allow BREC to place its members or their customers in the position of paying for excess capacity for an indeterminate time period with uncertain results.

Q. IS BREC CHARGING ITS MEMBERS ONLY FOR THE COSTS OF POWER RECEIVED UNDER THE MEMBERS' "ALL REQUIREMENTS" CONTRACTS?

A. No. BREC is proposing to charge its members for the costs of excess capacity which is not necessary for the provision of power to the members. The provision of "all requirements" for power to the members is being inverted by BREC to payment of all BREC's costs by the members. The "all requirements" concept should not be expanded to flow through all costs of BREC's excess capacity to its members.

Q. SHOULD REMAINING RURAL AND LARGE INDUSTRIAL CONSUMERS BE REQUIRED TO BEAR THE COSTS AND RESULTS OF BREC'S DECISION TO PROCEED WITH THE UNWIND TRANSACTION (IN THE FORM OF THE COSTS OF EXCESS CAPACITY)?

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[52] Big Rivers response to AG 2-37 and to PSC 3-9, Corrective Plan provided to RUS, attachment 1, page 2.

A. No. This is a primary question for the Commission to consider—who should bear the risk of BREC's decision to pursue, negotiate and agree to the Unwind transaction? "BREC viewed this proposal [E.ON's proposal for BREC to take back operational responsibility] as an opportunity to improve its financial position for the benefit of itself and its members, as a means to obtain financing on more favorable terms, and as a way to better manage its long-term power supply."[53] However, this view of BREC turned out rather quickly to have been very wrong. The Commission should not burden remaining consumers with the excess capacity costs caused by the smelters departure based on BREC's decision to pursue, negotiate and agree to the Unwind transaction. In the Unwind transaction, BREC re-acquired substantial long term and fixed obligations in plant assets and debt in part to serve a substantial but intermediate-term load of the smelters. This mismatch between BREC fixed assets and obligations versus remaining customer load should not be addressed by burdening remaining ratepayers with the carrying costs of the excess fixed assets. It should be addressed by reducing the scale of BREC's operations.

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[53] Unwind Order, page 7.

Q. DOES THE SMELTERS' TERMINATION OF THE SMELTER AGREEMENTS PROVIDE BREC WITH AN OPPORTUNITY TO REDUCE THE SCALE OF ITS OPERATIONS?

A. Yes, termination of the smelter agreements provides BREC with both the opportunity and the necessity of reducing the scale of its operations. BREC is at a major fork in the road. It has chosen to file rate cases to burden remaining consumers with the costs of excess capacity caused by termination of the Smelter Agreements. The other path is to work directly on reducing the excess scale of operations that is causing the excess capacity costs. It is very likely (given the large size of the smelter load) that the rate increase path will end up at the excess scale reduction path, only at a later date. BREC should not dissipate reserve funds during pursuit of rate increases and replacement load when such an approach cannot generate materially beneficial results for at least 3-4 years. Reserve funds would be best and most appropriately used at this juncture to support a transition while BREC is taking concrete steps to reduce its scale of operations.

Disallowance of Costs of Excess Capacity

Q. ARE YOU AWARE OF OTHER CASES IN WHICH A STATE UTILITY COMMISSION HAS NOT INCLUDED GENERATING PLANT COSTS OR EXPENSES IN A G&T COOPERATIVE'S REVENUE REQUIREMENTS DUE

TO EXCESS CAPACITY, CONCERNS REGARDING EXCESSIVE RATES, AND "USED OR USEFUL" REGULATORY POLICY?

A. Yes, I am aware of two instances. First, the Kansas Corporation Commission found it necessary to disallow a portion of the generation plant for Sunflower Electric Cooperative due to these concerns. Sunflower sought to include a generating station financed by REA (predecessor to RUS) in rates to be charged to its eight retail members in Western Kansas, and the KCC disallowed a substantial portion of that generating plant for ratemaking purposes. Sunflower had negotiated a Deferral Plan with REA under which the Holcomb Unit would be phased in to rate base. Sunflower and REA's Deferral Plan "contemplated 50% of Holcomb in rate base the first year, and an additional 10% of Holcomb each succeeding year until the entire plant was in rate base after the sixth year."[54] Sunflower filed a rate case in 1984 to request 60% of Holcomb be placed into rate base. The Commission stated it would "evaluate each rate case on its own merits and allow such further portion of the Holcomb Unit to be placed into rate base <u>as can be justified on the basis of usage, economics, rate impact, price elasticity, off</u>

[54] *In the Matter of the Application of Sunflower Electric Cooperative, Inc., for approval of the State Corporation Commission to make certain changes in its charges for sale of electricity to its member cooperatives;* Docket No. 143,069-U, Order (April 2, 1985) at page 6. Hereafter referred to as the "Sunflower Rate Case Order." A full copy of this Order is included with my testimony as Exhibit DB-3.

system sales, peak requirements, carrying costs and load growth."[55] Facing circumstances very similar to those faced currently by this Commission, the Kansas Corporation Commission determined "the appropriate percentage of the Holcomb Unit to include in rate base, ... evaluat[ing] Sunflower's total generating capacity, firm purchase and sales, reserve requirements, system demand and performance criteria."[56] The KCC allowed 57% of the Holcomb Unit into rate base and disallowed the remainder based on the excess capacity not being "currently used and required to be used" and concerns that excessive rates to residential and industrial customers would result.[57]

Second, the Kentucky Public Service Commission in Case No. 9613 refused to allow recovery of Wilson-related debt expenses. [58] I am familiar with that case only by reference and review of the Order dated March 17, 1987. However, it appears from the Commission's 9613 Order that issues similar to those being considered in this matter -- including but not limited to the issues of off-system sales, Big Rivers' precarious financial position and debt leverage, excess capacity and the used and

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[55] Sunflower Rate Case Order, page 6, emphasis added.

[56] *Id.*, page 7.

[57] *Id.*, page 13-14.

[58] *In the matter of Big Rivers Electric Corp.'s Notice of Changes in Rates and Tariffs for Wholesale Electric Service and of a Financial Workout Plan,* Case No. 9613, Order (March 17, 1987). A full copy of this Order is included with my testimony as Exhibit DB-4. See also Case No. 9887, Order dated Aug. 10, 1987.

useful nature of the Wilson plant, and the allocation of risk between Big Rivers' creditors and ratepayers - were considered by the Commission. Also considered in the Commission's 9613 Order was the similarity of Big Rivers' circumstances to those of Sunflower Electric Cooperative.[59] Otherwise, the record will speak for itself.

Q. WHAT IS THE IMPORTANCE OF COMMISSION ACTION AS RECOMMENDED BY THE TESTIMONY ON BEHALF OF THE ATTORNEY GENERAL IN THIS MATTER?

A. Unless the Commission acts as recommended by our testimonies, the Commission can expect more of the same in the future with a repeat of history. The Commission can expect continued rate increase requests from BREC as the preferred means of dealing with its "precarious financial position." At this time there is no end in sight to what promises to be multiple rate cases and financing applications in the future, for the reasons expressed in this testimony, especially due to the extended time period and uncertainty associated with replacing the smelter load under BREC's proposed approach. The lost smelter load is too big to replace, and BREC therefore must take material and concrete steps to reduce the scale of its operations. BREC operations include excess capacity given the

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[59] *Id.*, at p. 17.

departure of the smelter load, and the Commission should require BREC to deal with this circumstance directly rather than subject remaining consumers to paying rates which are not fair, just and reasonable for an extended and uncertain time period to support what in essence is a merchant generation operation in a depressed market for power. This will require that BREC work with its lenders, the Commission and potential buyers to reduce the scale of its operations.

Q. IS THERE A LIKLIHOOD THAT THE FACTS AND CIRCUMSTANCES UPON WHICH THIS RATE CASE IS PRESENTED COULD MATERIALLY CHANGE?

A. Yes. The facts and circumstances changed almost immediately after the BREC filing with the second smelter - Alcan - providing its Notice of Termination to BREC two weeks after the rate case was filed. Also, it is not yet certain the particular generation resources MISO will determine are needed for system reliability. BREC has asked MISO to study "the reliability impacts related to a potential change of status" of Wilson, and the Coleman units, separately.[60] Results of these studies along with other factors such as whether the smelters obtain power from the market will be used by BREC to determine what generating capacity to idle. BREC has presented this case with the assumption that Wilson will be idled,

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[60] Big Rivers Response to PSC Staff 2-21, Attachments 1 and 2.

but that may be subject to change based on these results and further analysis by BREC and MISO.

But even more fundamentally the facts and circumstances of the case and its future test period would change with the recently announced agreement between BREC, Kenergy and Century whereby Century would be allowed to access market based power through Kenergy, for Century's operations and its to-be-acquired Rio Tinto Sebree operations.

Q. HAVE YOU REVIEWED THE ACTUAL AGREEMENTS AMONG CENTURY, BREC AND KENERGY FOR THE NEW ARRANGEMENT FOR ACCESS TO MARKET BASED POWER?

A. No, I have not had the opportunity to review those agreements as they have not been provided in this case. Also, I understand the Attorney General was not a party to any negotiations in this regard.

Q. DOES THIS APPARENT DEVELOPMENT REQUIRE ANY CHANGES TO YOUR TESTIMONY?

A. No. I have no facts to address this apparent development beyond the press reports. Therefore, I am obliged to address BREC's case as filed. One could speculate as to the impacts of this as yet not-provided set of agreements and whether or not BREC still really needs its requested $74 million but I will not do so in this testimony without documented facts.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION, INC. FOR AN ADJUSTMENT OF RATES	)))	Case No. 2012-00535

AFFIDAVIT OF DAVID BREVITZ

State of Kansas)

David Brevitz, being first duly sworn, states the following: The prepared Pre-Filed Direct Testimony, and the Schedules and Appendix attached thereto constitute the direct testimony of Affiant in the above-styled case. Affiant states that he would give the answers set forth in the Pre-Filed Direct Testimony if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, his statements made are true and correct. Further affiant saith not.

David Brevitz
David Brevitz

SUBSCRIBED AND SWORN to before me this 14th day of May, 2013.

David Linderman
NOTARY PUBLIC

My Commission Expires: 1-24-17

David Linderman
NOTARY PUBLIC~STATE OF KANSAS
MY APPT EXP: 1-24-17

Exhibit DB-1

David Brevitz, C.F.A.
Brevitz Consulting Services
3623 SW Woodvalley Terrace
Topeka, Kansas 66614

General

Mr. Brevitz is an independent regulatory consultant, a Chartered Financial Analyst and has more than thirty years of experience in state regulation of public utilities, regulatory policy at the state commission level, determination of revenue requirements in state regulatory proceedings, various telecommunications matters including telecommunications cost allocations and revenue requirements, and telecommunications regulation/de-regulation. Mr. Brevitz's consulting practice focuses on technical assistance to state utility commissions, consumer advocate offices and organizations, state attorneys general offices, and international telecommunications regulatory bodies.

Professional Designation and Community Service

Mr. Brevitz has achieved designation as Chartered Financial Analyst from the CFA Institute (formerly the Institute of Chartered Financial Analysts) in 1984. The CFA Institute is the organization which has defined and organized a body of knowledge important for all investment professionals. The general areas of knowledge are ethical and professional standards, accounting, statistics and analysis, economics, fixed income securities, equity securities, and portfolio management.

Mr. Brevitz is current President and previous Treasurer (2007 to 2010) of the Kiwanis Club of Topeka. He has served numerous terms on the Board of Directors of the Club, has been recognized by Kiwanis International as a George F. Hixson Fellow, and has his name inscribed on the Kiwanis International Foundation Tablet of Honor.

Recent Relevant Experience

- **March 2012 to Current, Kansas Statewide Broadband Initiatives, Department of Commerce**: Mr. Brevitz is assisting the Kansas Department of Commerce's Kansas Statewide Broadband Initiative's Broadband Mapping effort under NTIA auspices. Mr. Brevitz is working with the University of Kansas's Data Access and Support Center, and providing expertise and assistance in the areas of broadband research and analysis, service provider relations, data collection, data validation and verification, best practices, and overcoming challenges and barriers.

- **March 2012 to November 2012, Rural Local Exchange Company Revenue Requirement Issues, Utah Office of Consumer Services**: Mr. Brevitz is assisting the OCS in examination of RLEC revenue requirement issues to ensure prudent use of Utah Universal Service Funds, and that by extension the UUSF statewide assessment is appropriate and cost based. Mr. Brevitz is reviewing and analyzing issues such as employee and officer compensation issues; allocations between regulated and non-regulated operations; affiliate and related party transactions; implications and impacts of the FCC's Mega-Order on intercarrier compensation and the Federal Universal Service Fund; and appropriate treatment of expenditures for Fiber to the Home programs.

- **August 2011 to Current, Utilities Division Staff, Kansas Corporation Commission**: Mr. Brevitz is assisting KCC staff and the Commission in assessing policy and financial impacts on Kansas rural Local Exchange Carriers, larger Price Cap carriers and Kansas consumers of the FCC's actions regarding the Federal Universal Service Fund and Intercarrier Compensation, which culminated in the FCC's November 18, 2011 Report and Order. Mr. Brevitz is also evaluating revenue requirement and policy issues pertaining to rural Local Exchange Carriers of management compensation, use of RUS loan funds for Fiber to the Home, how Kansas Universal Service Funds are expended, and questions regarding RLEC affiliates and subsidiary relationships. Mr. Brevitz is also analyzing broadband deployment in Kansas through the FCC Form 477 data filed by each service provider in the state twice a year.

- **October 2011 to December 2011, Vermont E911 Board**: Mr. Brevitz performed an analysis of Vermont rural local exchange carrier and FairPoint Communications tariffs and charges for E911 service elements to the Vermont E911 Board, as compared to tariffs and charges for the same elements in the remaining 49 states. The analysis was provided in a Report which identified "best practices" in E911 tariffing and charges, and estimated the cost savings to the Vermont E911 Board and Vermont citizens from adopting these best practices.

- **July 2010 to February 2011, Project Leader, Florida Statewide Strategic Broadband Planning**: Mr. Brevitz led the Public Utility Research Center project team to study government use of broadband capabilities, study assets and services used by government in Florida for broadband capability, and recommend options for the State of Florida to optimize use of government fiber optic and other assets, from a State of Florida enterprise perspective, for current and future broadband capabilities needed by governmental entities. The project culminated in the report on "Strategic Planning for Florida Governmental Broadband Capabilities" containing analysis and options provided to Florida policymakers, available at:

  http://bear.warrington.ufl.edu/centers/purc/docs/papers/1111_Brevitz_Strategic_Planning_for.pdf

- **July 2009 to Current, PURC Senior Fellow**: Mr. Brevitz has been designated as a Senior Fellow by the Public Utility Research Center at the University of Florida. This designation is reserved for knowledgeable and experienced professionals who foster strong ties to academia, industry, and government, who embody PURC's values of respect, integrity, effectiveness and expertise, and who support PURC's mission to contribute to the development and availability of efficient utility services through research, education, and service.

- **February 2010 to Current, Statewide Toll Free Calling Plan Proposal**: Mr. Brevitz is assisting AARP in review of the proposed Statewide Toll Free Calling Plan rules before the Oklahoma Corporation Commission to draft and provide comments on the proposed rules on behalf of AARP. The proposed rules would significantly change intrastate intercarrier compensation (including elimination of access charges), eliminate long distance charges on consumers' bills (including Wide Area Calling Plans), revise facilities and signaling arrangements, and implement a telephone number based assessment methodology.

- **March, 2008 to Current, FairPoint Communications Financial Monitoring docket:** Mr. Brevitz is assisting the Maine Office of Public Advocate before the Maine Public Utilities Commission in Docket No. 2008-108 in monitoring compliance by FairPoint with financial and other commitments required by the PUC's conditional approval of the Verizon/FairPoint transaction. Mr. Brevitz is also assisting OPA in other matters that arise from time to time pertaining to FairPoint, such as request for waiver of provisions of FairPoint's Performance Assurance Plan, and particularly operational and service quality problems caused by lack of proper performance of FairPoint's new Operational Support Systems (OSS), other back office systems and supporting business practices.

- **September 2006 to Current, Nevada Office of Attorney General, Bureau of Consumer Protection, Various Telecommunications Regulatory and Cost Recovery Plans**: Mr. Brevitz is providing assistance to the Bureau of Consumer Protection regarding telecommunications matters generally, which include legislative proposals, merger and acquisition proposals, requests to increase rates for basic services, performance measurement and incentive plans, proposals to reclassify individual services as discretionary or competitive, proposals to introduce new services, requests to be designated as an Eligible Telecommunications Carrier (ETC), and other matters.

- **October 2009 to January 2011, FairPoint Communications Bankruptcy Proceeding**: Mr. Brevitz assisted the Maine Office of Public Advocate regarding the bankruptcy filing by FairPoint Communications in the US Bankruptcy Court (NY, NY). Mr. Brevitz reviewed filings by the company and parties to the proceeding, as well as financial and operational information pertaining to FairPoint's proposed reorganization.

- **1999-Current, Kansas Corporation Commission Advisory Staff:** Mr. Brevitz is serving as advisor to the Commissioners on a variety of telecommunications technical and policy matters. Mr. Brevitz also served as advisor on electric industry matters, including cases involving structure/restructure of Westar Energy and Aquila.

- **March 2009 to June 2009, Nevada Office of Attorney General, Bureau of Consumer Protection**: Mr. Brevitz assisted the BCP in its review and assessment of AT&T Nevada's Performance Measurement Plan and related Performance Incentives Plan, and changes proposed by AT&T to the Plans. The Plans are designed by the Commission to be self-executing and to encourage competition and discourage discriminatory conduct.

- **February 2009 to June 2009, USAID Capacity Assessment and Development for the Department of Public Services Regulatory Commission of Armenia:** Mr. Brevitz was team leader for the project to conduct a telecom sector strategic analysis, legal and regulatory assessment, and human and institutional capacity assessment for the PSRC in Armenia, under the auspices of USAID and the Academy for Educational Development. The team consisted of three experts from the US, and local experts in Armenia. The team delivered a comprehensive Final Report to AED and USAID on May 31, 2009, which addressed government's plan for IT sector development, market structure and technological potential, the current telecommunications law and regulatory environment, current regulatory performance and priorities, overlapping responsibilities, performance gaps, and human and institutional capacity assessment regarding

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areas including independence, accountability, transparency, institutional characteristics, organizational structure, and financing and budget.

- **February 2009, Presentation to 36th PURC Annual Conference**: Mr. Brevitz presented on the subject of "Telecommunications Competition: Where is it and Where is it Going?" The presentation at the Public Utility Research Center, University of Florida, assessed market structure and the competitiveness of telecommunications markets from a consumer perspective.

- **December 2008 to June 2009, Kansas Corporation Commission Staff:** Mr. Brevitz assisted the Kansas Corporation Commission Utilities Division staff in Docket No. 08-GIMT-1023-GIT in its assessment of Sprint Nextel's petition to the Commission to bring Embarq's intrastate switched access charges into parity with interstate rates. Mr. Brevitz filed testimony to assess Embarq's cost study in support of its intrastate switched access charges.

- **December 2008 to February 2010, Public Utilities Regulatory Authority of The Gambia:** Mr. Brevitz assisted the Public Utilities Regulatory Authority in The Gambia, under the auspices of the ITU, in the review of international wholesale and retail tariffs charged by the incumbent telecommunications company (GAMTEL) to mobile operators and retail customers to ensure that proposed rates are set at levels that are fair and not anticompetitive. Extensive individual consultations were held with stakeholders that culminated in further industry-wide consultations. In the course of this review, cost information for international wholesale and retail tariffs was reviewed and considered, retail rate benchmarking information was considered, the arrangement between GAMTEL and its affiliated mobile operator (GAMCEL) was reviewed vis-à-vis comparable arrangements with other mobile operators, and the results were provided in a consultative reports to PURA. Policy considerations based on enactment of the Information and Communications Act of 2008 were also addressed, especially including cost accounting and liberalization of the international gateway.

- **November 2008 to March 2009, Nevada Office of Attorney General, Bureau of Consumer Protection, Merger Application of Embarq and CenturyTel :** Mr. Brevitz provided assistance and testimony to the Bureau of Consumer Protection in the Embarq/CenturyTel merger case, addressing in filed testimony the subjects of financial viability, financial projections, debt leverage, synergies and customer benefits asserted to be associated with the proposed transaction. This case was resolved by stipulation among the parties.

- **November 2008, Presentation to NASUCA 2008 Annual Meeting**: Mr. Brevitz presented "Deregulation and Price Increases: the Hallmarks of a Competitive Market?" at the Annual Meeting in New Orleans, Louisiana, which addressed telecommunications market structure and the pattern of price increases following service deregulation.

- **May 2008 to September 2008, Unitil Corporation Acquisition of Northern Utilities**: Mr. Brevitz is working on behalf of the Maine Office of Public Advocate to address the financial, structural and transactional aspects of Unitil Corporation's proposed acquisition of NiSource's Northern Utilities gas distribution operations in Maine and New Hampshire, and also the Granite State Pipeline operation. Mr. Brevitz filed direct testimony containing recommendations and conditions designed to bring the proposed transaction to a level which would meet the "no net harm" standard for Commission approval of such transactions.

- **April – November, 2008, Maryland Office of People's Counsel, Verizon Alternative Regulation Plan**: Mr. Brevitz addressed the subjects of measurement and evaluation of telecommunications competition, how the level of competition has changed over the term of Verizon-Maryland's previous Alternative Regulation Plan, and the extent to which competition acts as an effective regulator in three rounds of prefiled expert testimony on behalf of the Maryland OPC in Case No. 9133 before the Maryland Public Service Commission. Mr. Brevitz used Verizon – MD data to construct a Herfindahl-Hirschman Index (HHI) which showed a highly concentrated duopolistic market structure, and an absence of effective competition. Mr. Brevitz evaluated the structure and impact on competition of Verizon's "Wholesale Advantage" program pertaining to CLECs subsequent to the demise of Unbundled Network Elements. Mr. Brevitz addressed many competition related subjects such as substitutability of services including VoIP, wireless and cable services; ILEC migration strategies; marketplace behavior under duopoly in contrast to "perfect competition" constructs; and ILEC claims regarding line losses and competition.

- **January, 2008 to January, 2009, Big Rivers Electric Corporation "Unwind" Transaction:** Mr. Brevitz worked for the Kentucky Attorney General (Office of Rate Intervention) to assess the Big Rivers and E.ON joint application to "unwind" a previous lease transaction. The 1998 transactions were part of Big Rivers' implementation of its bankruptcy reorganization, and included leasing Big Rivers' generating facilities to E.ON's predecessor for it to manage, operate and maintain; transferring responsibility to manage, operate and maintain two additional generating units owned by the City of Henderson (through Henderson Municipal Power & Light, or "HMPL"); purchasing by Big Rivers of a set amount of power at substantially fixed prices through a Power Purchase Agreement that it uses to serve the loads of its three member retail cooperatives; payment by LG&E Energy Marketing ("LEM") to the US Rural Utilities Service ("RUS") of monthly margin payments; and, providing a portion of two aluminum Smelters' power needs at substantially fixed rates through power supply contracts between LEM and predecessors of Kenergy. Various other proposed agreements and approvals are also to be addressed in this matter. Direct testimony was filed in this matter on behalf of the Attorney General of Kentucky's Office of Rate Intervention.

- **September 2007 - February 2008, Cable & Wireless/Barbados Price Caps**: Mr. Brevitz assisted the Fair Trading Commission and its staff in assessing the results of the first price cap plan for Cable & Wireless/Barbados, and in assessing the desirability of continuing a price cap for Cable & Wireless/Barbados, and related structural changes to better fit the revised price cap plan to current policies and conditions in Barbados. The assessment included consideration of actual financial results and future expected financial results and competitive conditions.

- **2007 to March, 2008, FairPoint/Verizon Merger/Acquisition of New England State Operations:** Mr. Brevitz worked on behalf of the Maine Office of Public Advocate to assess the proposed spin-off of Verizon operations in Maine, New Hampshire and Vermont and subsequent merger with and into FairPoint Communications, in a reverse Morris trust transaction. The assessment included evaluating financial projections of the company in support of financial viability of the proposed transaction; financial analyses associated with the proposed transaction performed by the company and investment advisors; and implications of resulting debt leverage and structure of the company as "high debt/high dividend". The testimony also included assessment of risk factors associated with the proposed transaction and FairPoint's operational execution risks. The Hearing Examiner's Report and the Commission's Final Order adopted Mr. Brevitz's financial recommendations including substantial debt and dividend reduction.

- **2007 to March, 2008, FairPoint/Verizon Merger/Acquisition of New England State Operations:** Mr. Brevitz worked on behalf of the New Hampshire Office of Consumer Advocate to assess the proposed spin-off of Verizon operations in Maine, New Hampshire and Vermont and subsequent merger with and into FairPoint Communications, in a reverse Morris trust transaction. The assessment included evaluating financial projections of the company in support of financial viability of the proposed transaction; financial analyses associated with the proposed transaction performed by the company and investment advisors; and implications of resulting debt leverage and structure of the company as "high debt/high dividend". The testimony also included assessment of risk factors associated with the proposed transaction and FairPoint's operational execution risks. The Commission made preliminary determinations in favor of Mr. Brevitz's financial recommendations, which were then reflected in the Commission's Final Order.

- **April 2007, PURC Advanced Training Course on Regulatory Economics and Process: Interconnection, Pricing and Competition:** Mr. Brevitz developed and presented three courses to members of the National Telecommunications Commission from Thailand. The courses covered accounting separation, case study on a rate proposal, and principles and practices for rate rebalancing.

- **January, 2007, 21st International Training Program on Utility Regulation:** Mr. Brevitz developed and presented training sessions on accounting separation, rate rebalancing (case study), and universal service obligations to the semi-annual training program for regulatory agency staff and commissioners worldwide. The training program is provided by the Public Utilities Research Center at the University of Florida in Gainesville.

- **2006-2008, Telecommunications Training for Regulatory Agency for Telecommunications (RATEL) in Serbia:** Mr. Brevitz assisted RATEL in implementation of new policies designed to open telecommunications markets in Serbia to competition. Issues being addressed include cost orientation of prices (rate rebalancing), universal service funds, interconnection, administrative procedures, internet telephony, and spectrum management.

- **2006-2007, Embarq UNE Loop Pricing Application:** Mr. Brevitz assisted the Bureau of Consumer Protection in the Nevada Attorney General's office in its assessment of Embarq's proposal to increase rates for the unbundled loop. This work included assessment of Embarq's proposed UNE loop cost model and its inputs, FCC orders which speak to TELRIC costing and UNE pricing, and use of the mapping program to support Embarq's proposed cost model.

- **"Assessing Pricing Behavior Under Deregulation"**: Presentation at the NASUCA Mid-Year Meeting, June 14, 2006, Memphis Tennessee.

- **2006 Spin-off of Windstream from Alltel**: On behalf of the Kentucky Attorney General (Office of Rate Intervention), Mr. Brevitz formulated discovery, and analyzed and addressed information relevant to the proposed spin-off of the local telecommunications operations from Alltel Corporation and subsequent merger with Valor Communications. Prefiled testimony was provided before the Kentucky PSC addressing the excessive debt burden placed on "SpinCo" by Alltel; conflicting company claims regarding merger synergies; lack of basis for claimed increased buying power; and non-arms-length nature of decisions and transactions in the proposed spin-off.

- **2005 Rate and Revenue Requirement Review of Saco River and Pine Tree Telephone Companies**: On behalf of the Maine Public Advocate's Office, Mr. Brevitz addressed revenue requirement levels for both companies, including detailed review of expense levels and trends, expanded calling plan criteria and data, and detailed review of holding company organization and charges between affiliates.

- **2005 Price Deregulation of Basic Local Exchange Service**: On behalf of AARP, Mr. Brevitz provided comments before the Public Utilities Commission of Ohio regarding final rules to implement procedures for addressing price deregulation applications. The comments addressed the need for effective competition to be demonstrated before approving price deregulation of BLES; market segmentation between stand-alone BLES and service bundles; barriers to entry; current competitive market conditions and whether "many sellers" exist; functionally equivalent and substitute services; and other related matters.

- **2005 Spin off of "LTD Holding Company" from Sprint Nextel**: On behalf of the Nevada Bureau of Consumer Protection, Mr. Brevitz led a team to analyze the proposed spin-off from a technical and public interest perspective under Nevada statutes. Issues addressed included: asset transfers to LTD Holding Co.; levels of debt to be placed on LTD Holding Co.; "normal" levels of debt for Sprint's Local Telecommunications Division; financial and cost of capital implications of the spin off; impact on LTD's ability to compete and other competitive trends; and accounting issues such as division of pension assets and pension liabilities.

- **"Telecommunications Convergence: On Duopoly?"**: Presentation at the NASUCA Mid-Year Meeting, June 15, 2005, New Orleans, Louisiana.

- **2005 Intrastate Deregulation Proposal of SBC Oklahoma**: On behalf of AARP, Mr. Brevitz filed testimony addressing SBC Oklahoma's proposal to deregulate pricing of almost all intrastate services (E911 and access services were excepted). The testimony responded to SBC Oklahoma assertions regarding significant retail competition on a widespread basis, openness of markets, barriers to entry and exit, reasonable interchangeability of use of cellular and VoIP services for basic residential services, market share analysis, and competitive trends including CLEC responses to the elimination of UNE-P, access line losses. The testimony further analyzed the actions, opportunities, and competitive responses of SBC Oklahoma and its corporate affiliates, observed public safety deficiencies of cellular and VoIP services, and market trends converging on duopoly.

- **2004 to 2005: Alternative Regulation Plan Filing by Verizon Vermont:** Mr. Brevitz assisted the Vermont Department of Public Service in assessing matters included in the Vermont Public Service Board's assessment of proposed changes to the Alternative Regulation Plan applicable to Verizon Vermont. Prefiled testimony addresses matters including assessment of competition and modes of competition, VoIP/wireless substitution, continuation of direct assignment practices under the FCC's separations freeze, jurisdictional cost allocations, rate flexibility, and UNE availability and commercial agreements with CLECs.

- **2005 UNE Loop Cost Proceeding**: On behalf of the Arkansas Public Service Commission General Staff, Mr. Brevitz filed testimony which analyzed SBC Arkansas' proposed increased UNE loop rates, and UNE loop model and shared and common cost model inputs and outputs, including fill factors, defective pairs, IDLC, DSL expenses, and retail related costs.

- **2004 Mass Market Switching Reviews under the FCC Triennial Review Order**: Separately for the Arkansas Public Service Commission staff, and the New Mexico Attorney General's office, Mr. Brevitz provided analysis and two-step evaluation under the FCC's Triennial Review Order ("TRO") of impairment in access to local circuit switching for mass market customers. The evaluations were done on a granular, market-specific basis. The evaluations determined whether unbundled local circuit switching (and by extension, the UNE-Platform) must continue to be provided as an Unbundled Network Element by incumbent local exchange companies.

- **2004 OSIPTEL/Peru**: Worked with OSIPTEL (telecom regulator in Peru) to analyze barriers to competition in Peru. Presented workshop and training materials regarding the Economic Aspects of Competition Regulation for Public Utilities, which addressed concepts of market power, dominance, cross subsidies, essential facilities, ex ante versus ex post regulation, asymmetric regulation.

- **2003 to 2005: Cable & Wireless Rate Adjustment/Barbados Fair Trading Commission**: Mr. Brevitz advised the FTC and its staff regarding the application of C&W Barbados to increase domestic revenues and institute local measured service, and providing related analyses. The Company's filing was in part designed to enable Price Cap regulation, and opening the market to competitors. As such, Price Cap and competitive issues were necessarily considered along with revenue requirements and tariff/pricing issues.

- **2003 CenturyTel Rate Case/Arkansas PSC:** Mr. Brevitz led a team providing analysis and testimony on behalf of PSC staff in the CenturyTel of Northwest Arkansas rate case, in which the Company sought to treble local rates. Mr. Brevitz provided an analysis of CenturyTel of Northwest Arkansas' ("CNA") modernization programs and provision of DSL services from the perspective of basic local service ratepayers, and also addressed the local competition claims of the Company.

- **2002 Maryland Office of People's Counsel:** Maryland PSC's Case No. 8918 is to review Verizon's Price Cap regulatory plan, after Verizon had operated five or more years under it. Topics addressed included the proper productivity factor to use in the price Cap formula, and any necessary amendments to the structure of the price cap plan. Mr. Brevitz provided expert testimony on the proper formulation and terms for the price cap formula, competition, and other matters related to the extension of price cap regulation.

- **2001 Maine Office of Public Advocate–Verizon Maine 271 Review:** Review of Verizon's Section 271 filing before the Maine Public Service Commission, and Declaration filed on behalf of the Public Advocate which addresses Checklist Item #13 (Reciprocal Compensation), and Verizon's proposed performance measurement metrics and proposed Performance Assurance Plan.

- **2001 Vermont Department of Public Service–Verizon Vermont 271 Review:** Review of Verizon's Section 271 filing assertions of compliance with the "14 Point" competitive checklist and non-discrimination obligations of the Telecommunications Act of 1996, before the Vermont Public Service Board. Mr. Brevitz filed a Declaration on behalf of the DPS which addresses Checklist Item #13 (Reciprocal Compensation), and Verizon's proposed performance measurement metrics and proposed Performance Assurance Plan. Mr. Brevitz's work continued on behalf of the Department in Docket No. 6255, which worked through a series of workshops to evaluate appropriate carrier-to-carrier standards for use in Verizon-Vermont's territory, resulting in a stipulation approved by the Public Service Board.

- **2001 Public Utility Research Center (PURC)/University of Florida:** Presentation of two seminar modules and an interconnection case study as staff training for the Panamanian telecommunications regulatory body, ERSP. Mr. Brevitz developed course content and presentation materials for the seminar, under the auspices of PURC, on the topics of the "US Experience in Telecom Competition" and "Consumer Issues in Telecom Competition". These topics were presented by Mr. Brevitz in the seminar at Panama City, Panama on March 29-30, 2001.

- **2001-2002 Michigan Attorney General's Office–Federal District Court Litigation Support**: Mr. Brevitz supported the Attorney General's office in its defense of lawsuits by Ameritech and Verizon against the PSC and the Governor regarding recently passed state legislation. The state legislation eliminated the intrastate EUCL being charged by both companies, expanded local calling areas, and froze the application of the Price Cap Index for a period of time.

- **1999-2000 Delaware Public Service Commission Staff–Evaluation of Bell Atlantic-Delaware's Collocation Tariff Filing:** On behalf of the Staff, Mr. Brevitz reviewed BA-Delaware's Collocation tariff filing, and prefiled testimony on behalf of Delaware PSC staff. Issues addressed include non-discriminatory provisioning of collocation; collocation intervals; utilization of "best practices" for terms, conditions and pricing; and costing.

- **1999-2000 Vermont Department of Public Service–Evaluation of Carrier to Carrier Wholesale Quality of Service:** On behalf of the Vermont DPS, Mr. Brevitz was engaged in the review of quality of service standards related to Verizon's wholesale activities of provisioning Unbundled Network Elements and resold services. The work effort was conducted within a workshop of the parties, and was drawn on the similar activity for BA-NY and a number of other states including Massachusetts and Virginia. Measures, standards and benchmarks were to be determined, along with an appropriate remedy plan in the event those items are not met by the incumbent carrier. This matter was resolved in the context of Verizon's Section 271 case.

- **1999-2000 Vermont Department of Public Service–Investigation of Geographically Deaveraged Unbundled Network Prices:** On behalf of the Vermont DPS, Mr. Brevitz testified before the Vermont Public Service Board regarding the appropriateness and extent of geographic deaveraging of rates for Unbundled Network Elements (UNEs) in Vermont. In formulating these positions, it was necessary to consider FCC Orders, competitive policy implications, and related issues such as distribution of federal high cost support. The FCC had spotlighted the linkages between high cost support and geographic deaveraging determinations. Consequently the testimony also considered federal high cost support distribution implications and local rate impacts stemming from geographic deaveraging determinations to be made by the Board.

- **1999 Vermont Department of Public Service–Evaluation of Bell Atlantic Proposed Alternative Regulation Plan, Wholesale Quality of Service Standards, and Cost of Service:** Mr. Brevitz served as project manager and lead consultant in the DPS review of Bell Atlantic's proposed Price Point Plan and proposed appropriate modifications. Those modifications included moving rate reductions forward to the inception of the plan, and aligning the plan more closely to the status of competition in Vermont by allowing streamlined regulation only for truly new services, not bundles of existing services. Mr. Brevitz also supported the immediate implementation of detailed wholesale quality of service standards along with a remedies structure. Mr. Brevitz addressed the cost of service issues of reciprocal compensation and local number portability, and proposed rate design changes to effect the return of $16 million in excess revenues.

- **1998-99 Delaware Public Service Commission Geographic Deaveraging of Bell Atlantic UNE Loop Rates:** Mr. Brevitz worked for PSC staff to analyze cost and policy issues associated with geographic deaveraging of UNE loop rates. Methodology and policy to determine geographic zones was reviewed for BA-Del, and compared to all other Bell Atlantic states. BA-Del cost data was reviewed to assess closeness of fit between BA-Del's proposed population of zones with existing exchanges to the loop costs of those exchanges. After review of comments of interested parties, Mr. Brevitz prepared and submitted a report and recommendation to the PSC regarding modification of BA-Del's proposal to implement geographically deaveraged UNE loop rates. The PSC adopted the report and recommendation in its Order in the matter.

- **1998 Vermont Department of Public Service- Evaluation of Proposed Special Contracts for Toll and Centrex Services for Compliance with Imputation Requirements:** Mr. Brevitz worked for the DPS in this matter, which was an evaluation of four individual customer toll contracts, and two individual customer Centrex contracts, under the Vermont Public Service Board's price floor and imputation requirements. This evaluation included analysis of whether Bell Atlantic had appropriately followed the Board's imputation requirements; whether the imputed costs had been appropriately calculated and included all relevant costs; and, whether undue price discrimination would result from approval of Bell Atlantic's proposed prices. Mr. Brevitz analyzed the Company's filed testimony and costing information provided in support of the contract pricing; drafted staff discovery and analyzed responses of other parties in the matter; and, supported pre-filed rebuttal and surrebuttal testimony before the Board under cross examination. Hearings in this matter were held in November and December of 1998 and January 1999.

- **1998 Delaware Public Service Commission- Re-classification of Residential ISDN as "Competitive":** Mr. Brevitz worked for Delaware Public Service Commission staff in this case (Docket 98-005T), which was a filing by Bell Atlantic to move Residential ISDN ("R-ISDN") from the basic service classification to the competitive service classification, pursuant to the Telecommunications Technology Investment Act and related Commission rules to implement the Act. Bell Atlantic filed an application before the PSC stating that R-ISDN met the statutory and rule conditions for moving the service to the competitive class of services, along with market information in support of that statement. Mr. Brevitz analyzed the company's filing and the comments of other parties in the matter from an economic and public policy perspective, analyzed the Company's compliance with applicable provisions of the TTIA and Commission rules, drafted staff discovery and analyzed discovery responses of other parties, and presented testimony under cross examination before the Commission. The hearing in this matter was held July 9, 1998.

- **1997 Delaware Public Service Commission - Costing and Pricing of Residential ISDN Service:** Mr. Brevitz assisted the Delaware PSC staff in this case (Docket 96-009T) by reviewing the prefiled testimony of all parties; reviewing the cost studies supporting Bell Atlantic's proposed R-ISDN pricing; comparing those costs to Bell Atlantic's UNE rates and costs; reviewing Bell Atlantic's contribution analyses and demand forecasts for the R-ISDN service; reviewing and comparing two Bell Atlantic local usage studies (the second of which more than tripled the costs of the earlier study); providing an analytic report on the usage cost studies to PSC staff and rate counsel; assisting in the preparation and conduct of cross-examination; and assisting staff rate counsel in preparation of the brief in this matter. The hearing in this matter concluded in January 1998.

- **1997 Georgia Public Service Commission - Unbundled Network Elements Cost Study Review:** Mr. Brevitz was a lead consultant in this engagement. The GPSC opened a cost study docket to determine the cost basis for BellSouth UNE rates, following arbitration hearings involving BellSouth and several competitors. Introduced for the first time by BellSouth, and considered in the hearing was BellSouth's "TELRIC Calculator". Also considered in the hearing, as sponsored by AT&T/MCI was Hatfield Model Versions 3 and 4. Mr. Brevitz prepared and provided to GPSC staff an "Issues Matrix" which listed the issues, party positions on the issues, and a suggested staff position. Also on behalf of GPSC staff, Mr. Brevitz analyzed cost inputs and outputs pertaining to both models. No testimony was provided in this matter as GPSC staff did not testify in the hearing. Hearings on the matter concluded in September 1997.

- **1995, 1996 and 1997 Wyoming Public Service Commission - Competition Rules:** Mr. Brevitz was the Project Manager and a lead consultant for this engagement. Mr. Brevitz is actively involved in writing and implementing comprehensive competition rules in Wyoming which consider the new 1995 Telecommunications Act in Wyoming and the 1996 Federal Telecommunications Act. These rules address interconnection/unbundling, universal service, service quality, price caps/alternative regulation, privacy, resale, intraLATA dialing parity, TSLRIC/cost study methods; access charge rate design; number portability, reciprocal compensation, rights-of-way and other matters.

- **1995 and 1996 Wyoming Public Service Commission - U S WEST Pricing Plan:** Mr. Brevitz was the Project Manager and a lead consultant for this engagement. Mr. Brevitz has evaluated and filed testimony regarding U S WEST's pricing plan, competition issues, universal service and U S WEST cost study issues.

- **1996 Oklahoma Corporation Commission - Seminar on 1996 Federal Telecom Act**: Mr. Brevitz presented a seminar on the 1996 Federal Telecom Act to the Oklahoma Corporation Commission Staff.

- **1995 and 1996 Georgia Public Service Commission - Local Number Portability and Competition Policy:** Mr. Brevitz was the Project Manager and a lead consultant for this engagement. Mr. Brevitz assisted the GPSC in implementing rules related to the new 1995 Telecommunications Act in Georgia and the 1996 Federal Telecom Act. Mr. Brevitz was primarily involved in initiating and coordinating the Number Portability Task Force and guiding the industry workshop on permanent number portability. The PSC has accepted the industry workshop recommendation. As a result, Georgia will be one of the first states to implement full number portability. Assistance was also provided on other competition issues.

- **1996 California Public Service Commission - Pricing of Unbundled Elements and Resale services:** Mr. Brevitz assisted Sprint in the pricing (second) phase of the California Commission's OANAD proceeding. Testimony was presented regarding proper pricing of unbundled network elements, ~~given previous a PUC decision on UNE costs. The cost (first) phase involved the~~ development of cost study principles, performance of TSLRIC cost studies of unbundled network elements by Pacific Bell and GTEC, and performance of avoided cost studies for retail services for resale.

- **1995 to 1996 Kansas Telecommunications Strategic Planning Committee - Kansas Corporation Commission:** Mr. Brevitz served as the Kansas Corporation Commission representative on this legislative committee, which was organized in mid-1994 to research and recommend any needed changes to the telecommunications statutes and state policies. The TSPC issued its final report to the Governor and the legislature in January 1996. Mr. Brevitz drafted the NTIA grant application for the Committee and worked with Legislative Research staff to draft the TSPC's Report to the Kansas Legislature. Mr. Brevitz also drafted subsequent reports to the Kansas Legislature regarding telecommunications on behalf of the KCC.

- **1995 Chairperson of Kansas Corporation Commission Working Groups:** Mr. Brevitz was appointed to the Cost Studies and Universal Service Working Groups for the KCC's general competition investigation, subsequent to the KCC's May 1995 Phase I competition order. He was also active in other Task Forces including Unbundling, Number Portability and Local Resale.

- **Kansas Corporation Commission - Infrastructure/Competition Report**: Produced a special report on Kansas telecommunications infrastructure/competition issues which was provided to the 1995 Kansas legislature.

- **1994 Kansas Corporation Commission - Alternative Regulation Legislation:** In 1994 the Kansas Legislature passed House Bill 3039, which extended SWBT's "TeleKansas" alternative regulation plan for two years. Mr. Brevitz provided substantial assistance in negotiating the detailed provisions for the KCC's implementation of the bill.

- **Kansas Corporation Commission - Southwestern Bell Telephone Infrastructure Analysis:** Investigated SWBT's infrastructure/modernization budget and addressed construction requirements, tariffs, rates, terms and conditions for SWBT's provision of interactive television ("ITV") to all Kansas schools at deep discount prices for the benefit of the Kansas infrastructure and schools.

Work History

Independent Telecommunications Consultant

Following a significant engagement with the Kansas Corporation Commission, extensive professional services have been provided to state public utility commissions, as indicated above under "Recent Relevant Experience".

A variety of duties and tasks have been performed for the Kansas Corporation Commission, including providing staff support for Statewide Strategic Telecommunications Planning Committee, composed of 17 members (legislators, state agency heads, private enterprise); assisting in KCC implementation of House Bill 3039 ("TeleKansas II", extension of alternative regulatory plan for Southwestern Bell Telephone); and providing analysis and testimony for communications general investigations into competition in the local exchange and other markets. Those general investigations included General Competition, Competitive Access Providers, Network Modernization, Universal Service, Quality of Service, and Access Charges.

Kansas Consolidated Professional Resources - Director of Regulatory Affairs

Duties included monitoring of and participating in state regulatory affairs on behalf of twenty independent local exchange companies in Kansas that compose the partnership of KCPR. Active participation in statewide industry committees in the areas of access charges, optional calling plans/EAS, educational interactive video, dual party relay systems and private line/special access merger.

Kansas Corporation Commission - Chief of Telecommunications

Duties included supervising the formulation of staff testimony and policy recommendations on matters such as long distance competition, access charges, telephone company rate cases, and deregulation of CPE and Inside Wiring; analyzing Federal Communications Commission and

Divestiture court decisions; supervising and performing tariff analysis; and testifying before the Commission as necessary. SWBT's $120 million "Divestiture rate case" was completed in this time period, as were several other large rate cases. Active member of the National Association of Regulatory Utility Commissioners (NARUC) Staff Committee on Communications.

Arizona Corporation Commission - Chief Rate Analyst - Telecommunications

Duties included supervision of staff and formulation of policy recommendations on telecommunications cases, along with production of analyses and testimony as required.

Kansas Corporation Commission - Economist - Research and Energy Analysis Division

Duties included research, analysis and production of casework and testimony regarding gas/electric and telecommunications matters. Matters addressed included revision of jurisdictional separations, deregulation of CPE and inside wire, Wolf Creek Nuclear Generating Plant Task Force, and divestiture of the Bell Operating Companies from AT&T.

Education

Michigan State University - Graduate School of Business
East Lansing, Michigan
Master's Degree in Business Administration-Finance.

Michigan State University/James Madison College
East Lansing, Michigan
Bachelor of Arts Degree in Justice, Morality and Constitutional Democracy.

Exhibit DB-2

RECEIVED

APR 03 2008

PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY
OFFICE OF THE ATTORNEY GENERAL

April 3, 2008

JACK CONWAY
ATTORNEY GENERAL

1024 CAPITAL CENTER DRIVE
SUITE 200
FRANKFORT, KENTUCKY 40601

Stephanie Stumbo
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40602-0615

Re: Case No. 2007-00455

Dear Mrs. Stumbo:

Please find attached the original and ten copies of the Attorney General's Testimony, Completely Unredacted, in the above matter. Because there are confidentiality agreements which control the exchange of material to varying degrees between the parties, I also provide the following breakdown of the Redacted Testimonies which have been filed with the Commission as well as the particular draft which each party will receive. The items listed below are filed under seal. In addition to the items below, a completely redacted public version has been filed which is the copy that the Member Cooperatives and Henderson will receive.

Item 1 Completely Unredacted Testimony

Item 2 E.ON U.S. Parties: Redacted Copy of Testimony

Item 3 Big Rivers: Redacted Copy of Testimony

Item 4 Smelters: Redacted Copy of Testimony

The basis for the "roadmap" employed for ascertaining the degree of disclosure resulted from a series of emails pursuant to my inquiry on the subject during the actual discovery phase of the case. It is the hope and the intent of the Attorney General that no inadvertent disclosure has occurred yet that all information publicly available has been filed and all parties have received their respective testimony.

Stephanie Stumbo, Executive Director
Kentucky Public Service Commission
April 3, 2008
Page 2

Should you have any question, feel free to contact me immediately. I thank you in advance for your attention to this matter.

Sincerely,

Dennis Howard, II
Acting Director
Office of Rate Intervention
Office of the Attorney General
502.696.5453

Attachments

RECEIVED

APR 03 2008

PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATIONS OF BIG RIVERS ELECTRIC CORPORATION FOR: (I) APPROVAL OF WHOLESALE TARIFF ADDITIONS FOR BIG RIVERS ELECTRIC CORPORATIONS, (II) APPROVAL OF TRANSACTIONS (III) APPROVAL TO ISSUE EVIDENCES OF INDEBTEDNESS, AND (IV) APPROVAL OF AMENDMENTS TO CONTRACTS; AND	)	CASE NO. 2007-00455
OF E.ON U.S., LLC, WESTERN KENTUCKY ENERGY CORP. AND LG&E ENERGY MARKETING INC. FOR APPROVAL OF TRANSACTIONS	)	

DIRECT TESTIMONY OF DAVID BREVITZ
ON BEHALF OF
THE ATTORNEY GENERAL

Certificate of Service and Filing

Counsel certifies that an original and ten photocopies of the foregoing Direct Testimony of David Brevitz On Behalf Of The Attorney General were served and filed by hand delivery to Stephanie L. Stumbo, Executive Director, Public Service Commission, 211 Sower Boulevard, Frankfort, Kentucky 40601; counsel further states that true and accurate copies of the foregoing were mailed via First Class U.S. Mail, postage pre-paid, to:

C. William Blackburn
Big Rivers Electric Corporation
P. O. Box 24
Henderson, KY 42420

David Brown
Stites & Harbison PLLC
1800 Providian Center
400 West Market St.
Louisville, KY 40202

Honorable John N. Hughes
124 West Todd St
Frankfort, KY 40601

Honorable Frank N. King, Jr.
Dorsey, King, Gray,
Norment & Hopgood
318 Second St
Henderson, KY 42420

Honorable Michael L. Kurtz
Boehm, Kurtz & Lowry
36 East Seventh St., Ste. 1510
Cincinnati, OH 45202

Honorable James M. Miller
Sullivan, Mountjoy, Stainback
& Miller PSC
P.O. Box 727
Owensboro, KY 42302-0727

Honorable Kendrick R. Riggs
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Louisville, KY 40202-2828

Honorable Allyson K. Sturgeon
E.On US Services, Inc.
220 West Main St.
Louisville, KY 40202

Honorable Melissa D. Yates
Denton & Keuler Llp
P. O. Box 929
Paducah, KY 42002-0929

Gary Osborne - President
International Brotherhood Of
Electrical Workers
Local Union 101
2911 W. Parrish Ave
Owensboro, KY 42301

Honorable Douglas L. Beresford
George F. Hobday, Jr.
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555 Thirteenth Street N. W.
Washington, DC 20004 1109

David Spainhoward
Big Rivers Electric Corporation
P. O. Box 24
Henderson, KY 42420

Honorable Don Meade
Priddy Cutler Miller & Meade
800 Republic Bldg
429 W. Muhammad Ali Blvd.

this 3rd day of April, 2008

Assistant Attorney General

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2007-00455

DIRECT TESTIMONY OF
DAVID BREVITZ ON BEHALF
OF THE KENTUCKY ATTORNEY GENERAL

April 3, 2008

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2007-00455

DIRECT TESTIMONY OF

DAVID BREVITZ

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is David Brevitz. My business address is 3623 SW Woodvalley Terrace, Topeka, Kansas.

Q. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am an independent consultant serving state regulatory commissions, Attorney General's Offices, and consumer organizations. I am testifying on behalf of the Attorney General of Kentucky.

Q. DO YOU HAVE SPECIFIC EXPERIENCE, EXPERTISE AND DIRECT KNOWLEDGE REGARDING THE SUBJECTS WHICH ARE CONTAINED IN YOUR TESTIMONY?

A. Yes. Most recently I have conducted several detailed and extensive analyses of proposed utility financial transactions and related utility regulatory policies, under the relevant laws in those states. Those transactions were, in sequence:

- The proposed spin-off of its wireline telephone division ("Embarq") by Sprint/Nextel, on a tax-free basis, which included incurrence of substantial new debt by Embarq, and payments and other transactions with Sprint/Nextel. Work and analyses was conducted on two separate cases—first on behalf of the Nevada Attorney General's Bureau of Consumer Protection, and also (later) as a member of the Kansas Corporation Commission's Advisory Staff. Both cases were resolved by stipulations.
- The proposed spin-off of Alltel's wireline telephone division ("Windstream"), and subsequent merger with Valor Communications in a reverse Morris Trust transaction on a tax-free basis, which included incurrence of substantial new debt by Windstream, and payments and other transactions including special dividends to Alltel. Work and analyses was conducted on behalf of the Attorney General of Kentucky's Office of Rate Intervention.

- The proposed acquisition by FairPoint Communications of Verizon's Northern New England operations (Maine, New Hampshire and Vermont) in a reverse Morris Trust transaction on a tax-free basis, which included incurrence of substantial new debt by FairPoint, and payments, Transition Services Agreement, development of back office systems "from the ground up" and other transactions including special dividends to Verizon. Work and analyses was conducted in two separate cases—on behalf of the Office of Public Advocate in Maine and the Office of Consumer Advocate in New Hampshire. The Hearing Examiner in Maine issued her report, subsequent to which a stipulation among many parties was reached. Similarly, a stipulation was reached in New Hampshire. Subject to conditions, this transaction closed on March 31, 2008.

Q. PLEASE STATE YOUR EXPERIENCE AND PROFESSIONAL QUALIFICATIONS.

A. My career has been in public utility regulation with an emphasis in telecommunications. My interest in public utility regulation began while studying at the Institute of Public Utilities in the Economics Department at Michigan State University. This program covered principles of public utility regulation, and addressed issues for telephone, gas and electric utilities. While at Michigan State, I earned an undergraduate degree in Justice, Morality and Constitutional Democracy from James Madison College (a residential college at MSU) and an MBA in Finance (1980). Since that time, I have worked on numerous matters for state utility commissions, consumer advocates, Attorneys General, and international regulatory bodies. A complete description of my background and experience is provided on Exhibit DB-1.

Q. DO YOU HAVE OTHER RELEVANT QUALIFICATIONS?

A. Yes. In 1984 I was designated as a Chartered Financial Analyst by the Institute of Chartered Financial Analysts ("ICFA"). The ICFA is the organization which has defined and organized a body of knowledge important for all investment professionals. The general areas of knowledge are ethical and professional standards, accounting, statistics and analysis, economics, fixed income securities, equity securities, and portfolio management.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to address whether the Commission should approve the "Unwind Transaction", related planned issuances of evidences of indebtedness, and other requests of the Joint Applicants, based on the financial projections of Big Rivers Electric Corporation ("BREC"). My review was conducted under the applicable legal standard as provided to me by counsel. In accomplishing my review, I consider information contained in the Application and supporting filed materials, and materials provided through discovery in this case. In particular, I have reviewed and considered

1. The nature and extent of the BREC organization, both current and proposed;
2. Statements and rationale offered by Joint Applicants as to why the proposed transactions are in the public interest;
3. E.ON, BREC/cooperatives, and Smelters' internal managerial analyses, presentations and reports;
4. The completeness of the Application and supporting materials;
5. The financial projections and related materials offered by BREC in support of the proposed transactions; and,
6. The proposed agreements among BREC, Kenergy and the aluminum smelters, including termination provision.

Q. WHAT STANDARD DID YOU USE FOR YOUR REVIEW?

A. I am advised by counsel that the standard for use in this case is from KRS 278.300(3),[1] which states:

> The commission shall not approve any issue or assumption unless, after investigation of the purposes and uses of the proposed issue and the proceeds thereof, or of the proposed assumption of obligation or liability, the commission finds that the issue or assumption is for some lawful object within the corporate purposes of the utility, is necessary or appropriate for or consistent with the proper performance by the utility of its service to the public and will not impair its ability to perform that service, and is reasonably necessary and appropriate for such purpose.

[1] The Attorney General notes that the Informal Conference Memorandum dated January 16, 2008, referenced the December 18, 2007, order in Case No. 2007-00374 as governing the transfer in the instant matter. That order clearly states that KRS 178 300 applies.

This standard appears to require more than a generalized public interest finding regarding the proposed transactions. Other implications of the standard include:

- It clearly suggests that the "proposed issue" (or assumed obligation or liability) is in fact known to the Commission;
- The Commission must find the proposed issue to be necessary for the proper performance by the utility of its service to the public;
- The Commission must find that the proposed issue will not impair the utility's ability to perform its service to the public; and,
- The Commission must find that the proposed issue is reasonably necessary for the utility to perform its service to the public.

Q. DOES YOUR TESTIMONY ADDRESS THE LEGALITY OF THE VARIOUS SURCHARGES, SURCREDITS, OR OTHER RATE MAKING PRINCIPLES WHICH ARE INCLUDED IN THIS FILING?

A. No. The scope of my work for the Attorney General does not include any analysis of the legality of any of the surcharges, surcredits or rate making principles.

Q. DOES YOUR TESTIMONY REFLECT THE FULL POSITION OF THE ATTORNEY GENERAL'S OFFICE ON THIS TRANSACTION?

A. No. I have been advised that the Attorney General is considering many factors in this "unwind," including the economic impact with the loss of jobs associated with the possible closing of the smelters. However, I have not been apprised of any of the details. My engagement is limited to whether BREC will be financially viable on a going forward basis following any approval of the transaction. This includes a scenario if both smelters leave the system.

Q. WHAT INFORMATION DID YOU REVIEW IN ORDER TO PREPARE THIS TESTIMONY?

A. I reviewed and considered the information contained in the multiple exhibits and testimonies associated with the Application, information provided in response to data requests, as well as information from newspapers such as the <u>The Wall Street Journal</u>.

Q. AT THE OUTSET, DO YOU BELIEVE THAT A COMPLETE APPLICATION INCLUDING NECESSARY SUPPORTING DOCUMENTS HAS BEEN PUT BEFORE THE COMMISSION AND THE PARTIES?

A. No, in my view the Application and supporting documents are substantively incomplete in at least four crucial areas:

- There are no specific debt issue or specific creditor agreements for the Commission to review and consider. Big Rivers has had to "explore financing alternatives" due to "the unsettled condition in the credit market and the extremely wide credit spreads".[2] The "proposed new financing agreement"[3] suggested by Joint Applicants cannot be provided, and instead an alternative interim approach is being utilized.[4] "Big Rivers financing plans have changed as a result of the upheaval in the public financial markets that has occurred over the past months."[5] Most of the documents associated with the latter interim approach have not been provided and apparently are not complete or available at this time;
- Credit ratings have not yet been obtained by BREC, although an investment grade credit rating is a required condition for the proposed transactions;
- Required consents to the proposed transaction have not been obtained by the parties, including existing creditors and approvals/releases from the City of Henderson, and the amounts of the consent fees that will be required to be paid are not known or estimable by the parties; and,
- BREC has not completed and provided a due diligence report on the generating facilities.

This testimony must be considered as preliminary until the record has been supplemented by the Joint Applicants to include and address these crucial areas, which are demonstrably and materially incomplete. In addition, some time will also be necessary for the parties and the Commission to address this new information.

<u>Proposed Transaction, Transaction History and Objectives of the Parties</u>

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2 BREC response to OAG Supplemental No 116

3 Exhibit 10, Direct Testimony of C. William Blackburn, page 11, line 3.

4 BREC First Amendment and Supplement to Application, paragraph 19. BREC does provide two documents associated with $100 million in lines of credit/revolving credit arrangement, but the larger public debt offering remains indefinite and in the future.

5 Id.

Q. PLEASE DEFINE "UNWIND TRANSACTION".

A. My intent is to ascribe the same meaning to that term as intended by the parties. "Unwind Transaction" is defined by Joint Applicants to be "the combined transactions by which Big Rivers and the E.ON entities propose to terminate and unwind the 1998 Transactions".[6] The 1998 transactions were part of Big Rivers' implementation of its bankruptcy reorganization, and included leasing Big Rivers' generating facilities to E.ON's predecessor for it to manage, operate and maintain; transferring responsibility to manage, operate and maintain two additional generating units owned by the City of Henderson (through Henderson Municipal Power & Light, or "HMPL"); purchasing by Big Rivers of a set amount of power at substantially fixed prices through a Power Purchase Agreement that it uses to serve the loads of its three member cooperatives; payment by LG&E Energy Marketing ("LEM") to the US Rural Utilities Service ("RUS") of monthly margin payments; and, providing a portion of the Smelters' power needs at substantially fixed rates through power supply contracts between LEM and predecessors of Kenergy. The facilities lease and power purchase agreements terminate in 2023 by the terms of those agreements, and the power supply contracts for the smelters terminate in 2010-2011.

Q. IN ADDITION TO SEEKING APPROVAL OF THE UNWIND TRANSACTION, ARE THE JOINT APPLICANTS SEEKING APPROVAL OF ANY OTHER MATTERS?

A. Yes. The Joint Applicants also seek a number of approvals which are listed in Exhibit 29, and include:

1. A set of new agreements with the smelters by which Big Rivers and Kenergy propose to serve essentially all of the needs of the smelters for electric power through 2023;
2. A new set of rate mechanisms to address retail rates between the closing of the unwind transaction and the date at which the Commission approves new rates pursuant to a general rate proceeding to be filed no later than three years after the date of a final order in this proceeding;

[6] Application, paragraph 10

3. Issuance of certain evidences of indebtedness (which have not yet been created or provided in this matter);
4. Amending Big Rivers' Member cooperative Wholesale power contracts; and,
5. Terminating and rescheduling Big Rivers' pending IRP proceeding.

Q. THE 1998 FACILITIES LEASE AND POWER PURCHASE AGREEMENTS BETWEEN BIG RIVERS AND E.ON HAVE A 25 YEAR TERM, EXPIRING IN 2023. WHICH PARTY INITIALLY BROACHED THE POSITION OF TERMININATING THE AGREEMENTS?

A. It is stated E.ON approached Big Rivers in 2003, seeking to unwind the transactions.[7] Discussions occurred over a number of years, resulting in execution of a letter of intent to negotiate a transaction termination ("unwind") agreement in December 2005, execution of the termination agreement by the Joint Applications in March 2007, substantial agreement to the Smelter Agreements in December 2007, and the Application in this matter was filed before the Commission on December 28, 2007.

Q. WHAT ARE E.ON'S INTERESTS DRIVING ITS PURSUIT OF THE UNWIND TRANSACTION?

A. Limited general information is available directly from E.ON's on its interest in terminating the transactions, through the initial and supplemental rounds of discovery. Since the original agreements were reached between LG&E and Big Rivers, there had been a succession of ownership changes of LG&E, first being acquired by Powergen, which was subsequently acquired by E.ON. The Application is somewhat cryptic on the point of E.ON's interests, where it notes that the Commission approved the 1998 transactions as being reasonable and proper, "but circumstances have changed".[8] The Application states "the business plan of E.ON U.S. [is] to focus on its regulated lines of business rather than on wholesale generation."[9] It is apparent that in recent years, E.ON has lost money on its energy marketing operation—LEM—and that the "transactions with Big Rivers ... had not

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7 Exhibit 14, Direct Testimony of Michael H. Core, page 4, line 19.

8 Application, paragraph 10, line 17.

9 Application, paragraph 11.

proven advantageous to E.ON U.S."[10] "The rates charged by E.ON are currently not directly affected by changes in fuel and environmental costs, and, in fact, there have not been any adjustments to the purchased power rates charged by E.ON due to changes in fuel or environmental costs since the lease and purchased power arrangement was established in 1998."[11]

EON overall corporate strategy goals are not clear. There are differences between company strategy statements in its financial reports versus equity analyst reports. Some equity analyst reports suggest that E.ON's US operations could be sold. E.ON could be disposing of the BREC obligations to prepare for disposition of the remaining US operations. E.ON's 2006 Annual Report (page 69) shows no "new markets" in the US, all E.ON's "new markets" are in Europe. Further, E.ON US is a declining proportion of total EON revenues.[12]

Q. WAS E.ON DIRECTLY ASKED FOR INFORMATION, ANALYSES AND DOCUMENTS REGARDING ITS INTERESTS IN PURSUING THE UNWIND TRANSACTION?

A. Yes, this information was sought via interrogatories issued by the Office of Attorney General. However E.ON objected to providing that information, and it was not provided in discovery. In contrast, Big Rivers, the member cooperatives, and the Smelters have generally provided this information,[13] so those perspectives on the transaction are relatively clear to the parties and the Commission. At a later date, E.ON did however provide some relevant information regarding the economics of the Lease Agreement (but not overall corporate goals) to the parties under confidential claim.

Q. WHAT ARE THE OBJECTIVES OF THE SMELTERS IN THIS MATTER?

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[10] Application, paragraph 21.

[11] Exhibit 25, Direct Testimony of William Steven Seelye, pages 4-5, lines 20-2

[12] E.ON response to OAG No. 97, 2006 Form 20-K, page 36.

[13] See for example, Member Cooperatives Response to OAG Supplemental 1.

A. Century Aluminum Company operates the Hawesville smelter, which is adjacent to Southwire's Rod and Cable Mill.[14] Rio Tinto Alcan operates the Sebree smelter.[15] The Smelters state "aluminum is a global commodity … [that] is sold at a price that is based on global supply in demand and established by trading activity on the London Metal Exchange, or LME."[16] In other words, aluminum producers are "price takers" of the market price for aluminum. The Smelters further state that "in general, the cost of alumina, labor and electricity accounts for 75-80% of the cost [of production of aluminum], with alumina and electricity each comprising about one-third of the cost of production. … it is the cost of electricity that most significantly determines the ongoing success or viability of an aluminum smelter."[17] In addition to price, the reliability of the energy supply is critical. "The Smelters require 100% reliable energy supply."[18] The immediate present situation of the Smelters is that their respective power supply contracts through E.ON expire in 2010-2011, and E.ON has indicated the contracts will not be renewed upon expiration. Furthermore, those contracts only provide for a portion of the Smelters' electricity needs, with the remaining needs being met via purchases on the open market at higher prices. In sum, "the Smelters require an affordable and predictable energy supply in order to make the large capital investments necessary to maintain and operate their production facilities efficiently. … The proposed agreements provide a power supply that can reasonably be expected to be significantly lower-cost and less volatile than market-priced power."[19] Alcan states "we believe that cost based rates from coal fired generation that are close to the fuel supply and to the smelter, which have relatively low capital costs and which comply with existing environmental regulations, provide a better option for us than market priced electricity."[20]

Q. WHAT CONCERNS DO THE SMELTERS EXPRESS?

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[14] Direct Testimony of Wayne Hale on behalf of Century Aluminum Company, page 2, lines 1-4

[15] Direct Testimony of Guy Authier on behalf of Rio Tinto Alcan, page 2, line 1.

[16] Direct Testimony of Henry W. Fayne, page 3, lines 20-22.

[17] Direct Testimony of Henry W. Fayne, page 4, lines 8-13.

[18] Direct Testimony of Henry W. Fayne, page 10, line 17.

[19] Direct Testimony of Henry W. Fayne, page 14, lines 12-19.

[20] Direct Testimony of Guy Authier on behalf of Alcan, page 2, line 14.

A. While the Smelters support the transaction as "the best alternative available", and "have concluded that it is reasonable to expect that costs will be within the range projected in the financial model, if not lower,"[21] the support is tempered by the following concerns:

1. If industry analysts are correct about the long term price of aluminum, "then long-term operation of the Smelters at the rates projected in the financial model will be a close call. Certainly, if costs increase significantly, the Smelters will be unable to survive."[22]
2. "The financial model was prepared solely by Big Rivers. ... the Smelters do not have sufficient information to agree or disagree with the forecast."[23]
3. "There is still an outstanding issue with the City of Henderson. If the resolution of that issue imposes additional cost to the Smelters, the transaction may no longer be viable."[24]
4. "The new financing arrangements have not been completed. If the cost of refinancing is higher than reflected in the financial model, the transaction may no longer be viable."[25]

Q. DID THE SMELTERS PROVIDE INTERNAL CONFIDENTIAL ANALYSES PERTAINING TO THE PROPOSED TRANSACTIONS?

A. Yes, my understanding is that these confidential responses were provided only to the Office of the Attorney General in response to its data requests.

Q. PLEASE OUTLINE CONCLUSIONS FROM ALCAN'S ANALYSES, PROVIDED IN RESPONSE TO OAG No. 1-8, AND PROVIDED ONLY TO THE OFFICE OF THE ATTORNEY GENERAL.

A. My current understanding of the confidential classification of this response is that only Alcan, Century and the Commission may see the confidential information, in addition to the Office of the Attorney General. The Alcan analysis states as follows **[BEGIN**

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[21] Direct Testimony of Henry W. Fayne, page 15, line 19.

[22] Direct Testimony of Henry W. Fayne, page 14, lines 5-8.

[23] Direct Testimony of Henry W. Fayne, page 15, lines 5-10.

[24] Direct Testimony of Henry W. Fayne, page 16, line 2.

[25] Direct Testimony of Henry W. Fayne, page 16, line 5.

SMELTER CONFIDENTIAL] [redacted]

[END SMELTER CONFIDENTIAL] The Century analysis states as follows **[BEGIN SMELTER CONFIDENTIAL]** [redacted]

[redacted]

[redacted]

[END SMELTER CONFIDENTIAL]

Q. DO THE SMELTERS HAVE AN INCENTIVE AND ABILITY TO AFFECT BREC'S OPERATIONS UNDER THE PROPOSED TRANSACTION?

A. Yes, the Smelters have a strong incentive to take any available actions to minimize or otherwise reduce rates charged to the Smelters. The Smelters have the ability to take direct action on this incentive in a variety of ways, including advocacy positions before policymakers including the Commission, and through Sections 3.4 and 4.1 of the Coordination Agreement with BREC. Section 4.1 provides for the establishment of a Coordinating Committee. The Committee consists of "representatives of the Members, the Smelters, and Big Rivers' management, organized for the purpose of reviewing, analyzing and discussing information relating to Big Rivers' operational and financial performance."[26] The Committee shall meet at least once every calendar quarter, and is able to examine the following information:

- "analysis criteria and procedures for evaluating plans, procedures, expenditures, and maintenance programs;
- Budgets;
- Operations and capital expenditures;
- Fuel procurement or supply;

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[26] Exhibit 5, Direct Testimony of Mark Bailey, page 25, lines 2-5.

- Comparison of actual performance to the budget and explanation of variances between actual performance and the budget;
- Load forecasts and integrated resource plans;
- Depreciation studies, proposed changes in depreciation rates and associated proposed changes in electric rates; and,
- Other activities that may impact Big Rivers' operational and financial performance."[27]

Section 3.4 provides:

- Each year, BREC will provide the Smelters a copy of its then current proposed annual capital and operating budget for the following fiscal year, along with reasonably requested supporting information;
- The Smelters may request review of the budget by an independent expert mutually agreed to with BREC;
- The Smelters may present a report from the independent expert to the BREC board;
- BREC is obligated to provide notice to the Smelters of certain upward departures from budgeted amounts; and,
- The Smelters can request the Coordinating Committee discuss the causes of budget variances and present to the BREC Board of Directors on the subject.

Clearly, the Smelters are entwined with BREC management and have the ability for substantial influence on BREC operating and financial matters in support of Smelter interests in lower power rates.

Q. WHAT ARE THE INTERESTS OF BREC AND THE MEMBER COOPS IN PURSUING THIS UNWIND TRANSACTION?

A. In their response to OAG No. 1, the member cooperatives state they support the Unwind transaction because:

1. "It will result in a more financially secure Big Rivers with positive equity and an investment grade credit rating. As owners of BREC it is in the Members' interest for BREC to have financial stability;

[27] Id., lines 7-15.

2. BREC will be better able to provide power for economic development should the need arise; and
3. The Unwind will help keep jobs in the local community by providing the smelters a source of electricity that can maintain their profitability."

BREC amplifies these points in response to OAG No. 1, No. 43, and others. BREC states that it "will receive large and immediate and tangible benefits under the unwind transaction—to the tune of approximately $623 million from E.ON alone and approximately $327 million in contributions from the Smelters."[28]

Q. DID THE COOPERATIVES PROVIDE INFORMATION AND ANALYSIS REGARDING THEIR VIEWS OF THE PROS AND CONS OF THE UNWIND TRANSACTION?

A. Yes. In response to OAG Supplemental No. 1, the cooperatives provided substantial documentation regarding the evaluation and consideration of the proposed transaction. The member cooperatives "exercise control of Big Rivers through representation on the Big Rivers board of directors", and determined that "Big Rivers should prepare studies, hire consultants and otherwise produce the necessary documentation for their review and consideration of the proposed transaction." The cooperatives provided "documents from the calendar year 2007 that relate to analysis of the Unwind Transaction and the existing transaction, under which Big Rivers currently operates." These documents are claimed confidential and include explanations to the Board of the proposed new smelter agreements and the Unwind transaction, and presentation/review of the Termination Agreement, the smelter agreements, Unwind schedule, Pros/Cons/Recommendation, and iterative updates of proposed transaction financial data.

Q. PLEASE PROVIDE THE INFORMATION FROM THESE DOCUMENTS THAT YOU FIND MOST RELEVANT TO THE COMMISSION'S CONSIDERATION OF THIS MATTER.

A. The first document I will provide excerpts (direct quotes) from is **[BEGIN BREC/MEMBER COOPERATIVE CONFIDENTIAL]** [redacted]

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[28] BREC response to OAG No 43

[redacted]

[redacted]

[redacted]

[END BREC/MEMBER COOPERATIVE CONFIDENTIAL]

Q. WHAT IS THE RATIONALE IN SUPPORT OF THE UNWIND RECOMMENDATION FROM THAT FIRST DOCUMENT?

A. It states BREC should Unwind for the following reasons:

[redacted] **[BEGIN BREC/MEMBER COOPERATIVE CONFIDENTIAL]** [redacted]

[redacted]

[redacted] **[END BREC/MEMBER COOPERATIVE CONFIDENTIAL]**

Q. PLEASE CONTINUE TO THE SECOND DOCUMENT.

A. The second document is a presentation from the same day **[BEGIN BREC/MEMBER COOPERATIVE CONFIDENTIAL]** [redacted]

[redacted] [END BREC/MEMBER COOPERATIVE CONFIDENTIAL]

Financial Model Projections

Q. HAVE YOU REVIEWED THE FINANCIAL MODEL PREPARED BY BREC AND SUBMITTED IN THIS CASE AS EXHIBIT 8?

A. Yes. BREC states that "the 'Unwind Financial Model' … is the principal financial evidence Big Rivers submits in support of its Application and the various approvals sought herein."[29] I have reviewed that model but have focused on the subsequent iterations of it including the errata run and sensitivity runs provided in response to interrogatories, particularly those provided in response to PSC No. 10 and No. 12. BREC suggests that the model run it has provided in the application is a "Base Case" view, which in my view means it is not intended to be either overly optimistic or pessimistic. I take BREC's

[29] Application, paragraph 26

financial modeling to be a "central" prediction or projection of future financial results. Furthermore, BREC intends the projections to reflect "least cost" financing decisions—BREC states its "least cost" direction means "the structuring of potential financing such that the most expensive debt components are repaid early, and the less expensive components are kept in place as long as possible, within the constraints of maturities imposed by contract or tax regulations and other objectives such as reducing RUS exposure".[30] However, this "least cost" direction has no doubt been affected by current credit market conditions which have prevented Big Rivers' execution of its original financing plan as incorporated in the model, and required reversion to an alternative financing plan. This alternative plan implies restructuring existing RUS debt to fit the debt service level contemplated in the Model—which is necessarily a deferral of debt service given that a smaller prepayment will be made, and interest expense will be higher. This deferred debt service will either be paid on that deferred schedule, or prepaid via proceeds from later financing. It is unknown at this time what later circumstances will permit. The later sale of public debt is anticipated to raise an additional $200 million to make a further prepayment of RUS debt. Of course, the timing, cost and proceeds from this future debt offering cannot be known at this time. Presumably BREC will seek to accomplish these financing steps in "least cost" fashion, but whether it is as "least cost" as that presumed in the model remains to be seen—the process could be more expensive in total than that projected in the model. The impact of these considerations will apparently be addressed in an upcoming filing by BREC of a revised financial model which addresses the alternative financing structure.

Q. IS BREC'S FINANCIAL MODEL RUN INHERENTLY OR INNATELY CORRECT?

A. No. As with any financial projections, actual results can and will differ. Future deviations from inputs and assumptions (e.g., the Production Work Plan; departure of one or both Smelters; capital expenditures; environmental requirements; fuel costs; financing costs) represent risks that the financial projections will not be achieved. There are a myriad of assumptions in the projections which may or may not hold true. The span and range of

[30] BREC Response to OAG No. 1-48

these risks is also illustrated in Appendix A of BREC's Enterprise Risk Management Policy.[31]

Q. DOES THE FINANCIAL MODEL INCLUDE ALL COSTS TO RECTIFY MAINTENANCE AND OTHER CONCERNS REGARDING BREC'S GENERATING FACILITIES?

A. It appears that such costs would not necessarily be included since BREC has not completed its due diligence review. The Production Work Plan which BREC has incorporated into the financial model "is based upon the existing WKEC work plan for 2008-2010. ... Big Rivers has made <u>relatively minor changes</u> to incorporate into the plan certain capital projects that it plans to undertake during 2009 and 2010."[32] Furthermore, as elaborated upon below, the Stone & Webster Technical Assessment for the Smelters **[BEGIN SMELTER CONFIDENTIAL]** [redacted] **[END SMELTER CONFIDENTIAL]**

Q. DOES E.ON PROVIDE ANY REPRESENTATION OR WARRANTY TO BREC REGARDING THE CONDITION OF THE GENERATING PLANTS AND SITES?

A. **[BEGIN BREC/MEMBER COOPERATIVE CONFIDENTIAL]** [redacted] **[END BREC/MEMBER COOPERATIVE CONFIDENTIAL]**

Q. HAVE YOU OBSERVED EVIDENCE OF CONCERNS REGARDING RECENT YEARS' MAINTENANCE AND THE CONDITION OF THE FACILITIES?

A. Yes. A number of documents in this case reference concerns regarding recent years' maintenance and the condition of the facilities. These documents include:

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[31] Exhibit 5, Direct Testimony of Mark Bailey, Exhibit MAB-5, pages 8-11.

[32] Exhibit 5, Direct Testimony of Mark Bailey, page 5, lines 11-16, <u>emphasis added</u>.

[33] Cooperative response to OAG Supplemental No 1, "Executive Summary Relating to the Unwind of E ON US Arrangements", page 6

1. BREC's response to OAG No. 1-27, which suggests that the facilities may be operated differently on a regulated basis by BREC than on an unregulated basis by E.ON. "The regulated production assets under Big Rivers' control may be operated differently than if they were unregulated assets. Some of the differences could be fuel mix, operating and maintenance objectives, generation levels, and economic dispatch criteria." (Emphasis added.)
2. Smelters response to OAG No. 1-3, which attaches a Stone & Webster Technical Assessment **[BEGIN SMELTER CONFIDENTIAL]** [redacted]
   - [redacted]
   - [redacted]

   [END SMELTER CONFIDENTIAL]
3. BREC's response to OAG Supplemental No. 103 provides **[BEGIN BREC/MEMBER COOPERATIVE CONFIDENTIAL]** [redacted]

[34] BREC response to Supplemental OAG No. 1-103, Confidential Information Memorandum, December 19, 2005, page 5.

[redacted] **[END BREC/MEMBER COOPERATIVE CONFIDENTIAL]**

4. The Member Cooperatives response to OAG Supplemental No. 1 contains repeated references to maintenance concerns. For example, **[BEGIN BREC/MEMBER COOPERATIVE CONFIDENTIAL]** [redacted]

[redacted]

[redacted]

[redacted]

- [redacted] **[END BREC/MEMBER COOPERATIVE CONFIDENTIAL]**

Q. HAVE THE SMELTERS PERFORMED A DUE DILIGENCE REVIEW OF THE GENERATING FACILITIES?

A. Yes, the Smelters seem to be the only party which has performed and completed a due diligence review. The Smelters response to OAG No. 3 contains a confidential attachment which provides a Stone & Webster Technical Assessment dated May 18, 2007. This response was subsequently supplemented and updated to provide a later final report dated March 11, 2008 containing a Technical Assessment of the generating facilities, which is also considered confidential. This report to the Smelters **[BEGIN SMELTER CONFIDENTIAL]** [redacted]

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[35] Id., page 38.

[36] Member Cooperatives response to OAG Supplemental No. 1, September 20, 2007, Board presentation, page 26.

[37] Id., September 20, 2007 Annual Meeting presentation, pages 21, 22, 25

[38] Smelters Supplemental response to OAG No 3, page 1

[redacted] **[END SMELTER CONFIDENTIAL]**

Q. DOES THE FINANCIAL MODEL INCLUDE FINANCIAL CONSIDERATION AS EXCHANGED IN ASSOCIATION WITH THE PROPOSED TRANSACTIONS?

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[39] Id.

[40] Id., page 4.

[41] Id., page 4, emphasis added

A. Yes, the model reflects the financial considerations as stated in BREC's testimony.[42] BREC receives $301.5 million in cash proceeds. BREC receives fuel and other inventory valued at $55 million, SO_2 allowances valued by BREC at $10.9 million, forgiveness of the residual value payment obligation associated with the lease transaction in the amount of $150.4 million, the scrubber installed at the Coleman plant valued at $97.5 million, and forgiveness of a note to E.ON in the amount of $16 million. The transaction will also cause or accelerate recognition of certain items ($11.4 million in deferred E.ON lease revenue; $15.7 in expenses currently being amortized; and, assumption of an E.ON liability of $4.3 million to the smelters). This totals to the $622.7 million consideration to be recognized by BREC under the proposed transaction. In addition one payment is not reflected in the model, "WKEC has agreed to pay to the smelter customers, collectively, at the closing a sum of money in immediately available funds".[43] This sum of money is **[BEGIN E.ON CONFIDENTIAL]** [redacted] **[END E.ON CONFIDENTIAL]**.[44]

Q. DOES BREC INTEND TO REDUCE ITS DEBT UNDER THIS TRANSACTION?

A. Yes. The model reflects BREC's original plans to apply part of its cash proceeds to debt reduction, prepayment of a portion of RUS debt and incurrence of new public markets debt, and also to the establishment of two restricted cash accounts. The model shows that $195.8 is applied to debt restructuring, $75 million is restricted to the Economic Reserve fund, and $35 million for the Transition Reserve fund. In the model, the originally planned debt restructuring is the net of prepayment of RUS debt (cash out of $449.7 million), new capital markets debt (cash in of $263.5 million), and costs of underwriting ($4.6 million) and bond insurance ($5.0 million). Under the alternative financing plan, BREC has provided information on a revolving line of credit with National Rural Utilities Cooperative Finance Corporation (CFC), and a Revolving Credit Agreement with CoBank, the principal balances for each of which is not to exceed $50 million. In addition under this alternative plan, BREC intends to

> use proceeds from the Unwind Transaction to prepay approximately $200 million of its RUS debt, and restructure the debt service schedule on the remaining balance of

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[42] E.g., Exhibit 10, Direct Testimony of William Blackburn, pages 12 – 19.

[43] Exhibit 15, Testimony of Paul W. Thompson on behalf of E.ON, page 13

[44] E.ON Confidential Response to OAG No. 1-83

> the RUS debt to approximate the debt service contemplated in the Unwind Financial Model. Big Rivers expects the RUS Amended and Restated Loan Contract, discussed below, to require that Big Rivers sell sufficient public debt within a fixed period of years to pay an approximate additional $200 million on Big Rivers' RUS debt.[45]

However, these plans have not been reflected in an updated run of the Financial Model as provided to the Commission and the parties.

Q. IF THE ALTERNATIVE FINANCING PLAN RESULTS IN INCREASED COSTS AND REQUIRED CASH FLOW AT ANY POINT IN TIME, SHOULD THE COMMISSION EXPECT PRESSURE ON BREC FROM THE SMELTERS TO DEFER SUCH INCREASED COSTS AND REQUIRED CASH FLOW?

A. Yes. The Smelters have stated "If the cost of refinancing is higher than reflected in the financial model, the transaction may no longer be viable."[46] The Smelters also state "As shown in the financial model prepared by Big Rivers and submitted in this proceeding, interest expense other than interest expense related to the sale-leaseback transaction is expected to average about $45.4 million/year during the first three years of the contract, and decline thereafter. The interest expense reflected in the model is the target level of performance."[47] The Smelters have both the incentive and ability through participation on the Coordinating Committee to pressure BREC to avoid arrangements which might increase costs in the shorter term, and defer such costs to a later date. Such cost deferral may or may not be coincident with the public interest, or interests of the general body of ratepayers.

Q. ARE THE SMELTERS' INTERESTS NECESSARILY THE SAME AS THE INTERESTS OF BREC AND ITS MEMBERS?

A. No, the Smelters' interests are not necessarily the same as BREC and the member cooperatives. The Smelters are for-profit entities whose revenues are constrained by market prices and conditions. The Smelters' preponderant interest in this case is the lowest achievable cost for power, so long as the Smelters are operating in Western Kentucky.

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[45] BREC First Amendment and Supplement to Application, paragraph 19.

[46] Direct Testimony of Henry W. Fayne, page 16, line 5.

[47] Smelters' Response to OAG No. 1-19.

Whenever the Smelters cease operations, their interest in the cost and price of power in Western Kentucky no longer exists. The Smelters would tend to favor deferral of cost recognition in near term periods, leaving costs for later recovery at a point in time when the Smelters' may no longer be operating in Western Kentucky. This is clearly the case in this matter on the subject of depreciation. From a December 21' 2007 email (one week before the Application was filed at the Commission):

> I just received word that the Smelters are on board with the latest model update. Sandy, Steve and Nib may not be aware that BREC agreed to go back to the depreciation rates methodology reflected in the September model for the years 2011 – 2016. They are also using the current rates for 2008 – 2010 which result in slightly less depreciation expense in those years. The net effect is lower rates for all but less recovery [of] the plant value from the Smelters within the finite period of the deal.[48]

This obviously leaves plant capital recovery to a later time when market conditions affecting coal power plants could be much more uncertain and challenging. If the Smelters are not there to share in the capital recovery load at that time, the full burden will fall to remaining ratepayers. Furthermore, it can be expected that there will be an advocacy position from the Smelters, if they are still present, against assigning such capital recovery responsibility to the Smelters with the same basis as before the Commission currently—loss of jobs in an industry facing worldwide competition.

Also, the Smelters **[BEGIN SMELTER CONFIDENTIAL]** [redacted]

[48] BREC Response to OAG No. 1-119, email from Jack D. Gaines dated December 21, 2007, emphasis added.

[redacted] **[END SMELTER CONFIDENTIAL]**

Q. DOES BREC STATE IT STANDS TO EARN MORE REVENUES IF THE SMELTERS DEPART?

A. Yes. BREC's response to Commission staff No. 10 indicates that "revenues lost as a result of both Smelters' departure, with a ten percent reduction in market prices, are more than recovered by alternative sales into the market." BREC provides financial model scenarios in support of this. What is not stated here is that part of the increased revenue comes from higher rates being charged to consumers. Exhibit DB-2 compares the Rural "effective rate" (page 3, line 46 of the Financial model) for the "base case" versus "both Smelters depart" cases, and shows rates increased up to 18%.

Impact of Support Provisions

Q. TO WHAT ARE YOU REFERRING WITH THE TERM "SUPPORT PROVISIONS"?

A. By this term, I am referring to the various means and mechanisms BREC uses to defer or mitigate rate impacts on consumers. This would include such items as the Member Rate Stabilization Account (MSRM), the Transition Reserve, the Tier Adjustment charge paid by the Smelters, and the surcredit mechanism.

Q. ARE THE ASSERTED BENEFITS OF THE PROPOSED TRANSACTION FROM THE SUPPORT PROVISIONS AND OTHER COMMITMENTS EVENLY

[49] Smelter response to OAG No. 1-8

[50] Smelters Supplemental response to OAG No 1-3, page 4

DISTRIBUTED OVER THE PERIOD OF THE PROJECTIONS IN THE FINANCIAL MODEL?

A. No. The support provisions associated with the proposed transaction and other benefits in several cases occur or are consumed in the early years of BREC's financial projections. While the early benefits are enticing in nature, once the benefits are used up, BREC's operations are become exposed to market and economic events and risks. Examples include:

1. BREC's plan not to increase member rates initially, but rate increases are assumed in the model at 2011 (2%), 2015 (1.02%), and 2017 (9.98%);
2. BREC's depreciation rates in the financial model may have been artificially depressed to meet Smelter requirements, with overhanging later depreciation rate study and depreciation rate increase which would tend to affect all consumers;
3. Temporary funds are set up to shield BREC consumers from rate increases in environmental surcharge and fuel adjustment clause costs for a limited period (approximately five years);
4. Large up-front payments in cash and other consideration from E.ON (approximately $622 million);

Q. WHAT ARE THE IMPACT AND IMPLICATIONS OF THE TIER ADJUSTMENT CHARGE MECHANISM FROM THE SMELTERS?

A. In the first two years under the financial projections, the Smelters receive a rebate from the TIER adjustment mechanism. In later years, the Smelters pay additional costs under the TIER adjustment mechanism. But the actual adjustment will be a complex calculation, and could potentially deviate from what is projected. The TIER Adjustment Charge as paid for the benefit of non-Smelter member rates is subject to potential reduction for an extensive list of items in the Smelter Agreements (Section 4.7.5), including:

1. Imputed rate increases to non-Smelter member rates in 2010, 2018, and 2021, for which increased charges under FAC and Environmental Surcharge Rider do not count;
2. Imputed revenues from "New Ratepayers" at the Large Industrial Rate;
3. Imputed interest expense reductions, including those associated with construction of non-peaking generating facilities under certain circumstances;

Furthermore, the TIER adjustment payments from the Smelters are subject to a hard cap. The Smelters' obligations may not exceed the total of the Large Industrial rate for a customer with a 98% load factor plus $0.25 per MWh plus the applicable amount from the table in section 4.7.1 of the Smelter agreements:

Fiscal Years	**Maximum Additional Charge**
2008-2011	$1.95 per MWh
2012-2014	$2.95 per MWh
2015-2017	$3.55 per MWh
2018-2020	$4.15 per MWh
2021-2023	$4.75 per MWh

Times Interest Earned Ratio (TIER) Considerations

Q. WHY IS THE TIER IMPORTANT FOR THIS PROCEEDING?

A. The "times interest earned ratio" (TIER) is an income statement-based calculation which compares a company's earnings level to its annual interest expense. It is one ratio used to measure a company's ability to meet its debt obligations. The higher the ratio, the greater is the company's indicated ability to cover its interest payments. As such, the ratio also helps assess the financial risk associated with the company's operations. Implications from TIER are present in many aspects of the case. First of all, TIER is a notable input into the credit rating process.[51] As such, it will be one aspect of the credit rating entities assessment of BREC's creditworthiness and credit ratings (further discussed below). The TIER calculation is also a crucial element of contracts with the Smelters, in that the Smelters subject to certain limitations will pay to support BREC's annual achievement of a minimum TIER level (1.24x, as specified in the Glotfelty testimony). Correspondingly, the financial model is built to accommodate TIER considerations with the Smelters and to yield periodic TIER calculations and TIER support payments from the Smelters. Ultimately, TIER requirements will affect ratepayers who will be required to pay rates that cover operating costs, depreciation and margins including interest/debt service coverage.

Q. ARE THERE DIFFERENT TIER CALCULATIONS?

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[51] See BREC response to OAG No. 1-60, generally; and, Exhibit 21, Direct Testimony of Mark W. Glotfelty, page 4.

A. Yes. As explained by BREC, there may be at least three different TIER calculations. In its financial modeling and contracting with the Smelters, BREC uses a "conventional TIER". This TIER measures coverage of interest and financing charges on all debt (including sale-leaseback debt, but net of capitalized interest) on a pre-tax basis.[52] A second measure is for Rural Utilities Service (RUS) purposes, which measures coverage of interest on long term debt only and on an after-tax basis.[53] A third measure is one employed by the Commission for ratemaking purposes, which divides the sum of net margins and interest on long term debt by interest on long term debt. BREC states:

> It is not Big Rivers' intention to suggest that the Commission adopt Conventional TIER for rate-making purposes. The Conventional TIER is offered solely for reference purposes as to the criteria that may be applied to Big Rivers' creditors, rating agencies, and others in assessing the Unwind Transaction. It is intended to show the outcome in conventional terms of stipulating a revenue requirement from the members and the Smelters sufficient to achieve a "contract TIER" equal to 1.24x.[54]

BREC response to OAG No. 46 states that "the creditors and credit rating agencies will likely use the conventional TIER calculation."

Q. DOES THE OBJECTIVE TIER LEVEL STATED BY THE COMPANY APPEAR REASONABLE?

A. The 1.24x TIER level as supported by Mr. Glotfelty appears reasonable for the intended purpose ~~of the financial projections and~~ related agreements including ~~the~~ Smelter agreements. Of course, in later rate proceedings, the Attorney General (and staff and the Commission) may choose to differ from this TIER level based on facts, analysis and circumstances present at that time.

Q. IF BIG RIVERS' NEW CREDIT AGREEMENTS ARE INCOMPLETE AND NOT PRESENTED AT THIS TIME, IS THE INTEREST EXPENSE DETERMINABLE FOR PURPOSES OF THE COMMISSION'S DECISION?

A. No. Interest expense is the crucial variable for calculation of TIER, along with the financial modeling of profits. Big Rivers has stated its estimated required TIER, but the actual projected TIER remains unknown to the Commission and other parties until credit

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[52] BREC response to Staff No. 1-13.a

[53] Id.

terms including interest rates are finalized with creditors. One clear implication of the uncertainty of TIER is that this renders the Smelters' participation in the transaction uncertain. The Smelters have stated that "if the cost of financing is higher than reflected in the financial model, the transaction may no longer be viable."[55] The Smelters further state that "the interest expense reflected in the model is the target level of performance."[56] The Smelter Agreements filed in this case allow the Smelters to terminate the agreements if Smelters conclude Big Rivers cannot achieve the financial model filed with the Commission in December during the first five years.[57] If interest rates in the final credit agreements and resulting interest expense turn out to be higher than assumed in the financial model for whatever reason, the calculated TIER will fall, other things equal, and Big Rivers will not have met the "target level of performance" which would permit the Smelters to terminate the agreements. Finally, the TIER adjustment payments from the Smelters is capped and limited, such that the remaining "uncapped" costs of achieving a certain TIER level will fall back to remaining customers other than the Smelters. The Commission should note that the financial projections show that the smelter rate subject to TIER adjustment is very close in many years to the cap, with the consequence that if there is a negative deviation from the financial projections, the smelter cap would be reached, and consumers would become responsible for maintenance of the desired TIER level. (Compare: line 36, "Smelter Rate subject to TIER Adjustment" to line 35, "Bandwidth Ceiling", at page 12 of the Financial Model, "Smelter Rate Structure".)

Investment Grade Credit Ratings

Q. DOES BREC STATE INVESTMENT GRADE CREDIT RATINGS FOR ITS DEBT ARE IMPORTANT?

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[54] Id., 13.b.

[55] Fayne testimony, page 16, lines 6-7.

[56] Smelters' Response to AG Request No. 1-19.

[57] Exhibit 20, Smelters' Retail Agreements, Article 7 2 4(a).

A. Yes. BREC states this is a requirement of the Unwind transaction, and investment grade credit ratings are implicit in BREC's financial modeling. I agree that an investment grade credit rating is a crucial objective for a public utility. Standard and Poor's defines its credit rating as "a letter grade that reflects Standard & Poor's opinion of the ability and willingness of an entity to meet its debt and other obligations on time and in full"[58] and other rating agency definitions would be identical in direction. A public utility normally should have a higher, rather than lower, ability and willingness to pay its obligations in full and on time. S&P, Moody's and Fitch employ different "grades" but the underlying concept is the same. An investment grade credit rating can be understood as being in contrast to speculative grade ratings. This can be illustrated by using Standard & Poor's "rating scale":[59]

Investment Grade	
AAA	Extremely strong
AA	Very Strong
A	Strong
BBB	Adequate
Speculative Grade	
BB	Vulnerable to nonpayment
B	More Vulnerable, but retains capacity to meet obligations
CCC	Vulnerable
CC	Highly Vulnerable
D	Default

Q. HAS BREC OBTAINED INVESTMENT GRADE CREDIT RATINGS AT THIS TIME?

A. No. BREC apparently has not sought indicative credit ratings from any of the credit rating entities (Moody's, S&P, or Fitch), or otherwise obtained credit ratings despite internal indications that it intended to do so. **[BEGIN BREC/MEMBER COOPERATIVE CONFIDENTIAL]** [redacted]

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[58] BREC response to OAG No. 1-60, S&P's Rating Methodology for U.S. Power Cooperatives: An Overview, November 2, 2006, page 3.

[59] Id.

[60] Cooperative response to OAG Supplemental No. 1, page 31.

[END BREC/MEMBER COOPERATIVE CONFIDENTIAL] Meetings BREC had scheduled with S&P and Moody's in early March have been postponed.[61] Presumably this stems from the difficulties BREC has experienced in executing its original plan for refinancing/restructuring its debt, along with other scheduling considerations such as current lack of completion of negotiations with creditors. The Application states BREC will "begin the process to obtain investment grade credit ratings on the debt secured by its generating assets from Standard & Poor's and Moody's rating agencies"[62], after formal application is made for approval of indebtedness upon completion of negotiations with creditors. This places the burden on the Commission and the parties to make multiple assessments of this transaction at various stages. Ultimately, it is possible that the Commission and the parties will have to address this matter again, even after and assuming the Commission approves a not-yet-presented formal application for approval of issuance of indebtedness, since BREC will not have obtained its credit rating at that point. If the rating agencies do not provide an investment grade credit rating at that point, presumably changes impacting the financial projections would be required in order to gain the investment grade rating, which changes would require further review by the Commission and the parties. BREC has observed that **[BEGIN BREC/MEMBER COOPERATIVE CONFIDENTIAL]** [redacted] **[END BREC/MEMBER COOPERATIVE CONFIDENTIAL]**

Q. WHAT IMPORTANCE DO INVESTMENT GRADE CREDIT RATINGS HAVE FOR THE FINANCIAL MODEL WHICH THE JOINT APPLICANTS HAVE PRESENTED IN THIS CASE?

A. The financial model as presented is an integrated scenario that assumes among other things a pro forma debt restructuring, recasting and reducing the RUS debt, and issuance of new public debt—all at estimated/forecasted interest rates. BREC believes that the modeled results of this integrated scenario will be sufficient to obtain an investment grade credit

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[61] BREC response to OAG Supplemental No. 119.

[62] Application, paragraph 66.

rating. A major contingency is that the integrated scenario is changed, and the modeled results are not sufficient to obtain an investment grade credit rating (or approval by the Smelters). In fact, BREC has changed its financing plan to defer the issuance of public debt, and reduce the prepayment of RUS debt by more than 50%. The interest rates for the new public debt are lower than the RUS rates (RUS interest is fixed at 5.82% in the model, while the public debt interest cost is assumed to carry fixed interest rates of 5.82% for the "short term" tranche, and 5.92% for the long term tranche). The estimated interest rates for the public debt are "indicative" rates from Goldman Sachs as of April 23, 2007. However, this modeled financing scenario is not reflective of the recently filed alternative financing plan, which alters BREC's financial structure. It has not been demonstrated that the financial impacts of this altered financial structure will be acceptable to the Smelters, or earn an investment grade credit rating from the credit rating entities. The Smelter agreements allow the Smelters to terminate the agreements prior to the effective date based on business judgment if the Smelters determine that the financing plan "would materially affect the calculation of the TIER adjustment", and that "actual interest cost would be more than 15 basis points in excess of [estimated interest costs]". (Smelter Retail Agreement, section 7.2.4). 15 basis points is a tight criteria. As stated in the Application:

> The need to obtain financing at reasonable rates drives the condition to closing in the ~~Termination Agreement that Big Rivers obtain an investment grade rating. The~~ TIER Adjustment mechanism in the Smelter Agreements supports a 1.24 TIER, which Big Rivers and its financial advisors believe is important to achieve the appropriate investment grade ratings.[63]

If interest expense is higher than in the model, achieved TIER is lowered absent Smelter contributions through the TIER adjustment mechanism. If TIER is lowered, then achievement or maintenance of an investment grade credit rating is impeded or prevented absent rate increases or cost reductions.

Q. DID YOU ATTEMPT TO MODIFY THE MODEL INPUTS TO REFLECT THE ALTERNATIVE FINANCING SCENARIO IN ORDER TO ASSESS THE IMPACT ON INTEREST EXPENSE, TIER, TIER ADJUSTMENT CHARGES AND RATES?

[63] Application, paragraph 52.

A. Yes, but I found that the model version we were provided would not accept changed debt inputs and yield a revised pro forma financial projection. Changing the debt inputs generated a plethora of Excel spreadsheet "#NUM!" errors.

Q. IS BREC EXPOSED TO INTEREST RATE RISK?

A. Yes. This risk pertains to the use of variable rate borrowing instruments, short term borrowing or uncommitted planned borrowing. The risk in this context is that interest rates will continue to rise, thus causing BREC to bear increased fixed interest charges associated with higher interest for any debt which is carried at the variable rate (e.g., revolving credit or lines of credit), or bear higher interest costs at the time short term financing must be refinanced, or long term financing consummated. These higher interest expenses must be paid—thus the term "fixed" in this context, and would preempt cash use that had been planned or is necessary for other purposes (e.g., capital investment or operating expenses). These higher interest expenses would also impact calculated TIER and TIER Adjustment charges to the Smelters, including going outside the "bandwidth" which the Smelters must pay, thus causing additional costs for consumers.

Q. DOES BREC RECOGNIZE CONDITIONS IN THE CREDIT MARKETS, UPON WHICH ITS RE-FINANCING DEPENDS, AS BEING STABLE OR UNSETTLED?

A. BREC has stated that current credit market conditions are unsettled, and I agree with this assessment. This of course affects BREC's ability to achieve its refinancing objectives, and compels BREC to search for alternatives. Alternative financing considerations are the subject of BREC's recently filed Amendment to the Application. BREC states that "the sole reason driving Big Rivers to explore financing alternatives is the unsettled condition in the credit market and <u>the extremely wide credit spreads</u>."[64]

Q. PLEASE ADDRESS THE SUBJECT OF CREDIT SPREADS.

A. This term is a reference to the margin or premium charged as a component of the total interest rate, over and above a "risk free" rate of interest such as that which is associated with United States Treasury bonds, which are presumed to be backed by the full faith and credit of the United States government and bear no risk of default. The credit spread or premium or margin reflects the unique business and financial risks of the borrower, but is

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[64] BREC response to OAG Supplemental No 116, <u>emphasis added</u>

also dependent on market conditions. As noted by BREC, credit market conditions are currently "unsettled" as a result of events dating back to Summer 2007, and the substantial ripples from the sub-prime mortgage problems. It is not clear when the credit markets will "settle", and more importantly, it is not clear what credit spreads will be at the point in time when the credit markets do in fact "settle". Market conditions may be such at that point in time that margins settle at levels well above what has been prevalent in recent years as investors demand higher compensation for perceived risks.

Q. DO YOU HAVE A CURRENT EXAMPLE FOR THE COMMISSION OF OTHER COMMISSIONS FACING THE CONSEQUENCES OF UNEXPECTEDLY WIDE CREDIT SPREADS?

A. Yes. In January 2007, FairPoint Communications struck an agreement with Verizon Communications to acquire Verizon's Northern New England (Maine, New Hampshire and Vermont) telecommunications operations. The proposed transaction was supported before the three state commissions by the Joint Applicants by financial projections that extend to 2015, and proposed bank loan and bond financing. The state commissions (among other things) approved a stipulated level of borrowing at interest rates averred to by FairPoint. The transaction and related financing is to close March 31, 2008. Early in the week of March 24th, FairPoint informed certain Commissions that the interest rate on the bonds would be much higher (approximately 11% per annum) than anticipated in the company's financial model as presented in support of stipulations among the parties, which were also the core of state commissions' approvals of the transaction. Then late in the day on Wednesday March 26th, it became known that the interest rate on the bonds would actually be much higher than that—13.5% per annum. According to S&P, "Terms for the B+/B3 rated deal, ... were forced 200 bps wide of initial guidance, to 13.5%, amid the highly challenging market conditions ..." State commissions were already concerned about the financial projections and financial viability of FairPoint following the transaction as evidenced by the Commission orders. The consequence of this unexpectedly very large margin on the bond issue over what was projected and anticipated results in increased interest expense of over $27 million annually. Also, as a consequence, the state commissions were faced with a Hobson's choice regarding a transaction that had been approved. Hearings on this issue were held on Friday, March 28th in Maine, and on Sunday

March 30th in New Hampshire. At this late date (two business days before the planned closing date of the transaction), there were not any viable alternative remedies available to the commissions. I am familiar with the details of this matter as a result of my participation in both the Maine and New Hampshire cases, including pre-filed testimony supported under cross examination, on behalf of the Office of Public Advocate and Office of Consumer Advocate (respectively). In my view this clearly illustrates a risk to ratepayers and to the Public Service Commission of Kentucky of approving the proposed transaction here with financing arrangements left to the future. It is not at all clear that interest rate margins will revert to previous low levels, or remain high relative to those levels for the foreseeable future. This uncertainty or risk clearly affects BREC's future under the proposed transaction.

Q. HAVE INTEREST RATE MARGINS BEEN AT RELATIVELY LOW LEVELS, COMPARED TO HISTORICAL AVERAGES?

A. Yes. This is illustrated by the following for "high yield" bonds:

- "The flood of new debt in the high-yield bond market hasn't widened risk premiums. Within the past week, the Lehman Brothers U.S. High yield index showed risk premiums hit a record low of 232 basis points over Treasurys." "The premium investors charge companies to compensate them for default risk has shrunk to reach near or record lows in May, even though the new debt raised is being used to finance activities that typically bode poorly for bondholders: stock buybacks and leveraged buyouts."[65]

- "In recent months, lower credit bonds—conventionally defined as BB+ and below—have traded at a smaller risk premium (as compared to U.S. Treasuries) than ever before in history. Over the past 20 years, this margin averaged 5.42 percentage points. Shortly before the Asian crisis in 1998, the spread was hovering just above 3 percentage points. Earlier this month, it touched down at a record 2.63 percentage points. That's less than 8% money for high-risk borrowers."[66]

- "Several factors underlie the new pushback against buyout financings. One is the growing awareness that investors have

[65] "Demand Continues for Debt; Investors Rush in to Take on Risk", The Wall Street Journal, June 1, 2007.

[66] "The Coming Credit Meltdown", The Wall Street Journal, June 18, 2007.

been demanding very little in return for the risk they have accumulated in buying buyout-related loans and debt. Yields on junk bonds, when compared with ultrasafe U.S. Treasury securities, hit historic lows around a month ago. ... In addition to demanding higher interest rates, investors are resisting many bonds and loans that they believe to be too easy on borrowers. Investors have rejected a number of recent deals that included "payment-in-kind" provisions, which allow companies to postpone debt payments to their lenders if they run short of cash. Investors also have rejected loans that are light on common performance requirements, known as covenants. ... Banks in several cases have been stuck holding portions of loans or bonds they planned to parcel out to investors, something that could make them more selective in underwriting deals."[67]

- "Financial advisors say this marks a good time for investors to re-evaluate their high-yield holdings. Currently the average high-yield bond is giving a yield of only about three percentage points more than U.S. Treasury bonds, which are among the safest investments available. For comparison, as recently as 2002, that gap was around nine to 10 percentage points."[68]

- "While the spread between junk bonds and a 10-year Treasury note—which shows how much lenders charge for added risk—has increased by almost a percentage point since the end of May to 3.43 percentage points, its still well below the long-term spread of 5 percentage points."[69]

While the above pertains to non-investment grade bonds, the impact is the same for investment grade bonds—margins or spreads are wider for those debt instruments as well, as evidenced by BREC's recent experience ("extremely wide credit spreads") regarding its original financial restructuring plan.

BREC's Material Dependence on the Smelters' Load

67 "Market's Jitters Stir Some Fears for Buyout Boom: Takeover-related Debt Gets Chilly Reception; Hearing 'Wake up' Call", The Wall Street Journal, June 28, 2007.

68 "The Junkyard Dogs Investors in Some Funds: Rising Risk Premiums Hit High Yield Holdings; 'I wouldn't be an Owner'", USA Today, July 10, 2007, P-23.

69 "Corporations have Trouble Borrowing", USA Today, July 24, 2007, page 4B.,

Q. WHAT PROPORTION OF BREC'S PROJECTED TOTAL REVENUE IS DERIVED FROM THE SMELTER AGREEMENTS?

A. The percentage varies by year and is 53.5% of projected total revenues in 2009, 60% in 2011, and 57.4% in 2018, for example. By another measure, BREC notes that "56% of its Members' demand [is] associated with" the Smelters.[70]

Q. WHAT PROPORTION OF THE "TOTAL FINANCIAL BENEFIT OF THE UNWIND TRANSACTION" TO BREC IS ESTIMATED TO STEM FROM THE SMELTER AGREEMENTS?

A. According to the Blackburn testimony at page 12, the total financial benefit of the unwind transaction to BREC is $950 million, of which $327 million is due to "increased power purchase payments from the Smelters". The $327 million amount is the present value of annual sums in excess of the large industrial rate for additional margin, TIER surcharge payments, and other surcharge payments.

Q. IS THIS ADDITIONAL $327 MILLION IN REVENUE (PRESENT VALUE) FROM THE SMELTERS CERTAIN TO BE EARNED BY BREC?

A. No. BREC states the $327 million present value figure "is arrived at by calculating the amount of payments from the Smelters that exceed what would be collected from Big Rivers' large industrial tariff at a 98% load factor. ... the Smelters pay at least 25 cents over the large industrial tariff, the cost of the 1.24 TIER and surcharges that flow back to the Members to offset some of their fuel costs."[71] The $327 million present value figure depends on its assumed inputs: the discount rate, and per period cash flows. It appears BREC uses a discount rate of approximately 5.4% for this calculation. The Commission should note that per period cash flows assumed for the TIER and Surcharges in the model are smaller in the early years (2008-2012), and larger in later years. The present value of later year payments are less than early year payments due to time value of money. The Smelters are able to terminate the contracts under stated circumstances, so the actual receipt by BREC of the later years' cash flow is uncertain. If Smelter payments are assumed to cease after 2012, the present value of payments to that point is substantially less--$86

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[70] Application, paragraph 53.

[71] BREC response to OAG No. 1-67

million, or 26% of the $327 million. Please see attached Exhibit DB-3 for a comparison of these present values. This is one instance which illustrates the fact that the benefits of the proposed transaction tend to be "front end loaded" into the early years, while risks and uncertainties are prevalent in the later years. While the Smelters do make additional payments in the early years, continued and larger payments in subsequent years must be viewed as more uncertain for at least two reasons—first, there is some possibility that the Smelters close operations in Kentucky due to business and cost conditions; and, second over time the Smelters can use advocacy positions before policy makers including the Commission to reduce the amounts paid below what is projected in the financial model.

Q. WHAT IS THE BASIS FOR THE RATES TO BE CHARGED TO SMELTERS OVER THE TERM OF THE PROPOSED RETAIL AGREEMENT?

A. The basis for the rates is a cost basis, rather than a market rate basis. A consequence of this is that to the extent that BREC's operating, capital and financial costs cause increased rates, this is flowed through to the smelters, and to the extent those increases make the smelter operations uneconomic in the commodity markets, the operations could be shut down and the loads lost to BREC. Smelter payment obligations as defined by the Smelter Agreements are driven by a very complex set of calculations.

Q. HAVE YOU REVIEWED THE SMELTER AGREEMENTS IN EXHIBIT 20?

A. Yes, I have reviewed them from a non-legal perspective.

Q. WHAT IS THE EFFECTIVE DATE OF THE SMELTER RETAIL AGREEMENTS?

A. The Agreements have not been executed, and are not effective at this time. The Retail Agreements, Article 6, sets out the conditions for occurrence of the effective date. I summarize the conditions as follows:

1. The Unwind Transaction will have been consummated (6.2.2);
2. The Wholesale Agreement shall be acceptable to each individual Smelter (6.2.4);
3. Each Smelter's Wholesale and Retail agreements will have been executed and delivered to the parties (6.2.8);
4. RUS shall have consented to the transactions and all arrangements and agreements necessary to implement the transactions (6.2.10);

5. Guarantee by the Smelter Parent shall have been delivered (6.2.5);
6. Representations and warranties of the parties will continue to be correct as of the effective date, and certificates to such effect shall have been received (6.2.1);
7. Other documents shall have been delivered as required (6.2.3 and 6.2.6); and,
8. No further authorizations or approvals are required (6.2.7 and 6.2.9).

Q. UNDER WHAT CONDITIONS CAN THE RETAIL AGREEMENT BE TERMINATED PRIOR TO THIS EFFECTIVE DATE?

A. The Retail Agreement can be terminated prior to its effectiveness for the following reasons, as stated in Article 7:

1. Failure to satisfy the conditions to Effective Date (above) (7.2.1);
2. If the Unwind Transaction will not be consummated (7.2.2);
3. If KPSC orders modify pricing or material terms of these agreements, BREC's ability to recover costs from Smelters, or non-Smelter ratepayers (7.2.3);
4. Business judgment (7.2.4), such that
   a. "Big Rivers' operations cannot produce during the first five years .... the charges projected in Big Rivers' financial model ...";
   b. Smelters can terminate if "material adverse change in the production facilities", or if "material change in [external] economic or business factors ... that would have a material adverse financial effect on" the Smelter; and,
   c. Smelters determine that the financing plan "would materially affect the calculation of the TIER adjustment", and that "actual interest cost would be more than 15 basis points in excess of [estimated interest costs] or other terms or conditions are materially different than those estimated".

BREC response to OAG No. 1-79 provides a complete discussion of applicable terms, conditions and circumstances for Smelter termination of the agreements.

Q. UNDER WHAT CONDITIONS CAN THE RETAIL AGREEMENT BE TERMINATED AFTER THE EFFECTIVE DATE?

A. Per 7.3.1 (a), the Agreement can be terminated "in connection with the termination and cessation of all aluminum smelting operations at the" Smelter operation in Kentucky, but such termination may not be effective prior to December 31, 2010.

Risk Management

Q. DOES BREC PLAN TO FORM A NEW ENTERPRISE RISK MANAGEMENT FUNCTION?

A. Yes. This function is the subject of a new company policy adopted in June 2007, and will focus on risk identification, evaluation and mitigation of risks. The company policy document is included as Exhibit MAB-5 to the Bailey testimony. Risk management and strategic planning are intertwined. "The ERM and strategic planning functions of BREC will facilitate the development and monitor[ing of] the implementation of a strategic plan that will incorporate enterprise risks that require additional strategic focus."[72] While the Board of Directors is ultimately responsible for risk management, senior management of BREC constitutes the Internal Risk Management Committee (IRMC), and is responsible for risk management activities at the working level. The IRMC is chaired by the VP (or Director) of Enterprise Risk Management/Chief Risk Officer, but as a non-voting member. This person has not yet been hired—"Big Rivers intends to bring on board an industry veteran to serve as either Vice President or Director Enterprise Risk Management & Strategic Planning/Chief Risk Officer."[73] This position, and the risk management function and responsibility are critically important for BREC's future. There are substantial inherent risk exposures for BREC going forward, which will need to be understood, addressed and mitigated to the extent possible. BREC may also be able to obtain risk management support in certain areas from ACES Power Marketing (APM).

BREC has noted it is "unique to other generation and transmission cooperatives in that it has one Member with two large aluminum smelters in its customer base that operate at a

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[72] Exhibit 5, Direct Testimony of Mark Bailey, Exhibit MAB-5, page 6

[73] Exhibit 5, Direct Testimony of Mark Bailey, page 9, lines 7-9

continuous 98% load factor."[74] Also, BREC notes **[BEGIN BREC/MEMBER COOPERATIVE CONFIDENTIAL]** [redacted] **[END BREC/MEMBER COOPERATIVE CONFIDENTIAL]** Some important risk areas are identified as standing agenda items for the IRMC, as follows:

- "Current commodity market strategies;
- Power cost uncertainty;
- Level of exposure to non-member transactions;
- Production strategies and exposures;
- Financial strategies and exposures;
- Environmental strategies and exposures;
- Counterparty contract and credit exposure."[76]

Also, the Enterprise Risk Management policy identifies the scope of business activities to be addressed by risk management as:

- "Commodity price risk;
- Volumetric risk;
- Power and fuel delivery risk;
- Operational risk;
- Financial risk;
- Environmental and regulatory risk;
- Counterparty contract and credit risk;
- Organizational risk;
- Board and officer risk;
- Safety risk."[77]

These risks are further detailed in Appendix A to the ERM policy document.

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[74] BREC response to OAG No. 1-20

[75] BREC response to Supplemental OAG No. 103, page 40

[76] Direct Testimony of Mark Bailey, Exhibit MAB-5, page 4.

[77] Id., page 6.

Q. DOES THE PROPOSED UNWIND TRANSACTION EXTEND RISKS IN TIME?

A. Yes. Big Rivers seeks approval to amend its wholesale power contracts with the member cooperatives, extending the term of such contracts to 2043. "This term extension will accommodate the maturities of new debt or debt refinancing that Big Rivers anticipates in connection with the Unwind Transaction, and may allow for the maturity of any other debt that Big Rivers might incur in the near term without another round of Member wholesale power contract amendments."[78] Risks are extended in time by this proposed contract amendment at a time when uncertainties are increasing regarding coal-fired generation of electricity due to environmental issues. The Commission may find it inadvisable to extend such risks in time.

<u>Summary of Conclusions</u>

Q. PLEASE STATE CONCLUSIONS YOU HAVE DRAWN FROM REVIEW OF THE APPLICATION, TESTIMONY, RESPONSES TO DISCOVERY QUESTIONS, AND RELEVANT STATUTES.

A. I draw the following conclusions:

1. The Joint Applicants have placed the parties and the Commission in the position of having to address an Application which is incomplete in material respects. The Application is contingent on its own terms on matters which are presently unfulfilled and unknown to the parties or the Commission. The transaction requires accomplishment of due diligence on the generating facilities by BREC which has not been completed; earning of an Investment-grade credit rating which has not yet been accomplished; filing of many financing documents which have not yet been negotiated/executed or provided; reaching contractual agreement with a large industrial customer (Southwire); and, obtaining the consents of various parties (including approvals and releases from the City of Henderson) to the financing and transaction, the cost of the consents are presently unknown to the parties and the Commission (and do not appear to be accounted for in the financial model). The Commission could reasonably hold this proceeding in abeyance until these matters have

[78] Application, paragraph 50.

been accomplished and addressed through additional discovery and analysis presented before the Commission. Since the "proposed issue" is not known to the Commission at this time, the Commission cannot find it to be necessary for performance of the utility of its service to the public. Further, since the "proposed issue" is unknown, and its financial impact is unknown, the Commission cannot find that the proposed issue will not impair the utility's ability to perform its service to the public.

2. The claimed benefits of the proposed transactions occur in the very early years, while the substantial risk exposures occur later. BREC's view that a rate increase is needed is deferred by the $75 million Economic Reserve account. Further, depreciation rates are known by BREC to not be current and in fact have been depressed to obtain smelter agreement. It is known that depreciation rates will need to be addressed in a planned general rate application. The unique components of Smelter contribution are through surcharges and TIER adjustments. In the early years, the Smelters are projected to realize TIER rebates, with TIER payments projected to begin in 2011. The Smelters can seek through the policy process and the general rate case which is planned for 2010 to alter and reduce the surcharges and adjustments, thus reducing dollars paid by the Smelters and increasing payments from other consumers (all things equal). Other risk exposures are outlined below.
3. BREC states that revenues lost if the Smelters leave "are more than recovered by alternative sales into the market".[79] While this is true given the assumptions utilized, it is also true that rates for consumers are substantially increased at the same time by elimination of offsets to rates paid by the Smelters under the Smelter agreements, and by modeled general rate increases.
4. The Commission may reasonably have concerns about BREC's financial viability going forward, given its exposure to risks from future events such as credit market uncertainties, the large smelter load disappearing, current lack of due diligence completion coupled with concerns about the condition of the facilities, and environmental regulations including carbon legislation. BREC notes that **[BEGIN BREC/MEMBER COOPERATIVE CONFIDENTIAL]** [redacted]

[79] BREC response to Commission staff No. 1-10.

[redacted] **[END BREC/MEMBER COOPERATIVE CONFIDENTIAL]**

5. Big Rivers' ability to effectively and explicitly manage risks facing the enterprise is crucial in order to ensure and protect its financial viability. BREC's enterprise risk management direction is laudable, but it must be comprehensive in scope, and well-implemented.
6. Achievement of BREC's projected financial results materially depends on direction taken on environmental concerns, which are largely outside of BREC's control. The financial model includes impacts only for present environmental requirements, but no impacts are included for potential future carbon/greenhouse gas regulations or regulations pertaining to mercury. Further, environmental cost increases would significantly impact Smelter rates such that continued operation could become uneconomical.
7. The interests of the Smelters do not align in all respects with the interests of the general body of ratepayers. Yet the Smelters have a direct and continuing ability to affect BREC's operational and financial decisions through the Coordinating Committee and other means. One example of where Smelter interests may be contrary to BREC interests in that Smelters prefer to defer/depress current costs in favor of recovery "later" (e.g, depreciation). Also, the smelters have **[BEGIN SMELTER CONFIDENTIAL]** [redacted] **[END SMELTER CONFIDENTIAL]**
8. This case may be considered as requiring consideration of two alternatives, each of which has substantial uncertainties. Neither alternative (continuing the present mode of operation however it may later unfold, versus accepting the Joint Applicant's application) is free of difficulties or concerns. However, I conclude the balance should fall in favor of the efforts of the Joint Applicants, subject to the certain concerns and considerations expressed here.

The Commission and the Office of Attorney General will need to be watchful and fully informed on particular issue areas, especially in the area of risk management.

Recommendations

Q. DO YOU RECOMMEND THAT THE COMMISSION APPROVE THE TRANSACTIONS AS PROPOSED BY THE JOINT APPLICANTS?

A. My recommendation at this time is provisional, since final information on consent agreements and fees, the nature of any agreement with the City of Henderson (and related financial impacts associated with releases and approvals), credit ratings and credit restructuring agreements and financial implications is not known at this time. In my view, these matters should have been settled first so they could be provided to the Commission as part of a comprehensive filing. Instead the parties have been required to address a partial filing, which leaves many crucial matters unknown and subject to later serial and piecemeal additions to the Application. I therefore make a provisional recommendation that the Commission approve the transactions, but with limited enthusiasm, and with certain conditions and understandings. This recommendation also gives weight to the straightforward analysis of BREC and its member cooperatives of the "pros and cons" of the proposed transaction, as provided by the member cooperatives in response to OAG Supplemental No. 1.

Q. WHAT CONDITIONS DO YOU RECOMMEND THAT THE COMMISSION INCLUDE WITH APPROVING THE TRANSACTION?

A. I recommend the following conditions:

1. BREC has presented its financial model results as the "base case" upon which its decisions were based. Yet the application is incomplete and there are pending matters which may affect this "base case". The Commission should require that the "base case" rates and results be maintained past resolution of the pending matters such that if resolution of a matter (e.g, due diligence finalization, credit restructuring, City of Henderson matters, or consent fees and agreements) would unfavorably impact the "base case" rates and results, E.ON and/or the smelters must step forward to fund and eliminate those unfavorable impacts in order to restore the "base case" projections.
2. BREC shall not waive any conditions to closing without Commission approval.

3. BREC shall use the March 11, 2008 Stone & Webster Final Report in addition to its own resources to finalize its due diligence on the generating facilities and sites.
   a. BREC shall reconcile **[BEGIN SMELTER CONFIDENTIAL]** [redacted] **[END SMELTER CONFIDENTIAL]**
   b. BREC shall provide its final due diligence report to the Commission and the parties, and include the reconciling information and estimated costs, along with its recommendation as to when and how each item should be addressed.
   c. BREC shall provide to the Commission and the parties a revised run of the Financial Model which incorporates these items in a revised Production Work Plan, BREC's recommended method of addressing each item, and BREC's estimated cost of doing so, for Commission approval prior to closing the transaction.
4. BREC shall fund, initiate and maintain a comprehensive risk management plan and program, which includes the ability to address impact of contingencies including, but not limited to, fuel prices, cost exposure for environmental remediation programs (both existing and contemplated), and any other material risks pertaining to BREC.
5. Prior to any filing by BREC to increase its rates, BREC shall file with the Commission a comprehensive report on identified risks and steps taken under its Risk Management program to address or mitigate those risks.
6. BREC shall provide the Commission with minutes and documents from each meeting of the Coordinating Committee at least through 2011. Upon request of either the Commission, BREC's required provision of minutes and documents shall be extended.
7. In the event of future changes in environmental regulations compliance which BREC determines will have a material financial effect on it, BREC shall report on a timely basis to the Commission of the nature and expected cost of compliance with changed environmental regulations, including financial projections modified to include compliance costs and impacts on rates and revenues.

8. BREC shall file with the Commission projected budgets on the same schedule as management adopts annual budgets each year through 2013 and shall pay, if so requested by the Commission, for a third party to review same. BREC shall provide and include in the filing explanation of differences between that year's budget and the projected amounts for that same year in the final version of the Financial Model considered by the Commission in this case.
9. BREC will continue to employ at least the same level of workforce, with comparable if not better skill and expertise, as it currently does, or notify the Commission if BREC has concluded it would be imprudent to do so, stating the reasons why BREC believes it to be imprudent.
10. BREC will negotiate in good faith with IBEW during any collective bargaining agreements.
11. BREC shall advise the Commission and the Attorney General of any material changes to its financing arrangements, on a timely basis.
12. BREC shall advise the Commission of any changes to RUS' criteria for the financing of both new coal-fired plants, and regarding any financing relating to existing coal-fired plants, on a timely basis. In the event of any such changes, BREC shall supply a plan for assessing the impact and ramifications (if any), and how BREC will address those changes.
13. BREC shall advise the Commission of any material changes to smelter contracts, on a timely basis.
14. BREC shall advise the Commission and the Attorney General in event of any material changes in its agreements with HMPL, on a timely basis.
15. BREC shall advise the Commission in the event of any material changes in its agreements with labor unions, on a timely basis.
16. BREC shall advise the Commission and the Attorney General on a timely basis of any material events that in any way could impact BREC's ability to wheel excess power to other markets.
17. BREC shall advise Commission on a timely basis of any material changes in its generating units or their operation not included in BREC's Production Work Plan as submitted in this case and finalized by BREC's due diligence.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does at this time. I reserve the right to provide supplemental testimony at a later date to address items, information and issues that are presented by BREC at a later date to fill in incomplete aspects of the filing as it is enumerated in this testimony.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:		
THE APPLICATIONS OF BIG RIVERS ELECTRIC CORPORATION FOR: (I) APPROVAL OF WHOLESALE TARIFF ADDITIONS FOR BIG RIVERS ELECTRIC CORPORATIONS, (II) APPROVAL OF TRANSACTIONS. (III) APPROVAL TO ISSUE EVIDENCES OF INDEBTEDNESS, AND (IV) APPROVAL OF AMENDMENTS TO CONTRACTS; AND	)	CASE NO. 2007-00455
OF E.ON U.S., LLC, WESTERN KENTUCKY ENERGY CORP. AND LG&E ENERGY MARKETING INC. FOR APPROVAL OF TRANSACTIONS	)	

DIRECT TESTIMONY OF DAVID BREVITZ
ON BEHALF OF
THE ATTORNEY GENERAL

Certificate of Service and Filing

Counsel certifies that an original and ten photocopies of the foregoing Direct Testimony of David Brevitz On Behalf Of The Attorney General were served and filed by hand delivery to Stephanie L. Stumbo, Executive Director, Public Service Commission, 211 Sower Boulevard, Frankfort, Kentucky 40601; counsel further states that true and accurate copies of the foregoing were mailed via First Class U.S. Mail, postage pre-paid, to:

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this 3rd day of April, 2008

Assistant Attorney General

EXHIBIT DB-1

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2007-00455

DIRECT TESTIMONY OF

DAVID BREVITZ

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General

Mr. Brevitz is an independent telecommunications consultant, a Chartered Financial Analyst and has more than twenty-seven years of experience in government affairs and telecommunications regulation/de-regulation. He previously served in management positions with industry regulatory organizations. He is a former Chief of Telecommunications for the Kansas Corporation Commission ("KCC"). He is familiar with the details of the FCC's implementation of the Telecommunications Act of 1996, and has provided expert testimony on numerous issues including telco local division spin-offs, competition, industry and market structure, service bundles, substitutability of VoIP and wireless for local exchange service, resale, unbundled elements, TELRIC/cost studies, network modernization, access charges, rate design, cost allocations, universal service and other matters.

Professional Designation and Community Service

Mr. Brevitz has achieved designation as Chartered Financial Analyst from the Institute of Chartered Financial Analysts ("ICFA") in 1984. The ICFA is the organization which has defined and organized a body of knowledge important for all investment professionals. The general areas of knowledge are ethical and professional standards, accounting, statistics and analysis, economics, fixed income securities, equity securities, and portfolio management.

Mr. Brevitz is Past President of the Topeka Kiwanis Club (1988 – 1999). He has served numerous terms on the Board of Directors of the Club, has been recognized by Kiwanis International as a George F. Hixson Fellow, and has his name inscribed on the Kiwanis International Foundation Tablet of Honor.

Mr. Brevitz is currently serving as Treasurer of Topeka Ice, a non-profit organization organized to build an ice rink for community use in Topeka, Kansas. He also currently serves as Treasurer of the Kansas City Junior Outlaws High School Hockey team (Tier II). In addition, he has served two terms as President of the Topeka Junior Scarecrows Hockey Association and two terms as Treasurer.

Recent Relevant Experience

- **1999-Current, Kansas Corporation Commission Advisory Staff:** Mr. Brevitz is serving as advisor to the Commissioners on telecommunications technical and policy matters, including determinations on state universal service fund issues; spin-off of Sprint/United's Local Telecommunications Division (now Embarq); application of price cap regulation to Southwestern Bell-Kansas and Sprint/United Telephone (now Embarq); designation of wireless carriers and other entities as Eligible Telecommunications Carriers; arbitrations between carriers pursuant to the Federal Telecommunications Act; Southwestern Bell–Kansas' Section 271 application; pricing and costing of unbundled network elements for Southwestern Bell and Qwest; modification of the Kansas Universal Service Fund to be cost based consistent with state and federal law; adaptation of the FCC cost proxy model for intrastate use; rate rebalancing and DSL deployment; Digital Subscriber Line (DSL) matters; legislative issues; advanced services; access charge restructure; collocation; and, toll dialing parity and carrier of last resort as examples. Mr. Brevitz also serves as advisor on electric industry matters, including cases involving structure/restructure of Westar Energy and Aquila.

- **2007 to current, FairPoint/Verizon Merger/Acquisition of New England State Operations:** Mr. Brevitz is working on behalf of the Maine Office of Public Advocate to assess the proposed spin off of Verizon operations in Maine, New Hampshire and Vermont and subsequent merger with and into FairPoint Communications, in a reverse Morris trust transaction. The assessment includes evaluating financial projections of the company in support of financial viability of the proposed transaction; financial analyses associated with the proposed transaction performed by the company and investment advisors; and implications of resulting debt leverage and structure of the company as "high debt/high dividend". The Hearing Examiner's Report adopted Mr. Brevitz's financial recommendations including substantial debt ($600 million) and dividend reduction.

- **2007 to current, FairPoint/Verizon Merger/Acquisition of New England State Operations:** Mr. Brevitz is working on behalf of the New Hampshire Office of Consumer Advocate to assess the proposed spin off of Verizon operations in Maine, New Hampshire and Vermont and subsequent merger with and into FairPoint Communications, in a reverse Morris trust transaction. The assessment includes evaluating financial projections of the company in support of financial viability of the proposed transaction; financial analyses associated with the proposed transaction performed by the company and investment advisors; and implications of resulting debt leverage and structure of the company as "high debt/high dividend". The Commission has made preliminary determination in favor of Mr. Brevitz's financial recommendations.

  April 2007, PURC Advanced Training Course on Regulatory Economics and Process: Interconnection, Pricing and Competition: Mr. Brevitz developed and presented three courses to members of the National Telecommunications Commission from Thailand. The courses covered accounting separation, case study on a rate proposal, and principles and practices for rate rebalancing.

- **January, 2007, 21st International Training Program on Utility Regulation:** Mr. Brevitz developed and presented training sessions on accounting separation, rate rebalancing (case study), and universal service obligations to the semi-annual training program for regulatory agency staff and commissioners worldwide. The training program is provided by the Public Utilities Research Center at the University of Florida in Gainesville.

- **2006-Current, Telecommunications Training for Regulatory Agency for Telecommunications (RATEL) in Serbia:** Mr. Brevitz is working to assist RATEL in implementation of new polices designed to open telecommunications markets in Serbia to competition. Issues being addressed include cost orientation of prices (rate rebalancing), universal service funds, interconnection, administrative procedures, internet telephony, and spectrum management.

- **2006-2007, Embarq UNE Loop Pricing Application:** Mr. Brevitz assisted the Bureau of Consumer Protection in the Nevada Attorney General's office in its assessment of Embarq's proposal to increase rates for the unbundled loop. This work included assessment of Embarq's proposed UNE loop cost model and its inputs, FCC orders which speak to TELRIC costing and UNE pricing, and use of the mapping program to support Embarq's proposed cost model.

- **"Assessing Pricing Behavior Under Deregulation"**: Presentation at the NASUCA Mid-Year Meeting, June 14, 2006, Memphis Tennessee.

  2006 Spin-off of Windstream from Alltel: On behalf of the Kentucky Attorney General (Office of Rate Intervention), Mr. Brevitz formulated discovery, and analyzed and addressed information relevant to the proposed spin-off of the local telecommunications operations from Alltel Corporation and subsequent merger with Valor Communications. Prefiled testimony was provided before the Kentucky PSC addressing the excessive debt burden placed on "SpinCo" by Alltel; conflicting company claims regarding merger synergies; lack of basis for claimed increased buying power; and non-arms-length nature of decisions and transactions in the proposed spin-off.

- **2005 Rate and Revenue Requirement Review of Saco River and Pine Tree Telephone Companies**: On behalf of the Maine Public Advocate's Office, Mr. Brevitz addressed revenue requirement levels for both companies, including detailed review of expense levels and trends, expanded calling plan criteria and data, and detailed review of holding company organization and charges between affiliates.

- **2005 Price Deregulation of Basic Local Exchange Service**: On behalf of AARP, Mr. Brevitz provided comments before the Public Utilities Commission of Ohio regarding final rules to implement procedures for addressing price deregulation applications. The comments addressed the need for effective competition to be demonstrated before approving price deregulation of BLES; market segmentation between stand-alone BLES and service bundles; barriers to entry; current competitive market conditions and whether "many sellers" exist; functionally equivalent and substitute services; and other related matters.

  2005 Spin off of "LTD Holding Company" from Sprint Nextel: On behalf of the Nevada Bureau of Consumer Protection, Mr. Brevitz led a team to analyze the proposed spin-off from a technical and public interest perspective under Nevada statutes. Issues addressed included: asset transfers to LTD Holding Co.; levels of debt to be placed on LTD Holding Co.; "normal" levels of debt for Sprint's Local Telecommunications Division; financial and cost of capital implications of the spin off; impact on LTD's ability to compete and other competitive trends; and accounting issues such as division of pension assets and pension liabilities.

- **"Telecommunications Convergence: On Duopoly?"**: Presentation at the NASUCA Mid-Year Meeting, June 15, 2005, New Orleans, Louisiana.

- **2005 Intrastate Deregulation Proposal of SBC Oklahoma**: On behalf of AARP, Mr. Brevitz filed testimony addressing SBC Oklahoma's proposal to deregulate pricing of almost all intrastate services (E911 and access services were excepted). The testimony responded to SBC Oklahoma assertions regarding significant retail competition on a widespread basis, openness of markets, barriers to entry and exit, reasonable interchangeability of use of cellular and VoIP services for basic residential services, market share analysis, and competitive trends including CLEC responses to the elimination of UNE-P, access line losses. The testimony further analyzed the actions, opportunities, and competitive responses of SBC Oklahoma and its corporate affiliates, observed public safety deficiencies of cellular and VoIP services, and market trends converging on duopoly.

- **2004 to 2005: Alternative Regulation Plan Filing by Verizon Vermont:** Mr. Brevitz assisted the Vermont Department of Public Service in assessing matters included in the Vermont Public Service Board's assessment of proposed changes to the Alternative Regulation Plan applicable to Verizon Vermont. Prefiled testimony addresses matters including assessment of competition and modes of competition, VoIP/wireless substitution, continuation of direct assignment practices under the FCC's separations freeze, jurisdictional cost allocations, rate flexibility, and UNE availability and commercial agreements with CLECs.

2005 UNE Loop Cost Proceeding: On behalf of the Arkansas Public Service Commission General Staff, Mr. Brevitz filed testimony which analyzed SBC Arkansas' proposed increased UNE loop rates, and UNE loop model and shared and common cost model inputs and outputs, including fill factors, defective pairs, IDLC, DSL expenses, and retail related costs.

- **2004 Mass Market Switching Reviews under the FCC Triennial Review Order**: Separately for the Arkansas Public Service Commission staff, and the New Mexico Attorney General's office, Mr. Brevitz provided analysis and two-step evaluation under the FCC's Triennial Review Order ("TRO") of impairment in access to local circuit switching for mass market customers. The evaluations were done on a granular, market-specific basis. The evaluations determined whether unbundled local circuit switching (and by extension, the UNE-Platform) must continue to be provided as an Unbundled Network Element by incumbent local exchange companies.

- **2004 OSIPTEL/Peru**: Worked with OSIPTEL (telecom regulator in Peru) to analyze barriers to competition in Peru. Presented workshop and training materials regarding the Economic Aspects of Competition Regulation for Public Utilities, which addressed concepts of market power, dominance, cross subsidies, essential facilities, ex ante versus ex post regulation, asymmetric regulation.

- **2003 to 2005: Cable & Wireless Rate Adjustment/Barbados Fair Trading Commission**: Mr. Brevitz advised the FTC and its staff regarding the application of C&W Barbados to increase domestic revenues and institute local measured service, and providing related analyses. The Company's filing was in part designed to enable Price Cap regulation, and opening the market to competitors. As such, Price Cap and competitive issues were necessarily considered along with revenue requirements and tariff/pricing issues.

- **2003 CenturyTel Rate Case/Arkansas PSC:** Mr. Brevitz led a team providing analysis and testimony on behalf of PSC staff in the CenturyTel of Northwest Arkansas rate case, in which the Company sought to treble local rates. Mr. Brevitz provided an analysis of CenturyTel of Northwest Arkansas' ("CNA") modernization programs and provision of DSL services from the perspective of basic local service ratepayers, and also addressed the local competition claims of the Company.

- **2002 Maryland Office of People's Counsel:** Maryland PSC's Case No. 8918 is to review Verizon's Price Cap regulatory plan, after Verizon had operated five or more years under it. Topics addressed included the proper productivity factor to use in the price Cap formula, and any necessary amendments to the structure of the price cap plan. Mr. Brevitz provided expert testimony on the proper formulation and terms for the price cap formula, competition, and other matters related to the extension of price cap regulation.

- **2001 Maine Office of Public Advocate–Verizon Maine 271 Review:** Review of Verizon's Section 271 filing before the Maine Public Service Commission, and Declaration filed on behalf of the Public Advocate which addresses Checklist Item #13 (Reciprocal Compensation), and Verizon's proposed performance measurement metrics and proposed Performance Assurance Plan.

2001 Vermont Department of Public Service–Verizon Vermont 271 Review: Review of Verizon's Section 271 filing assertions of compliance with the "14 Point" competitive checklist and non-discrimination obligations of the Telecommunications Act of 1996, before the Vermont Public Service Board. Mr. Brevitz filed a Declaration on behalf of the DPS which addresses

Checklist Item #13 (Reciprocal Compensation), and Verizon's proposed performance measurement metrics and proposed Performance Assurance Plan.

2001 Public Utility Research Center (PURC)/University of Florida: Presentation of two seminar modules and an interconnection case study as staff training for the Panamanian telecommunications regulatory body, ERSP. Mr. Brevitz developed course content and presentation materials for the seminar, under the auspices of PURC, on the topics of the "US Experience in Telecom Competition" and "Consumer Issues in Telecom Competition". These topics were presented by Mr. Brevitz in the seminar at Panama City, Panama on March 29-30, 2001.

- **2001-2002 Michigan Attorney General's Office–Federal District Court Litigation Support**: Mr. Brevitz supported the Attorney General's office in its defense of lawsuits by Ameritech and Verizon against the PSC and the Governor regarding recently passed state legislation. The state legislation eliminated the intrastate EUCL being charged by both companies, expanded local calling areas, and froze the application of the Price Cap Index for a period of time.

- **1999-2000 Delaware Public Service Commission Staff–Evaluation of Bell Atlantic-Delaware's Collocation Tariff Filing:** On behalf of the Staff, Mr. Brevitz reviewed BA-Delaware's Collocation tariff filing, and prefiled testimony on behalf of Delaware PSC staff. Issues addressed include non-discriminatory provisioning of collocation; collocation intervals; utilization of "best practices" for terms, conditions and pricing; and costing.

- **1999-2000 Vermont Department of Public Service–Evaluation of Carrier to Carrier Wholesale Quality of Service:** On behalf of the Vermont DPS, Mr. Brevitz was engaged in the review of quality of service standards related to Verizon's wholesale activities of provisioning Unbundled Network Elements and resold services. The work effort was conducted within a workshop of the parties, and was drawn on the similar activity for BA-NY and a number of other states including Massachusetts and Virginia. Measures, standards and benchmarks were to be determined, along with an appropriate remedy plan in the event those items are not met by the incumbent carrier. This matter was resolved in the context of Verizon's Section 271 case.

- **1999-2000 Vermont Department of Public Service–Investigation of Geographically Deaveraged Unbundled Network Prices:** On behalf of the Vermont DPS, Mr. Brevitz testified before the Vermont Public Service Board regarding the appropriateness and extent of geographic deaveraging of rates for Unbundled Network Elements (UNEs) in Vermont. In formulating these positions, it was necessary to consider FCC Orders, competitive policy implications, and related issues such as distribution of federal high cost support. The FCC had spotlighted the linkages between high cost support and geographic deaveraging determinations. Consequently the testimony also considered federal high cost support distribution implications and local rate impacts stemming from geographic deaveraging determinations to be made by the Board.

- **1999 Vermont Department of Public Service–Evaluation of Bell Atlantic Proposed Alternative Regulation Plan, Wholesale Quality of Service Standards, and Cost of Service:** Mr. Brevitz served as project manager and lead consultant in the DPS review of Bell Atlantic's proposed Price Point Plan and proposed appropriate modifications. Those modifications included moving rate reductions forward to the inception of the plan, and aligning the plan more closely to the status of competition in Vermont by allowing streamlined regulation only for truly new services, not bundles of existing services. Mr. Brevitz also supported the immediate implementation of detailed wholesale quality of service standards along with a remedies structure. Mr. Brevitz addressed the cost of service issues of reciprocal compensation and local number portability, and proposed rate design changes to effect the return of $16 million in excess revenues.

- **1998-99 Delaware Public Service Commission Geographic Deaveraging of Bell Atlantic UNE Loop Rates:** Mr. Brevitz worked for PSC staff to analyze cost and policy issues associated with geographic deaveraging of UNE loop rates. Methodology and policy to determine geographic zones was reviewed for BA-Del, and compared to all other Bell Atlantic states. BA-Del cost data was reviewed to assess closeness of fit between BA-Del's proposed population of zones with existing exchanges to the loop costs of those exchanges. After review of comments of interested parties, Mr. Brevitz prepared and submitted a report and recommendation to the PSC regarding modification of BA-Del's proposal to implement geographically deaveraged UNE loop rates. The PSC adopted the report and recommendation in its Order in the matter.

- **1998 Vermont Department of Public Service- Evaluation of Proposed Special Contracts for Toll and Centrex Services for Compliance with Imputation Requirements:** Mr. Brevitz worked for the DPS in this matter, which was an evaluation of four individual customer toll contracts, and two individual customer Centrex contracts, under the Vermont Public Service Board's price floor and imputation requirements. This evaluation included analysis of whether Bell Atlantic had appropriately followed the Board's imputation requirements; whether the imputed costs had been appropriately calculated and included all relevant costs; and, whether undue price discrimination would result from approval of Bell Atlantic's proposed prices. Mr. Brevitz analyzed the Company's filed testimony and costing information provided in support of the contract pricing; drafted staff discovery and analyzed responses of other parties in the matter; and, supported pre-filed rebuttal and surrebuttal testimony before the Board under cross examination. Hearings in this matter were held in November and December of 1998 and January 1999.

- **1998 Delaware Public Service Commission- Re-classification of Residential ISDN as "Competitive":** Mr. Brevitz worked for Delaware Public Service Commission staff in this case (Docket 98-005T), which was a filing by Bell Atlantic to move Residential ISDN ("R-ISDN") from the basic service classification to the competitive service classification, pursuant to the Telecommunications Technology Investment Act and related Commission rules to implement the Act. Bell Atlantic filed an application before the PSC stating that R-ISDN met the statutory and rule conditions for moving the service to the competitive class of services, along with market information in support of that statement. Mr. Brevitz analyzed the company's filing and the comments of other parties in the matter from an economic and public policy perspective, analyzed the Company's compliance with applicable provisions of the TTIA and Commission rules, drafted staff discovery and analyzed discovery responses of other parties, and presented testimony under cross examination before the Commission. The hearing in this matter was held July 9, 1998.

- **1997 Delaware Public Service Commission - Costing and Pricing of Residential ISDN Service:** Mr. Brevitz assisted the Delaware PSC staff in this case (Docket 96-009T) by reviewing the prefiled testimony of all parties; reviewing the cost studies supporting Bell Atlantic's proposed R-ISDN pricing; comparing those costs to Bell Atlantic's UNE rates and costs; reviewing Bell Atlantic's contribution analyses and demand forecasts for the R-ISDN service; reviewing and comparing two Bell Atlantic local usage studies (the second of which more than tripled the costs of the earlier study); providing an analytic report on the usage cost studies to PSC staff and rate counsel; assisting in the preparation and conduct of cross-examination; and assisting staff rate counsel in preparation of the brief in this matter. The hearing in this matter concluded in January 1998.

- **1997 Georgia Public Service Commission - Unbundled Network Elements Cost Study Review:** Mr. Brevitz was a lead consultant in this engagement. The GPSC opened a cost study docket to determine the cost basis for BellSouth UNE rates, following arbitration hearings involving BellSouth and several competitors. Introduced for the first time by BellSouth, and considered in the hearing was BellSouth's "TELRIC Calculator". Also considered in the hearing, as sponsored by AT&T/MCI was Hatfield Model Versions 3 and 4. Mr. Brevitz prepared and provided to GPSC staff an "Issues Matrix" which listed the issues, party positions on the issues, and a suggested staff position. Also on behalf of GPSC staff, Mr. Brevitz analyzed cost inputs and outputs pertaining to both models. No testimony was provided in this matter as GPSC staff did not testify in the hearing. Hearings on the matter concluded in September 1997.

- **1995, 1996 and 1997 Wyoming Public Service Commission - Competition Rules:** Mr. Brevitz was the Project Manager and a lead consultant for this engagement. Mr. Brevitz is actively involved in writing and implementing comprehensive competition rules in Wyoming which consider the new 1995 Telecommunications Act in Wyoming and the 1996 Federal Telecommunications Act. These rules address interconnection/unbundling, universal service, service quality, price caps/alternative regulation, privacy, resale, intraLATA dialing parity, TSLRIC/cost study methods; access charge rate design; number portability, reciprocal compensation, rights-of-way and other matters.

- **1995 and 1996 Wyoming Public Service Commission - U S WEST Pricing Plan:** Mr. Brevitz was the Project Manager and a lead consultant for this engagement. Mr. Brevitz has evaluated and filed testimony regarding U S WEST's pricing plan, competition issues, universal service and U S WEST cost study issues.

- **1996 Oklahoma Corporation Commission - Seminar on 1996 Federal Telecom Act:** Mr. Brevitz presented a seminar on the 1996 Federal Telecom Act to the Oklahoma Corporation Commission Staff.

1995 and 1996 Georgia Public Service Commission - Local Number Portability and Competition Policy: Mr. Brevitz was the Project Manager and a lead consultant for this engagement. Mr. Brevitz assisted the GPSC in implementing rules related to the new 1995 Telecommunications Act in Georgia and the 1996 Federal Telecom Act. Mr. Brevitz was primarily involved in initiating and coordinating the Number Portability Task Force and guiding the industry workshop on permanent number portability. The PSC has accepted the industry workshop recommendation. As a result, Georgia will be one of the first states to implement full number portability. Assistance was also provided on other competition issues.

- **1996 California Public Service Commission - Pricing of Unbundled Elements and Resale services:** Mr. Brevitz assisted Sprint in the pricing (second) phase of the California Commission's OANAD proceeding. Testimony was presented regarding proper pricing of unbundled network elements, given previous a PUC decision on UNE costs. The cost (first) phase involved the development of cost study principles, performance of TSLRIC cost studies of unbundled network elements by Pacific Bell and GTEC, and performance of avoided cost studies for retail services for resale.

- **1995 to 1996 Kansas Telecommunications Strategic Planning Committee - Kansas Corporation Commission:** Mr. Brevitz served as the Kansas Corporation Commission representative on this legislative committee, which was organized in mid-1994 to research and recommend any needed changes to the telecommunications statutes and state policies. The TSPC issued its final report to the Governor and the legislature in January 1996.

- **1995 Chairperson of Kansas Corporation Commission Working Groups:** Mr. Brevitz was appointed to the Cost Studies and Universal Service Working Groups for the KCC's general competition investigation, subsequent to the KCC's May 1995 Phase I competition order. He was also active in other Task Forces including Unbundling, Number Portability and Local Resale.

- **Kansas Corporation Commission - Infrastructure/Competition Report**: Produced a special report on Kansas telecommunications infrastructure/competition issues which was provided to the 1995 Kansas legislature.

- **1994 Kansas Corporation Commission - Alternative Regulation Legislation:** In 1994 the Kansas Legislature passed House Bill 3039, which extended SWBT's "TeleKansas" alternative regulation plan for two years. Mr. Brevitz provided substantial assistance in negotiating the detailed provisions for the KCC's implementation of the bill.

- **Kansas Corporation Commission - Southwestern Bell Telephone Infrastructure Analysis:** Investigated SWBT's infrastructure/modernization budget and addressed construction requirements, tariffs, rates, terms and conditions for SWBT's provision of interactive television ("ITV") to all Kansas schools at deep discount prices for the benefit of the Kansas infrastructure and schools.

Work History

Independent Telecommunications Consultant

Following a significant engagement with the Kansas Corporation Commission, extensive professional services have been provided to state public utility commissions, as indicated above under "Recent Relevant Experience".

A variety of duties and tasks have been performed for the Kansas Corporation Commission, including providing staff support for Statewide Strategic Telecommunications Planning Committee, composed of 17 members (legislators, state agency heads, private enterprise); assisting in KCC implementation of House Bill 3039 ("TeleKansas II", extension of alternative regulatory plan for Southwestern Bell Telephone); and providing analysis and testimony for communications general investigations into competition in the local exchange and other markets. Those general investigations included General Competition, Competitive Access Providers, Network Modernization, Universal Service, Quality of Service, and Access Charges.

Kansas Consolidated Professional Resources - Director of Regulatory Affairs

Duties included monitoring of and participating in state regulatory affairs on behalf of twenty independent local exchange companies in Kansas that compose the partnership of KCPR. Active participation in statewide industry committees in the areas of access charges, optional calling plans/EAS, educational interactive video, dual party relay systems and private line/special access merger.

Kansas Corporation Commission - Chief of Telecommunications

Duties included supervising the formulation of staff testimony and policy recommendations on matters such as long distance competition, access charges, telephone company rate cases, and deregulation of CPE and Inside Wiring; analyzing Federal Communications Commission and Divestiture court decisions; supervising and performing tariff analysis; and testifying before the Commission as necessary. SWBT's $120 million "Divestiture rate case" was completed in this time period, as were several other large rate cases. Active member of the National Association of Regulatory Utility Commissioners (NARUC) Staff Committee on Communications.

Arizona Corporation Commission - Chief Rate Analyst - Telecommunications

Duties included supervision of staff and formulation of policy recommendations on telecommunications cases, along with production of analyses and testimony as required.

Kansas Corporation Commission - Economist - Research and Energy Analysis Division

Duties included research, analysis and production of casework and testimony regarding gas/electric and telecommunications matters. Matters addressed included revision of jurisdictional separations, deregulation of CPE and inside wire, Wolf Creek Nuclear Generating Plant Task Force, and divestiture of the Bell Operating Companies from AT&T.

Education

Michigan State University - Graduate School of Business
East Lansing, Michigan
Master's Degree in Business Administration-Finance.

Michigan State University/James Madison College
East Lansing, Michigan
Bachelor of Arts Degree in Justice, Morality and Constitutional Democracy.

EXHIBIT DB-2

Testimony of David Brevitz
Case Number 2007-00455
Exhibit DB-2

	Calendar Year	2008 H2	2009	2010	2011	2012	2013	2014	2015
<u>Scenario</u>									
Smelters Leave	Effective Rate ($/ MWH)	35.82	35.71	35.69	37.01	43.62	47.83	48.50	49.69
Base Case	Effective Rate ($/ MWH)	35.82	35.71	35.69	37.75	36.85	42.90	44.96	46.57
Increase/(Decrease)		-	-	-	(0.74)	6.76	4.93	3.55	3.12
% Increase/(Decrease)		0%	0%	0%	-2%	18%	11%	8%	7%

	Calendar Year	2016	2017	2018	2019	2020	2021	2022	2023
<u>Scenario</u>									
Smelters Leave	Effective Rate ($/ MWH)	50.08	59.71	59.87	60.39	60.71	60.97	61.42	61.96
Base Case	Effective Rate ($/ MWH)	47.43	50.63	51.18	51.53	52.26	52.71	53.34	53.61
Increase/(Decrease)		2.65	9.08	8.69	8.86	8.46	8.25	8.08	8.34
% Increase/(Decrease)		6%	18%	17%	17%	16%	16%	15%	16%

Source: Page 3, line 46 of the Financial Model, for each referenced scenario

EXHIBIT DB-3

Testimony of David Brevitz
Case Number 2007-00455
Exhibit DB-3

Scenario:	"Base Case"				"Smelters Leave"			
	Margin	TIER	Surcharges	Total	Margin	TIER	Surcharges	Total
Present Value ($mil)	$18.39	$144.46	$164.29	$327.15	$7.14	$25.53	$53.61	$86.28
Discount Rate	5.40%	5.40%	5.40%		5.40%	5.40%	5.40%	26.37%
Year								
2008	1.2	0	9.3		1.2	0	9.3	
2009	1.8	0	10.3		1.8	0	10.3	
2010	1.8	0	13.9		1.8	0	13.9	
2011	1.8	13.2	13.9		1.8	13.2	13.9	
2012	1.8	19.3	16.1		1.8	19.3	16.1	
2013	1.8	17.5	16.1		0	0	0	
2014	1.8	16.5	16.1		0	0	0	
2015	1.8	23.1	16.1		0	0	0	
2016	1.8	21.1	16.1		0	0	0	
2017	1.8	22.9	18.9		0	0	0	
2018	1.8	1.1	18.9		0	0	0	
2019	1.8	23.1	18.9		0	0	0	
2020	1.8	15.8	19		0	0	0	
2021	1.8	25.2	18.9		0	0	0	
2022	1.8	18.3	18.9		0	0	0	
2023	1.8	27	18.9		0	0	0	

Source: BREC Response to OAG No. 67

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATIONS OF BIG RIVERS ELECTRIC CORPORATION FOR: (I) APPROVAL OF WHOLESALE TARIFF ADDITIONS FOR BIG RIVERS ELECTRIC CORPORATIONS, (II) APPROVAL OF TRANSACTIONS, (III) APPROVAL TO ISSUE EVIDENCES OF INDEBTEDNESS, AND (IV) APPROVAL OF AMENDMENTS TO CONTRACTS; AND OF E.ON U.S., LLC, WESTERN KENTUCKY ENERGY CORP. AND LG&E ENERGY MARKETING, INC. FOR APPROVAL OF TRANSACTIONS	) CASE NO. 2007-00455

AFFIDAVIT OF DAVID BREVITZ

State of Kansas)
)
)

David Brevitz, being first duly sworn, states the following: The prepared Pre-Filed Direct Testimony, and the exhibits attached thereto constitute the direct testimony of Affiant in the above-styled case. Affiant states that he would give the answers set forth in the Pre-Filed Direct Testimony if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, his statements made are true and correct. Further affiant saith not.

David Brevitz
David Brevitz

SUBSCRIBED AND SWORN to before me this 2 day of April, 2007.

Brandy Atk
NOTARY PUBLIC

My Commission Expires: 11-15-11

NOTARY PUBLIC - State of Kansas
BRANDY ATKINS
My Appt. Expires 11-15-11

RECEIVED

NOV 21 2008

PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY
OFFICE OF THE ATTORNEY GENERAL

JACK CONWAY
ATTORNEY GENERAL

1024 CAPITAL CENTER DRIVE
SUITE 200
FRANKFORT KENTUCKY 40601

November 21, 2008

Ms. Stephanie Stumbo
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, KY 40601

Re: Big Rivers Electric Unwind Hearing Date
Case No. 2007-00455

Dear Ms. Stumbo:

Please find attached hereto the supplemental direct testimony of David Brevitz on behalf of the Attorney General. This testimony was also served upon all parties to the matter as indicated in the certificate of service.

I thank you in advance for your attention to this matter.

Sincerely,

Dennis G. Howard, II
Acting Director
Office of Rate Intervention

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2007-00455
SUPPLEMENTAL DIRECT TESTIMONY OF
DAVID BREVITZ

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is David Brevitz. My business address is 3623 SW Woodvalley Terrace, Topeka, Kansas.

Q. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am an independent consultant serving state regulatory commissions, Attorney General's Offices, and consumer organizations. I am testifying on behalf of the Attorney General of Kentucky.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS MATTER?

A. Yes, I filed Direct Testimony on April 3, 2008. That filing of testimony was immediately preceded by the First Amendment and Supplement to the Application by Joint Applicants. However, as the Commission is aware the scheduled hearing was postponed due to subsequent events. By the time the presently rescheduled hearing in this matter occurs, it will have been pending before the Commission for almost a year as it has been amended and supplemented a number of times.

Q. WHAT WAS THE CAUSE OF THAT POSTPONEMENT, AND WHAT EVENTS HAVE OCCURRED SUBSEQUENT TO THAT POSTPONEMENT?

A. The general cause of the postponement was the developing negative conditions in the financial markets which interfered with Big Rivers Electric Company ("BREC")'s original plans to issue public debt and later became more severe with BREC's loss of the required credit enhancement (of its leases) of AMBAC due to AMBAC's ratings downgrade. As a result, the Joint Applicants have made Second and Third Amendments and supplements to the original filing, and have filed or provided several other pleadings or documents since the time of the originally scheduled hearing. The information provided includes subsequent updated runs of the Unwind Financial Model in June 2008 and October 2008.

Q. *HAVE YOU REVIEWED AND CONSIDERED THE INFORMATION WHICH HAS BEEN FILED OR PROVIDED BY JOINT APPLICANTS AND OTHER PARTIES SUBSEQUENT TO THE FILING OF YOUR DIRECT TESTIMONY?*

A. Yes. I have reviewed each filing of information in this matter, including additional discovery responses, and have participated via teleconference in periodic informal conference meetings among the parties.

Q. WHAT WAS YOUR RECOMMENDATION IN YOUR ORIGINAL DIRECT TESTIMONY?

A. Due to the fact there were a number of items unknown at that time, I made "a provisional recommendation that the Commission approve the transactions, but with limited enthusiasm, and with certain conditions and understandings".[1] The conditions were designed to address concerns with the proposed transaction and its projected impacts based on the facts and circumstances as they existed at that time. I was explicit that "this testimony must be considered as preliminary until the record has been supplemented by the Joint Applicants to include and address these crucial areas, which are demonstrably and materially incomplete."[2] Those four "crucial areas" were lack of complete information and documentation on planned financing, lack of credit ratings, lack of required consents including the City of Henderson, and lack of a completed due diligence

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[1] Direct Testimony of David Brevitz, page 50, lines 14-16

[2] Id., page 5, lines 21-23

report.[3] I also observed that "the Commission could reasonably hold this proceeding in abeyance until these matters have been accomplished".[4]

Q. HAVE THESE FOUR AREAS BEEN COMPLETED AND ADDRESSED IN THE INTERVENING SIX MONTHS?

A. No. There is no real finality on any of these issues.

- The circumstances regarding financing have changed from one unknown to another. Previously, public capital markets were planned to be used for debt proceeds in concert with closing the proposed transaction, but specifics were lacking. Now, BREC proposes to access public capital markets three times, in 2011, 2015 and 2018.[5] The borrowing in 2015 is referenced as being for $200 million. Obviously, the specifics regarding these debt offerings are both distant and unknown at this time.
- BREC has not yet sought credit ratings from credit ratings entities, and plans to do so after the Commission's action on this matter.
- The required consent of the City of Henderson still has not been obtained, and as discussed below, the same impasse as before appears to exist on two material issues.
- There is a lack of finality to "due diligence", as there is no due diligence report, and due diligence will evidently occur up to the point of closing the proposed transaction. This implies that there could be future items which arise in due diligence review with a cost impact.

Q. GIVEN THE EVENTS IN THIS MATTER (OR LACK THEREOF) SUBSEQUENT TO THE FILING OF YOUR DIRECT TESTIMONY, IS YOUR RECOMMENDATION TO THE COMMISSION THE SAME?

A. No. Under the current circumstances and the proposed transaction as amended, I am not able to recommend that the Commission approve the proposed transaction at this time.

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[3] Id., lines 1-20.
[4] Id., page 47, line 29
[5] Supplemental Direct Testimony of Robert S. Mudge, Exhibit 98, Page 7, Line 12-17

The concerns expressed in my previous Direct Testimony should be read together and harmonized with the concerns expressed in this Supplemental Direct Testimony.

Q. WHY ARE YOU NOT ABLE TO RECOMMEND THAT THE COMMISSION APPROVE THE PROPOSED TRANSACTION UNDER ITS PRESENT STRUCTURE AND CIRCUMSTANCES?

A. The effect of subsequent events on the proposed transaction in concert with the lack of finality on the issues noted above yield three primary reasons why I am not able to recommend approval of the proposed transaction. They are:

1. Substantial further rate increases for residential customers are indicated over and above the rate increases which were projected in the Unwind Financial Model which was the subject of my Direct Testimony; and,
2. The required consent from the City of Henderson has not yet been obtained by the Joint Applicants, and the cost impact of obtaining such consent is unknown at this time but clearly more than is incorporated in the current (October 2008) Unwind Financial Model.
3. Despite numerous iterations of the Model and the passage of approximately six more months, the Application is still incomplete at this time including the lack of resolution on the City of Henderson's required consent.

<u>Projected Further Rate Increases</u>

Q. PLEASE SUMMARIZE THE EXTENT OF INDICATED FURTHER RATE INCREASES FOR RESIDENTIAL (RURAL) RATES.

A. Projected rates from the different runs of the Unwind Financial Model—February 2008 vs. October 2008—can be compared to yield percentage rate increases as follows:

	Additional Increase over Feb Model					
	2009	2010	2011	2012	2013	2014
Rural Rates	3.13%	8.75%	11.79%	17.46%	8.49%	10.79%

This is the projected increase to rural rates which has occurred due to changed circumstances and events since the Unwind Financial Model run addressed by my original Direct Testimony.

Q. PLEASE SUMMARIZE THE EXTENT OF INDICATED RATE INCREASES FOR RESIDENTIAL (RURAL) RATES FROM THE PROPOSED UNWIND TRANSACTION VERSUS CURRENT RATES RESULTING FROM THE LEASE AGREEMENT.

A. The projected increase in the October 2008 Unwind Financial Model, over the effective 2008 rate is:

				Increase vs. Current Rates			
	2008	2009	2010	2011	2012	2013	2014
Rural Rates							
Increase $/MWH	35.33	1.89	3.86	5.67	7.71	10.59	13.47
% Increase Over Current		5.34%	10.90%	16.01%	21.77%	29.92%	38.03%

This shows that significant increases in rates are projected to occur year after year, without consideration of further unforeseeable circumstances, and also without resolution of the City of Henderson consent which when quantified in the model could translate to even more increases.

Q. WHAT ARE THE FACTORS OR ELEMENTS THAT CONTRIBUTE TO THE INCREASED RATES PROJECTED IN THE CURRENT MODEL VERSUS THE FEBRUARY 2008 VERSION, UPON WHICH YOUR PREVIOUS TESTIMONY WAS BASED?

A. Projected increased operating expenses, increased interest costs, and increased capital expenditures appear to be the primary drivers of the increased rates projected in the Unwind Financial Model, when comparing February 2008 to the most current version of the model—October 2008. Projected increased operating costs appear to be predominant among those items. These increases are displayed below:

	Calendar Year	2009	2010	2011	2012	2013	Total
Oct. 08	Total Disbursements	451.56	498.30	530.34	565.80	599.33	
Feb. 08	Total Disbursements	393.33	407.73	436.07	438.75	460.48	
	Difference	58.23	90.57	94.27	127.05	138.85	508.98
	%	14.80%	22.21%	21.62%	28.96%	30.15%	
Oct. 08	Total Expenses	564.13	581.69	619.81	658.67	689.33	
Feb. 08	Total Expenses	473.33	486.42	519.12	524.36	538.24	
	Difference	90.79	95.27	100.69	134.31	151.09	572.15
	%	19.18%	19.59%	19.40%	25.61%	28.07%	
Oct. 08	Total Capital Expenditures	93.47	51.30	63.67	42.23	50.11	
Feb. 08	Total Capital Expenditures	76.01	58.58	56.26	53.85	35.54	
	Difference	17.46	-7.29	7.41	-11.62	14.56	20.52
	%	22.97%	-12.44%	13.17%	-21.58%	40.97%	

Q. WHY DOES THE INCREASING EXTENT OF PROJECTED RESIDENTIAL RATE INCREASES CONCERN YOU?

A. There are several reasons why growing projected residential rate increases in the Unwind Financial Model are of sufficient concern that I cannot recommend that the Commission approve the Unwind Transaction as proposed.

1. BREC is a relatively small organization that is not diversified on either a geographic or product basis. But it proposes to resume full exposure (outside the current lease agreement) to future capital expenditure and expense requirements under the proposed transaction. As stated by BREC before a meeting of the Board of Commissioners of the City of Henderson:

> This is a very complex transaction. Yes, it involves a lot of money, but it involves tremendous risks coming back to Big Rivers to operate these power plants and provide the volume of energy that goes to not only Alcan, but to Century and that is a load that no other electric generation

and transmission cooperative, nor utility that I am aware of, has to support in this country, that is two large smelters and a 98% load factor.[6]

2. Due to this smaller size and undiversified position, BREC is exposed to unforeseen negative consequences from future events which could exert substantial pressures to increase expenses and/or capital expenditures. This has been demonstrated by the past six months and the change in projected rates over that time period.
3. Estimated capital expenditures and expenses in the Unwind Financial Model are subject to some potential for error due to the fact that BREC has not operated the plants for ten years. As time has elapsed, BREC appears to have found more required costs which have been included in the Unwind Financial Model and contribute to projected rate increases.
4. Required early termination of the leases has diminished BREC's cash from that which was projected to be available in February 2008. All other things equal, this contributes to the need to increase rates to generate cash. It does not appear that BREC has a realistic ability to obtain additional cash financing from the member cooperatives. Therefore, any additional cash requirements must be obtained externally—from additional debt borrowings which increase cash debt service requirements, and ultimately from increased rates. Within the boundaries of materiality, any additional cash requirements of BREC must come from increased rates absent opportunities for increased revenues from other sources or cost cutting.
5. The issues regarding obtaining the required consent for the proposed transaction from the City of Henderson are unresolved and cause significant uncertainty regarding additional costs associated with accomplishing the proposed transaction.

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[6] BREC Response to OAG Supplemental No. 33, Verbatim transcript of Special Called Commission Meeting, June 27, 2008, at page 3.

6. Recommending approval of the proposed transaction with the significantly increased projected rates implies pre-approval of planned or "required" later rate increases.

<u>Lack of Required Consent from the City of Henderson</u>

Q. IS IT CLEAR THAT THE REQUIRED CONSENT TO THE PROPOSED TRANSACTION FROM THE CITY OF HENDERSON IS IMMINENT?

A. No. It does not appear that such consent is imminent. Copies of communications between Joint Applicants and the City of Henderson and/or HMP&L were sought via OAG Supplemental No. 10 to E.ON, and OAG Supplemental No. 33 to BREC, and requested copies were provided. It appears that some level of communication among the entities began in the later part of 2005, and continued from time to time, and somewhat intermittently at times to the current point. The documents I have reviewed suggest to me that a number of issues may have been resolved over time, but two core issues remain and there does not appear to be substantive progress on those issues—in fact, matters currently appear to be at an impasse.

Q. DID YOU HAVE THESE DOCUMENTS AND CORRESPONDENCE AVAILABLE AT THE TIME OF YOUR DIRECT TESTIMONY?

A. No. None of the correspondence up to that point in time was available.

Q. WHAT ARE THE TWO ISSUES WHICH CURRENTLY REMAIN?

A. The August 29, 2008 Status Report identifies two dispute areas impeding the City of Henderson's consent to the early termination of the Station Two Agreement in the BREC/E.ON existing transaction for the Unwind Transaction to be consummated. Henderson continues to assert as follows:

1. "Henderson retail customers are subsidizing the profits of WKEC currently, and Big Rivers in the future, because while Henderson must pay for its share of Station II capacity, Henderson only receives a margin of $1.50/MHW for excess energy utilized by WKEC and Big Rivers; and,"

2. "there are a number of maintenance and repair claims with Station II resulting from WKEC's operation of the Station Two facility."

By its letter dated September 3, 2008, Henderson appears to agree on the identity of the remaining issues, as follows: "discussions [between the Chairman of the Henderson Utility Commission and the Chairman of Big Rivers] failed to resolve the two key issues: Excess Energy sales and Station Two maintenance and repair expenses reflected in the independent engineering reports."

Q. DID THESE TWO ISSUES ALSO EXIST IN MARCH-APRIL 2008 WHEN THE PROCEDURAL SCHEDULE BECAME PROBLEMATIC AND ULTIMATELY THE HEARING WAS POSTPONED?

A. Yes. My review of the correspondence documents suggests that these issues clearly existed at that time and prior to it.

Q. WAS THE SIX MONTH PERIOD BETWEEN THEN AND NOW USED AND USEFUL TO RESOLVE THESE ISSUES?

A. No. At the end of March 2008, BREC informed the City of Henderson that it had "nothing further to offer." Discussions appear to have been non-productive after that point, punctuated mainly by a specially called Henderson City Commission meeting on June 27, 2008, and three meetings involving the Chairmen of BREC and HMP&L in the period August 1, 2008 to September 2, 2008. The impasse or stalemate between the parties was not subject to any material change from these later meetings that I can see. If anything, positions appear to have hardened.

Q. WHAT DO THE DOCUMENTS BETWEEN BREC, E.ON AND HMP&L ILLUSTRATE REGARDING THE CURRENT STALEMATE OR IMPASSE?

A. There are a number of documents provided in response to OAG Supplemental No. 33 (to BREC) and OAG Supplemental No. 10 (to E.ON). One is a piece of mail from HMP&L to its customers regarding the proposed transaction in March 2008 stating its view of the issues.[7] All other things equal, the mailing would tend to harden views regarding consent to the proposed transaction. Discussions and exchange of correspondence between the entities were occurring at that time, including a letter from BREC to HMP&L, which expressed "disappointment" with the HMP&L response to the latest BREC proposal, and indicated "Big Rivers has nothing further to offer to HMP&L".[8] Correspondence also indicates that the Chairmen of BREC and HMP&L met on September 2, 2008 on the open issues.[9] One concern evident on the part of HMP&L is that Big Rivers would experience financial problems after the Unwind and potentially file for bankruptcy. HMP&L proposed contract amendments to deal with this potential circumstance. BREC was not able or willing to accept HMP&L's proposal "because it shifts costs to our Members and substantially changes the Station Two agreement" beyond which it would "be unacceptable to [BREC] creditors whose approvals would also be required".[10] It does not appear to me that agreement between the Joint Applicants and the City of Henderson on remaining issues pertaining to required consent for the proposed transaction is imminent.

Q. ARE YOU ABLE TO ASSESS THE FINANCIAL IMPACT TO CONSUMERS IN THE ABSENCE OF THE NECESSARY AGREEMENT BY THE CITY OF HENDERSON TO THE PROPOSED TRANSACTION?

A. No. The financial impact on consumers is not yet known since there is no agreement or understanding regarding the financial circumstances to obtain the City of Henderson's consent. It appears to me that the further any resolution goes toward the City's position, the more material an impact would exist for BREC consumers. BREC has only incorporated the financial impact of its last proposal into the Unwind Financial Model (October 2008) currently before the Commission.

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[7] BREC Response to OAG Supplemental No. 33.
[8] Id., Letter from Michael Core to Gary Quick, March 28, 2008.
[9] BREC Response to OAG Supplemental No. 33 BREC Supplemental Response to OAG No. 107 indicates that Dr. Smith and Mr Denton met twice, once on August 1, 2008, then again on September 2, 2008.
[10] BREC Response to OAG Supplemental No 33, Letter from Mark Bailey to Gary Quick, September 24, 2008.

Q. ARE YOU EXPRESSING ANY VIEW REGARDING THE UNDERLYING FACTS OF THE IMPASSE BETWEEN BREC AND HMP&L?

A. No, nothing in the foregoing should be construed as expressing any opinion regarding the relative merits of the facts on this issue between BREC and HMP&L. The relevant point is that the necessary consent to accomplish the proposed transaction has not been obtained, and obtaining such consent could require further material cost which is not included in the Unwind Financial Model or its projected rates.

Investment Grade Credit Rating

Q. DID YOU ADDRESS THE SUBJECT OF CREDIT RATINGS IN YOUR PREVIOUS TESTIMONY?

A. Yes, see pages 34-37 of that testimony.

Q. DO YOU HAVE ANYTHING TO ADD TO THAT DISCUSSION?

A. Yes. In addition I note that the Commission has as much to do with the investment grade credit rating as the innate nature of the proposed transaction for BREC. An investment grade credit rating has some circularity with Commission approval. Credit rating entities will rely on the Commission's approval of the proposed transaction as implicit commitment to increase rates to the extent necessary to maintain BREC's financial viability and ensure timely debt service payments.

Conditions

Q. YOUR DIRECT TESTIMONY CONTAINED RECOMMENDED CONDITIONS AT PAGES 50-52. HOW DOES THE FACT THAT YOU CAN NO LONGER RECOMMEND APPROVAL OF THE PROPOSED TRANSACTION IMPACT THESE RECOMMENDED CONDITIONS?

A. If the Commission decides to approve the proposed transaction, the direction of the previously proposed conditions is still valid and the Commission should consider them.

In its decision, the Commission should address each proposed condition and incorporate each one as updated and modified by subsequent events. In particular, the first proposed condition would require additional contribution to economic reserve funds to mitigate the residential increased rates projected by the October 2008 modeling subsequent to the February 2008 modeling upon which my Direct Testimony was based. The third proposed condition could be addressed in part by agreement between BREC, the City of Henderson, and E.ON regarding the condition of generating facilities and sites.

Q. ARE YOU NOT CONCERNED ABOUT THE POTENTIAL LOSS OF JOBS IF THIS TRANSACTION IS NOT APPROVED AND ULTIMATELY CONSUMMATED?

A. I am very much concerned about this issue and the Attorney General has advised me that he is as well. However, even if the Commission approves the application and the proposed transaction occurs, there is no guarantee that the smelters will continue their operations in Kentucky. In fact, the smelters have negotiated terms which would allow them to terminate their contracts as soon as 2011[11] and would allow the closing of a pot-line depending on the market for a period of up to 12 months and then re-selling the electricity that would have otherwise been used.[12] Obviously the possibility of a loss of jobs exists regardless of the Commission's actions in this matter. Accordingly, because the smelters have this agreement in place, it appears self-evident that the smelters anticipate the possibility, if not the likelihood that there will be a loss of jobs.

Q. DOES THIS CONCLUDE YOUR SUPPLEMENTAL TESTIMONY?

A. Yes.

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[11] Direct testimony of C William Blackburn, Exhibit 10, Page 65-66

[12] Direct testimony of C. William Blackburn, Exhibit 10, Page 45-46. Under this circumstance, current projections indicate the smelter would earn approximately $14 million. BREC Response to OAG Supplemental No. 34. This figure will be different depending on market conditions at the time.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATIONS OF BIG RIVERS ELECTRIC CORPORATION FOR: (I) APPROVAL OF WHOLESALE TARIFF ADDITIONS FOR BIG RIVERS ELECTRIC CORPORATIONS, (II) APPROVAL OF TRANSACTIONS, (III) APPROVAL TO ISSUE EVIDENCES OF INDEBTEDNESS, AND (IV) APPROVAL OF AMENDMENTS TO CONTRACTS; AND OF E.ON U.S., LLC, WESTERN KENTUCKY ENERGY CORP. AND LG&E ENERGY MARKETING, INC. FOR APPROVAL OF TRANSACTIONS	) CASE NO. 2007-00455

AFFIDAVIT OF DAVID BREVITZ

State of Kansas)
)
County of)

David Brevitz, being first duly sworn, states the following: The prepared Pre-Filed Supplemental Direct Testimony, and the exhibits attached thereto constitute the direct testimony of Affiant in the above-styled case. Affiant states that he would give the answers set forth in the Pre-Filed Supplemental Direct Testimony if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, his statements made are true and correct. Further affiant saith not.

David Brevitz
David Brevitz

SUBSCRIBED AND SWORN to before me this 21st day of Nov, 2008.

Kathy A. Lacy
NOTARY PUBLIC

My Commission Expires: 4/27/11

KATHY A. LACY
Notary Public - State of Kansas
My Appt Exp 4/27/11

CERTIFICATE OF SERVICE AND NOTICE OF FILING

I hereby give notice that this the 21st day of November, 2008, I have filed the original and ten copies of the foregoing with the Kentucky Public Service Commission at 211 Sower Boulevard, Frankfort, Kentucky, 40601 and certify that this same day I have served the parties by mailing a true copy of same, postage prepaid, to those listed below.

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Exhibit DB-3

THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

Before Commissioners: Michael Lennen, Chairman
Margalee Wright
Keith R. Henley

In the Matter of the Application of Sunflower Electric Cooperative, Inc., for approval of the State Corporation Commission to make certain changes in its charges for sale of electricity to its member cooperatives.	) DOCKET NO.) 143,069-U) 84-SNFE-369-R

ORDER

Now, this matter comes on for consideration and determination by the State Corporation Commission of the State of Kansas upon the application of Sunflower Electric Cooperative, Inc., (Sunflower) for approval of the Commission to make certain changes in it's charges for sale of electricity to it's member cooperatives.

I. INTRODUCTION

On September 5, 1984, Sunflower filed an application requesting permission to increase its charges for sale of electricity to its member cooperatives to produce an increase in annual gross revenue of $17,070,175.00 on a permanent basis. The requested increase reflects an additional 13% of the Holcomb Unit in rate base bringing the total of the Holcomb Unit in rate base to 60%; inclusion of the gas operations to include the gas gathering system but excluding the nitrogen rejection plant certain transmission lines and other facilities which were completed and in commercial service on December 1982; and demand charges related to purchase power contracts with Kansas Power and Light Company and Centel in the amount of $7,472,100.

On November 2, 1984, the Commission entered an Order setting a hearing on the Application for January 15, 1985 in Topeka, Kansas. The hearing on this matter commenced as scheduled on January 15, 1985, at 9:00 a.m. in Hearing Room B, 4th Floor, State Office Building, Topeka, Kansas. The hearing was concluded on January 18, 1985. The record for the technical hearing includes thirty-two exhibits and 1,166 pages of testimony taken from twenty witnesses. In addition, a total of sixty-seven witnesses testified before the Commission at public hearings held in Norton, Colby, Scott City, Ulysses and Garden City. The testimony given in these public hearings was crucial in the determination of the Commission.

Appearances of Counsel were as follows:

L. Earl Watkins, Jr., Great Bend, Kansas and Jack Glaves, Wichita, Kansas, for the Applicant Sunflower Electric Cooperative, Inc.;

Milo M. Unruh, Sr. and Milo M. Unruh, Jr., Wichita, Kansas, for Intervenor IBP, Inc.

W. Robert Alderson, Topeka, Kansas, and Gerard E. Little, Garden City, Kansas, for Intervenor the City of Garden City;

Michael K. Ramsey, Garden City, Kansas, for Intervenor Pioneer Electric Cooperative;

Keen K. Brantley, Scott City, Kansas, for Intervenor Wheatland Electic Cooperative;

E. Jay Deines, Wakeeney, Kansas, for Intervenor Western Cooperative Electric Association, Inc.;

James M. Milliken, St. Francis, Kansas, for Intervenor Northwest Kansas Electric Cooperative;

William J. Ryan, Norton, Kansas, for Intervenor Norton-Decatur Cooperative Electric Company, Inc.;

John D. Gatz, Colby, Kansas for Intervenor Great Plains Electric Cooperative;

Martin R. Ahrens and Kirby A. Vernon, Topeka, Kansas, for the Commission Staff and the public generally.

The following witnesses testified at the technical hearings:

Witnesses for the Applicant were Steven W. Thompson, Assistant General Manager; Sidney J. Severson, Director of Finance and Accounting; Robert L. Anderson, Director of

Electrical Operations; Blake McGuire, Director of Administration, all of Sunflower Electric Cooperative, Inc., Hays, Kansas;

Scott Keith and John C. Dunn of Drees Dunn and Company, Overland Park, Kansas;

Alfred J. Gerstner, Manager, Great Plains Electric Cooperative, Colby, Kansas;

Maurice L. O'Brien, Manager, Lane-Scott Electric Cooperative, Inc., Dighton, Kansas;

Carroll Ginther, Manager, Northwest Kansas Electric Cooperative Association, Inc., Bird City, Kansas;

Philip A. Lesh, Manager, Norton-Decatur Cooperative Electric Company, Inc., Norton, Kansas;

Charles B. Holt, Manager, Pioneer Electric Cooperative, Inc., Ulysses, Kansas;

Lewis E. Mitchell, Manager, Wheatland Electric Cooperative, Inc., Scott City, Kansas.

The Commission Staff presented testimony by:

James R. Armstrong, Chief Utility Regulatory Auditor; Ronald Ford, Rate Design and Depreciation Analyst; Michael T. York, Economist II; Morgan Robert Pauley, Chief Economist, Manager of Research; and Hossein A. Novin, Construction Inspector; all of whom are on the Staff of the Kansas Corporation Commission, Topeka, Kansas.

The following witnesses testified for Intervenor City of Garden City: Dean P. Wiley, Manager, Garden City, Kansas; Charles Eugene Chick, Stone and Webster Management Consultants, Denver, Colorado.

The following witness testified on behalf of IBP:

Ronald B. McElvain, Corporate Energy Manager, IBP, Inc., Dakota City, Nebraska.

The following rebuttal witnesses testified on behalf of Applicant Sunflower Electric Cooperative: Sidney J. Severson and Scott Keith.

II. FINDINGS OF FACT AND CONCLUSIONS OF LAW

The Commission, being fully advised in the premises and having given due consideration the Application and all the evidence relating thereto, finds and concludes as follows:

III. JURISDICTION

1. Applicant, a corporatation organized and existing under the laws of the State of Kansas, and pursuant to the provisions of K.S.A. 66-101 et seq. is authorized to engage in the business of a public utility in accordance with its certificate of convenience and necessity and is subject to the jurisidiction of this Commission. Notice of the application and the hearings thereon was duly given to each of the eight (8) member cooperatives, the City of Garden City and IBP, Inc. Further, notice of hearing was published in the Country Living Magazine. The Commission finds that it has jurisdiction over the subject matter and the parties.

IV. HISTORY

2. This rate case was filed by Sunflower in order to continue to place in rate base the recently completed coal-fired plant known as Holcomb Unit No. 1.(Holcomb Unit) The Holcomb Unit was the subject of the first and, at this point, the only application for a siting permit for an electric generation facility pursuant to K.S.A. 66-1,159. Subsequent to hearings in Docket No. 114,010-U, an order was issued on October 23, 1978, which authorized the construction of the Holcomb Unit. The Commission found, at that time, studies showing growth and power requirements of 8% per year for a reasonable period. The Commission further found that the Holcomb Unit appeared to be "reasonable for the Applicant's needs in 1983". The estimated cost of the unit, according to the "Unit Sizing Study" by Burns and McDonnell, Consulting Engineers, was $278,000,000.

On October 15, 1980, the Commission issued an order in Docket No. 124,740-U, granting Sunflower authority to issue mortgage notes for the financing of the Holcomb Unit and related transmission facilities. The borrowing related to the Holcomb Unit was stated as $459,884,000, including interest during construction, and was approved at that level by the Rural Electrification Administration (REA). At that time, the cost of the Holcomb Unit was estimated by Sunflower to be $380,000,000 direct cost plus $55,000,000 interest during construction for a total of $435,000,000.

3. In Docket No. 123,667-U, a complaint case requesting that Sunflower's permit for the Holcomb Unit be suspended and the matter investigated, the Commission issued an order on October 15, 1980, dismissing the complaint. Further, the Commission monitored the construction of the Holcomb Unit in Docket No. 125,320-U, a general investigation, which was initiated by order dated October 15, 1980. Subsequently, the Commission issued an order on November 5, 1982, in Docket No. 125,320-U recognizing a revised line item estimate which added $6,508,900 to the total Holcomb Unit estimate. The additional costs associated with accelerated construction were authorized in order that completion of the Holcomb Unit would occur within the timeframe set by federal legislation to qualify portions of the Holcomb Unit for the substantial benefits of Safe Harbor Leasing.

4. The Commission notes that at the time of the initial estimate there was little expectation that stringent federal legislation would require extensive pollution control equipment which added substantially to the cost of the Holcomb Unit. Also, in 1978 few anticipated that interest rates would climb to the level of those experienced by Sunflower. In fact, the $279,417,965 construction cost of the Holcomb Unit which reflects elimination of coal and limestone inventories, a reclassification of the cost of land and the costs associated with accelerated

construction for purposes of Safe Harbor Lease qualification is more than $10,000,000 less than the $289,542,000 cost estimate made in May of 1980. That same May 1980 estimate anticipated a $55,000,000 AFUDC expense. The Commission's order in Docket No. 137,068-U reflected a total of $66,763,000 which was adjusted by staff to $91,173,000 in this case. As reflected in Mr. Armstrong's Exhibit 15, Section JA-7, Schedule CC, page 3, the total estimate in May of 1980 was $435,000,000 compared to an actual test year end April 30, 1984, of $462,067,868. The Commission notes that the actual figure as presented in Mr. Armstrong's exhibit does not reflect any additional deferral cost associated with the on-going Holcomb Unit phase in plan. Nor does it include any savings derived from the Safe Harbor Leasing transactions for which Sunflower did qualify. The total Safe Harbor proceeds received from the three transactions was $54,265,493. Safe Harbor Lease 1 amounted to $2,543,907; Safe Harbor Lease 2 amounted to $3,241,698; and Safe Harbor Lease 3 amounted to $48,479,888.

V. DEFERRAL PLAN

5. Sunflower based its application on the placement of 60% of the Holcomb Unit in rate base. This is consistent with the terms of the Deferral Plan filed with REA in which Sunflower contemplated 50% of Holcomb in rate base the first year and an additional 10% of Holcomb each succeeding year until the entire plant was in rate base after the sixth year.

6. The Commission affirms its position to evaluate each rate case on its own merits and allow such further portion of the Holcomb Unit to be placed into rate base as can be justified on the basis of usage, economics, rate impact, price elasticity, off system sales, peak requirements, carrying costs and load growth.

VI. CAPACITY REQUIREMENTS

7. Sunflower recognizes the fact that capacity exists above system demand and reserve requirements. For purposes of

this application, Sunflower requested that 60% of Holcomb Unit be placed in rate base. (Thompson Vol. I, TR. 75)

8. To determine the appropriate percentage of the Holcomb Unit to include in rate base, the Commission evaluated Sunflower's total generating capacity, firm purchases and sales, reserve requirements, system demand and performance criteria.

A. Generation Capacity

9. Mr. Thompson agreed on cross-examination that the net generating capability of the Sunflower system was 515 megawatts as reported to the Southwest Power Pool and reflected in Exhibit No. 4 (Thompson Vol. I, TR. 73). Mr. Thompson characterized the individual generating units on the Sunflower system as follows:

(a) The S-2 Unit which was reported to be an 85 megawatt unit had been placed in "cold standby". The unit was in a state of readiness and would require 7 to 10 weeks to be placed on line. Mr. Anderson said that S-2 was projected to take three months to bring on line. (Anderson Vol. I TR. 208) S-2 had been selected for standby mode because it represented Sunflower's largest gas fired unit. (Thompson Vol. I, TR. 67-69)

(b) Mr. Thompson testified that the S-3 Unit was a Frame-5 General Electric combustion turbine which was used as a "black-start" unit. If the entire Sunflower system were to lose power, the S-3 Unit could be started on compressed air and used to start auxiliaries in Garden City and bring other turbines on line. The S-3 Unit was stated to be a 12 megawatt unit.

(c) Mr. Thompson stated that the S-4 and S-5 Units, both of which had a 50 megawatt rating were used as peaking units.

(d) The Garden City Units 1 and 2 are owned by Wheatland Electric Cooperative and leased to Sunflower. Garden City 3 is owned by the City of Garden City and is also leased to Sunflower. None of these units is in Sunflower's rate base. However, Sunflower makes lease payments to the respective owners. Garden City Units 1, 2 and 3 have ratings of 4, 7 and 11 megawatts respectively. (Thompson Vol. I, TR. 69-74)

(e) Mr. Novin visited the Holcomb Unit and in addition to a visual inspection of the plant including the turbine generator, he reviewed the engineering design documents and periodic logs. He stated that, based on his analysis, the Holcomb Unit had a 295.7 MWE net rated capacity (Novin Vol. III, TR. 368). Staff and Sunflower agree that the net rated capacity of the Holcomb Unit is 296 megawatts. The Commission finds that the Holcomb Unit has a 296 megawatt net rated capacity.

10. None of Sunflower's generating units listed in Paragraph 5 is planned to be retired in the next five years. (Anderson Vol. I, TR. 200) This position was confirmed by Mr. Thompson who stated that none of the units discussed above is being considered for retirement. (Thompson Vol. I, TR. 75)

11. The Commission finds that based on the evidence, Sunflower's 515 megawatt system generating capacity as filed with the Southwest Power Pool and reflected in the April 1, 1984 report is a reasonable representation of its current system capacity and shall be used by the Commission.

B. Firm Purchase and Sales

12. The contracts to purchase power from Kansas Power and Light Company (KPL) and Centel Corporation (CTU) were placed in the cost of service by the Applicant in this case. The Commission is aware that Sunflower chose not to request rate relief for both the KPL and CTU contracts in its last rate case, Docket No. 137,068-U.

The contracts were negotiated in 1979 and executed in April 1980. (Thompson Vol. I, TR. 76) The stated purpose for entering these contracts was to secure an interim power supply source until construction of Holcomb was completed. (Thompson Vol. I, Tr. 76)

13. The Commission notes that during the test year 50 megawatts was being purchased under the CTU contract and 55 megawatts from KPL. Presently the CTU contract requires Sunflower to purchase 25 megawatts through May 31, 1986 when the contract expires. The KPL contract pursuant to Service Schedule H presently requires Sunflower to purchase 55 megawatts through May 31, 1985. From June 1, 1985, Sunflower is required to purchase 15 megawatts until the contract expires May 31, 1986 (Thompson Vol. I, TR. 79).

14. When asked on cross-examination how many megawatts of KPL/CTU power Sunflower had taken during the test year, Mr. Thompson stated that Sunflower tried to remarket the power in Nebraska and had used power during periods of Holcomb outage. However, he further stated that Sunflower had not substantially used the power on a day-by-day basis to meet its own customer loads. (Thompson Vol. I, TR. 81)

Mr. Thompson further stated that presently the Holcomb Unit is being used to meet Sunflower's total system capacity. (Thompson Vol. I, TR. 74)

15. The Commission finds that when all factors are weighed, two factors are determinative. First, Sunflower has not substantially used the contract power to meet customer loads.

Second, the Holcomb Unit is used to meet Sunflower's system capacity. For these reasons, the Commission finds that the KPL and CTU contracts are not used and required to be used.

16. The terms of the contract require a four year written notice prior to termination by either party. (Thompson Vol.I, TR. 78) When asked what the purpose was for having a four year notice, Mr. Thompson said that the provision was designed to enable CTU to plan as far ahead as possible in its financial forecasting. (Thompson Vol. I., TR. 78) Mr. Thompson did state that in 1980 Sunflower considered that the Holcomb Unit could be put in service in mid 1984. Further, Sunflower believed that a one year overlap of the KPL/CTU contracts and the commencement of commercial operation of the Holcomb Unit would allow adequate time for possible slippage or delays in the Holcomb construction (Thompson Vol. I, TR. 79). In light of his own statement, Mr. Thompson was then asked whether Sunflower had, in fact, given notice in 1981 thus providing the projected one year overlap and terminating the contract in 1985. He admitted that Sunflower finally gave notice in 1982. Sunflower offered no explanation for giving notice in 1982 rather than 1981. Further, Mr. Thompson agreed that the four year notice provision which had been accepted by Sunflower made it very difficult for Sunflower to avoid costs even when Sunflower's management could project the Holcomb completion date. (Thompson Vol. I, TR. 79)

17. The Commission notes that the purpose of the notice provision was to benefit KPL/CTU and was a detriment to Sunflower. Under these circumstances, the management of Sunflower was on notice to remain constantly vigilant concerning the progress and projected completion date of the Holcomb Unit. In fact, the Holcomb unit was completed and was commercially operating in 1983. The facts of this case do not suggest management has acted vigilantly to monitor a known problem. The Commission finds that not only are the KPL/CTU contracts not used and required to be used but also that Sunflower management was

imprudent in its failure to closely monitor the completion date of the Holcomb Unit in order to give timely notice of termination of both the KPL and CTU contracts. For these reasons, the Commission finds that the costs of these contracts shall not be flowed through to Sunflower's ratepayers.

C. Reserve Requirement

18. The Southwest Power Pool requires an 18% reserve margin above system peak, while the MoKan Power Pool requires a 15% reserve margin above system peak. The Commission notes that if the loss of load probability (LOLP) analysis of a system is favorable, the system may qualify for a smaller reserve margin. (Pauley Vol. III, TR 328) The Commission encourages Sunflower to evaluate the possibility of qualifying for such a lower reserve requirement. However, the Commission is aware that presently Sunflower must meet the 18% reserve margin set by the Southwest Power Pool notwithstanding the lower reserve margins allowed or available elsewhere. Therefore, to recognize the most rigorous standard required of the utility and to use this standard in the Commission's analysis is reasonable. Consequently, the Commission finds that an 18% reserve margin for purposes of this order is reasonable and is hereby adopted.

19. The Commission hastens to add that as system interconnections, improvements, additions and aging occur, the actual reserve margin of a system will change. The Commission also recognizes the technical complexity of the factors which are considered by the power pools in setting reserve margins. For these reasons, the 18% reserve margin adopted for the analysis in this case is not to be assumed for purposes of other utilities in future rate cases. The Commission also directs staff to evaluate the standards used by the Power Pool in setting the reserve margins and to determine the factors which may assist in lowering the reserve margins without reducing either the quality or reliability of service to the ratepayers.

D. System Demand

20. Mr. Thompson further stated based on the 1984 summer peak, Sunflower will have peak responsibility of 291 megawatts if the same peak is experienced in 1985. Mr. Thompson contended that Sunflower would have 307 megawatts of capacity to meet that same 291 megawatt peak responsibility. (Thompson Vol. I, TR 20)

21. The peak demand for 1982, 1983 and 1984 as reported by Sunflower and reflected in Exhibit No. 21, was 250 MW, 249 MW and 247 MW respectively. The Commission finds these figures to be accurate and hereby adopts them for the analysis in this Order. The Commission also finds that the Sunflower system peak has been slightly declining during the most recent three years for which figures were available.

E. Performance Criteria

22. Mr. Thompson stated that if 60% of a 296 megawatt plant were placed in rate base, customers would be supporting a 177 megawatt plant. Further, he stated that Sunflower's test year load was 1,105 gigawatt hours. Of that total, 1,040 gigawatt hours were comprised of member load and 65 gigawatt hours were comprised of non-member load. He then calculated that to supply the test year energy requirement with a 177 megawatt unit would require the unit's operation at a 71% capacity factor. He then noted that an average capacity factor for coal fired plants of this size was 65.6%. (Thompson Vol. I, TR 20)

23. Mr. Thompson did stat that since December of 1983, the Holcomb Unit has been available 96% of the time. (Thompson Vol. I, TR. 22) Mr. Anderson confirmed that from December 7, 1983 through July 31, 1984, the Holcomb Unit's availability had been 96%. Also, during that same period the unit had produced 978,209 megawatt hours net. (Anderson Vol. I, TR. 174-175) Further Mr. Anderson stated that since May 1, 1984, the Holcomb Unit had

been operating at a level in excess of 250 megawatts on 35 days. And that the maximum Sunflower system load between May 1, 1984 and August 1, 1984 was 247 megawatts. Finally, the Sunflower system load had been over 175 megawatts during the May 1 through August 1 peak period on 43 days.

24. After completion of the start up period, and excluding the forced outage, the capacity factor of the Holcomb Unit during the test year was: 50.16% in August; 55.28% in September; 46.70% in December; 51.86% in January; 55.34% in February; 53.91% in March and 62.62% in April. The average capacity factor for the Holcomb Unit during these months was 53.69%.

25. Mr. Pauley's peak and reserve analysis examined the Sunflower system by using varying levels of generating capacity. The peak and reserve analysis used by Mr. Pauley reflects a method used by the Commission in its last Sunflower Order Docket No. 137,068-U.

26. Mr. Pauley recommended that 83.66 percent of the Holcomb Unit be placed in rate base. He stated that there were various factors which needed to be considered and several alternatives from which the Commission could choose (Pauley Vol. III, TR. 302).

27. Mr. Pauley did state that his recommendation was in the higher range of the performance standards examined by staff. The recommendation by staff to place nearly 84% of the Holcomb Unit in rate base was in large part due to the unique economic conditions of the Sunflower system, the Cooperative setting in which Sunflower existed and the optimal performance of the Holcomb Unit. (Pauley Vol. III, TR. 302)

28. To determine what portion of the Holcomb Unit should be placed in rate base, the Commission has reviewed a number of analytical relationships or indicators that can be drawn from the record. These indicators suggest that a percentage of the Holcomb Unit approaching, but slightly less than 60% is currently used and required to be used.

29. The first indicator reviewed by the Commission compares the Sunflower system's *current* available capacity with its 1983 peak demand *plus reserve*. The record indicates that Sunflower's system peak demand in 1983 was 249 megawatts. Adding an 18% reserve margin would result in a 294 megawatt peak/reserve requirement. Dividing the peak/reserve by the 515 megawatts of internal capacity results in 57% demand/capacity relationship.

30. The second indicator evaluated the capacity factor after inservice criteria was satisfied. This capacity factor was 55%.

31. The third indicator evaluated the average capacity factor of the Holcomb Unit in 1984 excluding scheduled outages. This amounted to a 55 percent capacity factor.

32. In light of the diversity of the positions taken, the Commission is concerned about the financial impact of placing only 40% of the Holcomb Unit in rate base.

33. The staff's economic rationale of placing 100% of the plant in rate base is both innovative and persuasive. However, the Commission must consider the financial effect on Sunflower's customers of such an increase. Clearly, the public testimony reflects that many industrial customers would leave the system and many residential customers, already hard pressed to meet utility payments, would be forced to pay more. The loss of customers is precisely what Sunflower does not need.

33. For these reasons, the Commission finds that placement of 57% of the Holcomb Unit in rate base is reasonable and is hereby adopted.

VII. GAS OPERATIONS

34. Sunflower included the natural gas gathering and transmission system in the application. Revenue from the resale of gas and the sale of liquid extraction products is not projected to be sufficient in early years to completely recover costs associated with the gas gathering and transmission facilities (Thompson Vol. I, TR. 30).

35. Sunflower claims to use the gas at the Holcomb Unit, the S-2 Unit, peaking units and reserve units and thus suggests that the Gas System is reasonably included in rate base (Thompson Vol. I, TR. 30).

36. Staff testified that the gas operations showed a test year loss of $2,532,684. Further, even if Sunflower's projected margins from next years gas sales are accurate, the company will experience a net loss in the gas operations. And Mr. Thompson agreed that using Mr. Armstrong's criteria, the net losses of the gas operation were acurately stated to be $1,679,754 (Armstrong Vol. III, TR. 76); (Thompson Vol. I, TR. 42).

37. The Commission notes that Sunflower excluded the gas operations from its last rate case, Docket No. 137,068-U. In that case, Mr. Keith testified that Sunflower would be charged a fee per unit for gas delivered. He stated that in this way the electric rate would not be burdened needlessly with the total cost of the gas system which was only partially used by the electric system.

Mr. Thompson stated that the gas operations were losing money but that Sunflower needed revenue to pay the debt and that those revenues had to come from the electric revenues or from the revenues generated from the resale of natural gas. (Thompson Vol. I, TR. 45)

38. Mr. Thompson stated that the gas supply was used to bring Holcomb Unit on and off line and provide backup for the Garden City generation. He admitted that the Holcomb Unit used relatively small amounts of natural gas (Thompson Vol. I, TR. 46). Further, he stated that the Garden City Units 1, 2 and 3 were not used during the test year. (Thompson Vol. I, TR. 71) Mr. Thompson and Mr. Anderson stated that the S-2 Unit had been placed in "cold standby", that the S-2 Unit would require two to three months to bring back on line; that Sunflower does not expect to use S-2 unless an extreme emergency arose where Holcomb was off line for six months or more; and that S-2 is not

anticipated to be used for three to five years assuming the load growth which has occurred in the 1980's. (Thompson Vol. I, TR. 28, 68; Anderson Vol. I, TR. 176, 187-188)

Finally, Mr. Anderson admitted that during Holcomb outages, Garden City 1, 2 and 3 and S-2 in the past had not been used, nor were they to be used in the future by Sunflower because Sunflower was able to purchase more economical energy from neighboring utilities. (Anderson Vol. I, TR. 182, 187)

39. The Commission notes that the S-2 Unit has been placed in cold standby and has not been used during the Holcomb Unit outages. The Garden City Units 1, 2 and 3 also have not been used during Holcomb outages. Rather than running its own units during Holcomb outages, Sunflower has been able to purchase more economical energy from neighboring utilities. The Holcomb Unit uses relatively small amounts of natural gas to bring it on and off line. The Commission finds the weight of the evidence supports the exclusion of the gas gathering system from rate base. Further, there is nothing in the evidence to show that the substantial losses of the gas gathering operations should be attributed to wholesale electric rates. Though the Commission believes such losses are not appropriately reflected in wholesale rates, there may be a recognition on the part of Sunflower's Cooperative members that institutional responsibility exists for the decisions made with regard to the gas gathering system. The Commission notes that the individual cooperative members are not unlike investors. Rather than continuing to rapidly accumulate patronage capital, Sunflower's members are strongly encouraged, on a prospective basis to assess themselves for gas system costs. The Commission is not suggesting that patronage capital already received should be reallocated but that the policy of the member cooperatives in the future reflect a slower growth of patronage capital in order to redirect revenues during this time of financial stress. Such a policy is not only forcefully advocated by the Commission, but also reflects individual management responsbility for the financial health of Sunflower.

VIII. RATE BASE

40. As discussed above, the Sunflower proposed effective rate base reflects a balance of utility investment as of the end of the test year plus the addition of 60% of the Holcomb Unit cost, less the proceeds of the Safe Harbor Lease.

41. Staff proposed six adjustments to rate base if 60% of the Holcomb Unit were placed in rate base. The adjustments proposed by staff were as follows:

(A) Adjustment No. 1 increases the reserve for depreciation by $3,780,967 to reflect Sunflower's pro forma, year end depreciation expense level. Sunflower increased actual test year depreciation expense to an adjusted year end level. However, Sunflower did not make the corresponding adjustment to increase accumulated depreciation reserve. Staff's adjustment synchronizes the depreciation reserve with Sunflower's annualized depreciation expense. If, for rate making purposes, depreciation expense is increased without a corresponding increase in accumulated depreciation, then the plant costs, less accumulated depreciation, will be over stated. This could result in excessive returns for the period in which the rates were in effect.

(B) Staff Adjustment No. 2 revises the format used by Sunflower in the presentation of the Holcomb Unit costs. Sunflower chose to include 100% of the Holcomb costs in rate base and then back out a portion of the resultant revenue requirement to get back to a level which would represent an effective level of 60% of the plant costs in rate base. Staff's adjustment reduces the rate base to a level which reflects the inclusion of 60% of the Holcomb Unit costs, and subsequently develops a revenue requirement based upon the approved rate base level. Staff believes that this adjustment which is similar to that utilized by both Sunflower and the Commission in Docket No. 137,068-U, more clearly reflects the level of the Holcomb Unit costs actually being considered for inclusion in rate base. This adjustment also includes the appropriate reduction in accumulated depreciation reserve. Further, $500,000 in investment in common plant has been eliminated to reflect the Commission's determination in Docket No. 137,068-U. This $500,000 represents funds spent on control facilities to accommodate a second Holcomb unit which is not used or required to be used at this time.

(C) Staff Adjustment No. 3 reflects a reduction in transmission plant of $23,679 and accumulated depreciation of $7,356. Staff's adjustment reflects a rate base treatment of the settlement in the Tomlinson lawsuit. These funds are scheduled to be received quarterly. However, because of the uncertainty associated with receipt of future payments, staff has reduced rate base and depreciation reserve only to reflect payments actually received. Staff's adjustment reflects a treatment which was accepted by the Commission in Docket No. 137,068-U.

(D) Staff Adjustment No. 4 removes from rate base all plant costs, pre-payments and materials and supplies related to the Sunflower gas operations. These adjustments are being made because the gas operation was not shown to provide any significant benefit to Sunflower's electric ratepayers and, in fact, the gas operations are imposing a substantial financial strain on the Sunflower system. Based upon test year data, the gas operations are being continued at a significant annual loss. Further, Sunflower chose to eliminate all gas plant investment from rate base in its previous rate case in Docket No. 137,068-U. The adjustment reflects a reduction in rate base of $9,700,350.

(E) Staff Adjustment No. 5 reduces coal inventory to coincide with the probable demand capacity of the Holcomb Unit reflected in Sunflower's responses to staff's data requests. Staff used the methodology accepted by the Commission in Docket No. 137,068-U. This method adopts a 90-day coal burn at 60% of the accepted annual capacity factor of the Holcomb Unit. The 296 megawatt Holcomb Unit is multiplied by the 60% annual capacity factor providing a total of 108 megawatts capacity. This level would require 120.7 ton hours x 90 days x 24 hours per day or 2,160 hours x 120.7 ton hours for a requirement of 260,712 tons x $24.85 which reflects a year end average cost per ton of the Sunflower coal purchased for a total cost of

$6,478,693. This figure is then multiplied by the expected capacity factor of 46% ratio over a 60% annual capacity factor for a .77% of total capacity available which amounts to $4,988,594. This figure is then subtracted from the coal inventory test year balance used by Sunflower in the application of $5,441,514 for a total adjustment of $451,920.

(F) Staff Adjustment No. 6 is to synchronize the test year Holcomb Unit Deferred Cost Amortization Expense and the Accumulated provision for Holcomb Unit Deferred Cost Amortization. The adjustment establishes the accumulated provision for these costs thus decreasing rate base by $274,396.

(G) Staff Adjustment No. 7 reflects staff's proposed adjustment to the cash working capital requirement under the 60% of the Holcomb Unit in rate base. This adjustment is contingent upon the Commission's acceptance of all staff's adjustments to operations. Staff's deduction of the 13-month average accrual of vacations and holiday pay from the indicated cash requirement varies from that requested by Applicant. Applicant utilized a deduction of 50% of the average property tax level. Staff contends that the accrued payroll vacations and holiday represent a source of cash working capital provided because the amount is included in the cost of service and billed monthly to ratepayers. Therefore, the accrual only becomes a cash item when payment is actually made, generally several months after receipt from the ratepayers. Consequently, the company has a source of cash working capital. Sunflower contested only those issues and adjustments relating to gas operation. The Commission, having examined the testimony of Mr. Armstrong supporting the adjustments to rate base, finds them to be proper and reasonable and hereby adopts Staff's Adjustments 1 through 7 to rate base. Having found above that only 57% of the total cost of the Holcomb Unit should be placed in rate base rather than the 60% as requested, the Commission finds that the proper rate base for Sunflower in this matter is $337,107,105. This figure reflects the reduction of the Safe Harbor Lease proceeds. Also reflected in this rate base figure are the required modifications to staff rate base Adjustment Nos. 2, 6 and 7 required by the Commission decision to include 57% of the Holcomb Unit costs in rate base instead of 60%.

IX. OPERATIONS

42. Sunflower's application was based on net operating revenues of $44,683,816. Staff proposed 17 adjustments to operations which would result in a total decrease of $26,187,593 and would result in a total of $18,496,223 from net operating revenue.

43. The adjustments to operations advocated by staff are as follows:

(A) Adjustment No. 1 increases the pro forma revenues by $33,485 to reflect a correction in Sunflower's current rate annualization computations. Revisions were made in quantifing the billing demand charges of Great Plains and Victory, two of Sunflower's members, to correctly apply the billing demand ratchet applicable to these two cooperatives.

(B) Adjustment No. 2 increases production costs by $14,460. Sunflower had estimated demand charges from Midwest Energy for the Ross Beach interconnect facilities at $5,013 a month when the actual charges amounted to $3,808 per month. Staff's adjustment reflects the actual figures rather than the estimates filed by Sunflower.

(C) Adjustment No. 3 reflects an overall decrease of $471,823 in the pro forma salary levels recorded by Sunflower for the test year. Included in this adjustment, staff removed all pro forma salary levels applicable to the gas system operations for the reasons previously stated. Gas operation salaries amounted to a reduction of $376,732. Staff's salary adjustment did not reflect any management time which may be assignable to the gas operations.

Further, Sunflower proposed a salary level which involves wage distribution between operations and construction. Sunflower did not use the actual test year payroll distribution to quantify the payroll adjustment. Sunflower used a pro forma account distribution based on the actual experience Sunflower had from January 1984 through April 1984 to reflect the change in system operations. Staff evaluated the actual salary distributions for the period from January 1984 through September 1984. The pro forma payroll figures also reflect an annualized 2 1/2% increase which was given in November 1983.

(D) Adjustment Nos. 4, 5 and 6 are a result of the elimination of the gas operation salaries and the shift in payroll distribution reflected in Adjustment No. 3. Adjustment No. 4 reduces by $61,216 the retirement in payroll insurance level attributable to the salaries eliminated. Adjustment No. 5 reduces by $11,363 the workmen's compensation level. Adjustment No. 6 reduces by $39,517 the payroll taxes required.

(E) Adjustment No. 7 eliminates the annualized depreciation expense of $1,000,489 associated with the gas operations from the cost of providing service to electric consumers. This depreciation is eliminated because the plant investment to which the depreciation was associated was removed in Adjustment No. 4 to rate base.

(F) Adjustment No. 8 eliminates all test year revenues associated with gas operations including Sunflower's pro forma Adjustment No. 18 to gas margins and all non-payroll related gas oper tion expenses except depreciation in the net amount of a $627,833 reduction in margins.

(G) Adjustment No. 9 reduces production expense by $90,607 by eliminating the non-recurring expense relating to the Jess Taylor Plant. This plant was shut down on December 31, 1983 and at the time of hearing, was being disassembled at the direction of Sunflower. The exclusion includes operation and maintenance expense of $83,202 and fuel expense in the amount of $7,405. Because the plant is no longer in operation, neither of these expenses should continue, thus on a pro forma basis, they have been eliminated. Further, staff acknowledged during cross examination that a revenue decrease of $7,405 would also have to be made to properly reflect this adjustment.

(H) Adjustment No. 10 eliminates $10,848 in the form of a recruitment fee and moving expense associated with hiring an assistant gas division superintendent.

(I) Adjustment No. 11 eliminates $85,054 of a non-recurring legal expense relating to the 1980 Dorchester Exploration lawsuit. The costs associated with Sunflower's defense in the lawsuit and all then written off. Therefore, no similar expenditure will exist beyond calender year 1983.

(J) Adjustment No. 12 of $262,054 reflects Sunflower's continued sale of fuel oil inventory. These sales which began in 1982 and continued beyond the test year result in a gain to Sunflower during the test year. The revenues generated from the sales provide a source of financing other operations and therefore are included as a revenue item. Because the members have financed the purchase of the utility fuel oil, they should recognize the benefits in the form of decreased member rates as a result of the profits from the sale of these assets. Sunflower has realized a gain of $146,750 in its last rate case, $262,054 in the current test year and in excess of $300,000 has been realized by Sunflower after the end of the current test year.

(K) Adjustment No. 13 reduces the Holcomb Unit depreciation expense by $5,209,107 to reflect 60% of the Holcomb Unit costs in rate base. This adjustment is necessitated due to the rate base format change reflected in Adjustment No. 2 to rate base.

(L) Adjustment No. 14 reflects staff's position that the revenue requirement computation must commence with 60% of the Holcomb Unit in rate base. Therefore, no adjustment is required to defer a portion of the revenue requirement. The adjustment removes $28,490,373 of revenue deferral recorded by Sunflower.

(M) Adjustment No. 15 reduces property tax and property insurance expense by $1,871,890 to reflect 60% of the Holcomb Unit costs in rate base.

(N) Adjustment No. 16 reduces operating revenues by $7,472,100. Sunflower requests this amount in interim rate relief and had recorded on a pro forma basis the receipt of these funds. However, the Commission denied interim relief and had recorded on a pro forma basis the receipt of these funds. However, the Commission denied interim relief thus compelling this adjustment.

(o) Adjustment No. 17 reflects a reduction of $1,240,800 on an annualized basis. The demand charges from KPL and Centel. The charges assessed by contract are scheduled to continue at a monthly rate of $622,675 until June of 1985 when the rate will drop to $467,575. Calculating a 12-month period from the date of the issuance of the order, these costs will run $1,395,900 below the level incorporated by Sunflower in its application.

44. With the exception of the gas operation adjustments, neither Sunflower nor the intervenors expressed opposition to these proposed adjustments. The Commission finds the testimony of Mr. Armstrong to be persuasive and finds that Adjustment Nos. 1 through 16 to operations are reasonable and proper and hereby adopts the same as adjusted to reflect 57% of the Holcomb Unit to be included in rate base. Adjustment No. 17 is not necessary as the contracts have been excluded as set out above. These conclusions result in test year pro forma margins of $25,305,435. Staff's testimony and exhibits reflected a 60% inclusion of the Holcomb Unit. However, the Commission has found that staff's adjustments to operations are to reflect 57% of the Holcomb Unit in rate base which causes changes in Adjustments No. 13, 14 and 15. The adjustments to rate base and operations are adopted as set forth in Appendix A which is attached to the Order and incorporated herein.

X. RATE DESIGN

45. Applicant proposed a rate design which includes a base monthly charge for each of the eight distribution cooperatives, a base energy charge for kilowatt hour (KWH) usage at or below the test year level, an excess energy charge for KWH usage in excess of the test year level, and a customer charge. The base portion,

i.e., the base monthly charge, base energy charge and customer charge, will collect all the costs or revenue requirement the Applicant is requesting in this application. (Keith, Vol. II, TR 130).

46. The base monthly charge is a fixed monthly charge. It was calculated, based on numbers in the proposed tariff, from an annual demand rate of approximately $18.50 per kilowatt (KW). (Keith, Vol. II, TR. 121). This fixed monthly charge is assessed on a member by member basis and is designed to collect costs associated with demand. In contrast to the conventional demand charge, the base monthly charge is fixed, the charge remains the same for a given cooperative, for a given month, regardless of whether the member's usage increased or decreased from the test year level. (Keith, Vol. II, TR. 120, 134). However, Sunflower contends that the base monthly charge as proposed in its tariff facilitates the selling of additional power over the test year level without incurring additional demand charges and it levelizes the members average per unit cost of power. (Keith Vol. II, TR. 62).

47 . The base energy charge would be priced, including the proposed ECA waiver at an effective rate of (base $.04874, ECA $.00718) 5.592¢ per KWH. If a member increases its power requirements on a monthly basis over that actually incurred in the test year, the member cooperative would be charged the excess rate for each KWH required over the base level. For every month except July, August and September, the winter rate of 3.5¢ per KWH would be assessed for each KWH consumed in excess of the base level. In the summer months, July through September, the usage in excess of the base level would be priced at 4.0¢ per KWH. (Keith Vol. II, TR. 63). Sunflower is committed to the excess rates and the base consumption level until September 1, 1988. (Keith, Vol. II, TR. 40). However, if the base level consumption becomes nonrepresentative or any member loses five percent (5%)

or more of that member's load, the base level will be adjusted proportionally. (Keith Vol. II, TR. 40, 68).

48. Given the current surplus of capacity that exists within the Sunflower system, Sunflower has designed rates aimed at promoting additional sales of power. Sunflower contends that the existing generating and transmission system will support a substantial quantity of sales in excess of current levels at a cost which is essentially fuel related. (Keith, Vol. II, TR. 42). In this particular filing, the Board of Trustees of Sunflower has, in an effort to spur additional sales, chosen to down play annual load factors. (Keith, Vol. II, TR. 153). Accordingly, Sunflower's proposed rate design encourages building on peak as well as off-peak and provides little incentive to manage load. (Keith, Vol. II, TR. 138).

49. Although Sunflower's proposed rate design is highly promotional, Sunflower could not quantify what members would be able to increase their consumption over the test year level and to what extent. (Keith, Vol. II, TR. 137). However, Mr. Dunn did testify that given the inelastic market in Sunflower's system, the quantity change that will result from the rate design will be small. (Dunn Vol. II, TR. 200).

50. Staff recognizes that Sunflower's proposed rate design is very promotional. (Ford, Vol. III, TR. 195). However, staff contends that the question to be addressed by the Commission is whether Sunflower should be allowed to promote additional sales and if so, to what extent. (Ford, Vol. III, TR. 194).

51. The objectives of staff's rate design are similar to Sunflower's, i.e., offering discounted rates to their members and increasing KWH sales. In keeping with Commission policy to conserve our resources for future generations, staff has taken a longer run approach in its rate design, thereby making it less promotional in the short run. (Ford, Vol. III, TR. 200). In designing its rates, staff was concerned with controlling additional sales on peak to prevent the less efficient, higher

cost, gas-fired turbines S-4 and S-5, from unnecessarily being brought on line resulting in increased fuel costs which would ultimately flow through the ECA clause to the distribution cooperative ratepayer.

52. Staff proposed a rate design which contains the more traditional components of a rate design. It contains a demand, energy and customer charge. Mr. Ford illustrates the proposed rate design in his schedules, marked as Exhibit 20. Therein, are staff's proposed tariffs under each scenario presented by staff, 47%, 60% and 100% of Holcomb in rate base.

53. Staff's energy charge is structured similar to Sunflower's, in that it contains a base/excess provision. However, the excess rate is computed differently. The excess rate shall be applied to any KWH purchased above the member's base monthly requirements for the corresponding month of the base period by cooperative. Additionally, Mr. Ford has included a provision in his rate design to phase the excess energy rate into the base rate, as the winter load on Sunflower's system approaches the base load capacity of Holcomb Unit No. 1. The base energy charge ranges from 4.305¢ per KWh under the 47% scenario to 5.334¢ per KWH under the 100% proposal. The excess energy charge varies from 3.229¢ per KWH to 4.0¢ per KWH respectively.

54. The demand portion of staff's proposed rate design differs substantially from that proposed by Sunflower. Staff proposes a base demand charge ranging from $17.8597 per KW (47% scenario) to $22.1263 per KW (100% proposal) to be assessed for all KW purchased during the summer period and any KW purchased during the non-summer period up to the base period. The summer season runs from June 16th through September 15th. Additionally, Mr. Ford recommends an intermediate rate (one-half the base demand charge) be applied to any KW purchased in the winter period above the test year level up to 50% of the highest coincident demand established by delivery point during the

preceeding summer period. For any KW purchased in the winter period above 50% of the highest coincident demand established by delivery point during the preceeding summer, an excess rate of one-third of the base demand charge shall be assessed.

55. Staff's rate design focuses primarily on improving the annual load factor of Sunflower while promoting additional sales. Accordingly, staff's demand rate was established to encourage the cooperative to control summer peak, thereby permitting the cooperative to achieve the excess winter demand rate more quickly. (Ford, Vol. III, TR. 200). Furthermore, the design encourages increasing winter load by pricing any usage above test year level at a discounted rate. Sunflower, through its cross-examination of Mr. Ford, implies that a demand charge on the excess kilowatt hours sold in the winter period have the impact of postponing or eliminating growth. However, Mr. Ford justifies the winter demand charge stating that such a charge recognizes the load that is placed on the system and properly prices that load. Even though placing a demand charge on winter usage is less promotional than Sunflower's rate design, Mr. Ford believes his rate design is still promotional. (Ford, Vol. III, TR. 222).

56. Historically, Sunflower's peak has been a three to four hour peak. (Ford, Vol. III, TR. 217). Sunflower contends that it does not make sense to discourage peak load even though it incurs some higher incremental costs for three to four hours, if in the process it makes additional off-peak sales. However, Mr. Ford contends that with effective load management, off-peak sales could be made without having to incur those additional higher costs. Because Sunflower's proposed rate design contains no demand charge associated with additional sales and, the higher fuel costs related to firing S-4 and S-5 are passed through to the ultimate consumer via the ECA clause, Mr. Ford contends that the members of Sunflower have little incentive to control the

load under Sunflower's proposed rate design. (Ford, Vol. III, TR. 218). Sunflower's rate design does not encourage load management as the only price signal provided is the 4¢ excess charge. Again, the Commission must emphasize the need to move away from promotional rates to a long-term conservation mode.

57. In the cross-examination of Mr. Ford, it is noted that Sunflower could avoid firing-up S-4 and S-5 by making economy purchases on an hour-by-hour basis. However, Mr. Ford testified that economy purchases are not firm, or reliable in that it can not be guaranteed from one hour to the next that a purchase can be made. (Ford, TR Vol. III, TR. 221).

58. The Commission acknowledges the participation as intervenors the distribution cooperatives of Sunflower. Great Plains, Lane-Scott, Northwest, Norton-Decatur, Pioneer and Wheatland prefiled written direct testimony and were subject to cross-examination. Mr. Ramsey, counsel for Lane-Scott, also made a special appearance for Harry A. Waite on behalf of intervenor Victory Electric. All of the member cooperatives expressed support for Applicant's revenue request. Additionally, with the exception of Pioneer Electric, the member cooperatives support Applicant's proposed rate design. The members generally felt that a promotional rate was appropriate where there exists excess capacity. Furthermore, those member cooperatives which have load management in place stated they would continue the practice of load management even though Applicant's rate design promotes buiding on peak. (Gerstner, Vol. II, TR. 252, 254; Ginther, Vol. II, TR. 297, 312). Mr. Ginther, manager for Northwest Electric, specifically opposed staff's rate design proposal because the increased demand charge in the summer time would be detrimental to persuading irrigators to get back on the system. (TR Vol. II, 302). Furthermore, Mr. Ginther opposed the proposal of Mr. Ford to determine the excess KW on a substation basis because based on past actual experience, Northwest has found substation control not to be feasible with load management. (Ginther Vol. II, TR. 302-03).

this rate design, the level at which the monthly billing demand units are subject to the base demand charge shall remain unchanged from the levels established during the test year.

64. In the Commission's order issued in Sunflower's last rate application, Docket No. 137,068-U, Sunflower was directed to apply any margins that it received from off system sales to offset deferral costs. The practice of offsetting deferral costs

59. Mr. Holt, manager for Pioneer Electric, testified that Pioneer supports the rate design proposed by staff. Mr. Holt opposes the rate design proposed by Sunflower primarily because it encourages random load building without taking into account Sunflower's peak capacity. (Holt Vol. II, TR. 335). Mr. Holt also opposes the fixed demand charge as proposed by Sunflower because it represents about 37 percent of Pioneer's total wholesale power cost and would be detrimental if load declines. (Holt Vol. II, TR. 335, 344). Mr. Holt stated that Pioneer further opposes the one-half cent differential in Sunflower's excess energy charge for winter and summer usage. Pioneer needs to sell more energy in the summer to improve its summer load factor and the higher wholesale excess energy charge in the summer would be counterproductive to Pioneer's objective. (Holt Vol. II, TR. 336).

60. The question to be addressed is to what extent Sunflower should be allowed to promote additional sales. It has long been and remains the policy of the Commission to encourage conservation and the wise use of the State's resources. The difficulty the Commission has in adopting Sunflower's proposed rate design is that it disregards load control and promotes usage at random without prudent long-term planning for responsible energy use.

61. Although the Commission does not intend to abandon conservation, it recognizes that within the Sunflower system there currently exists a significant mismatch between capacity and demand. For example, Sunflower's current summer peak is less than the base load unit, Holcomb. This underutilization of Holcomb is not an efficient means of generation. Consequently, some promotion is justifiable at this time, but not to the extreme that Sunflower's rate design suggests. There needs to be controlled promotion with the ability to phase-out promotional rates when capacity and demand begin to balance. Concurrent with a planned phase-out of promotional rates, greater effort needs to be made to market excess capacity to reach the balance between

with margins received from off-system sales should be continued. In addition, staff recommends that any incremental margins Sunflower collects as a result of an increase in original excess energy rates be used to offset deferral costs. Given the financial condition of Sunflower, the Commission finds that it is inappropriate to apply any incremental margins collected from the member cooperatives to offset deferral costs and; such incremental margins shall be used in the operation of Sunflower.

65. Staff testified that the fuel limits and alternative fuel ratios currently being used in Sunflower's ECA tariff do not reflect current generation mix. Staff recommended that Sunflower's tariff be changed to reflect current generation mix. (Ford Vol. III, TR. 20) The Commission finds such tariff updates to be reasonable and necessary. Further, the Commission directs staff to work with Sunflower in developing appropriate fuel limits and fuel ratios for Sunflower's ECA tariff.

XI. RATE OF RETURN

66. Sunflower, a generation and transmission (G&T) cooperative, has zero or near zero equity. The return on equity theories and the usual weighted cost of capital approach are not applicable. One must instead be concerned with the weighted cost of debt and the secondary standard of interest coverage ratios. This ratio is generally labeled TIER, or "Times Interest Earned Ratio". The TIER used to determine if interest has been covered to a degree sufficient to meet mortgage requirement is defined as:

$$\frac{\text{NET MARGIN} + \text{INTEREST EXPENSE}}{\text{INTEREST EXPENSE}}$$

For distribution cooperatives, the minimum TIER is 1.5; for G & T systems it is 1.0. The Applicant, however, has entered into a letter of credit agreement associated with its "Safe Harbor" lease which requires it to file rates which will produce a TIER of 1.05. Accordingly, this is the TIER the Applicant is requesting.

67. It has been the policy of the Sunflower Board of Trustees to file for the lowest required TIER during the rate phase-in of the Holcomb Unit. A TIER of 1.05 is the minimum requirement which Sunflower must request under the terms of the loan agreements between Sunflower, the REA and Irving Trust Company. Although a Times Interest Earned Ratio of 1.05 limits Sunflower's flexibility, Mr. Dunn testified that if it was actually earned, a TIER of 1.05 would be adequate for the phase-in period. (Dunn Vol. II TR. 169).

68. Staff recommends the Commission grant the Applicant a TIER of 1.05. Furthermore, staff believes it is important for Sunflower to maintain a zero or positive equity position. However, it should be noted that the Commission is not bound by Sunflower's financing covenant. The Commission finds that a TIER of 1.05 is reasonable and hereby adopts the same.

XII. OTHER ISSUES

69. Sunflower, as a rural electric cooperative generating and transmission utility, is made up of eight member cooperatives who in turn consist of their members who are also their ratepayers. Therefore, there are no stockholders to bear the burden of costs imprudently incurred. In the case of an investor-owned utility the Commission can, if it finds that costs were unreasonably or imprudently incurred, refuse to allow those costs to be recovered through rates, thus shifting the costs to the stockholders. Sunflower has no stockholders, only members who are the ratepayers. The inability of the Commission to utilize the safety value of shareholders further exacerbates an already difficult problem.

Much of the testimony in this case revolved around appropriate rate design policy. The Commission recognizes the benefits of resource conservation and the Commission encourages utilities to present rate designs that incorporate conservation measures in the context of existing generation capacity. Because of Sunflower's unique condition, other jurisdictional utilities should not rely upon the facts in this case in developing strategies for future cases.

70. The Commission recognizes that presently the retail rates paid by Kansas customers in Sunflower's service territory are already high compared to rates paid by other Kansas customers. Rates for Sunflower's customers are at the outer edge of what the market place can sustain. Though Sunflower's management has done much to control costs, for which they should be commended, the statements taken at the public hearings reflect a unanimity on the part of ratepayers that cannot be satisfactorily addressed merely by cost control measures of the type undertaken by Sunflower. Until the underlying problems of high capital costs and high financing costs are addressed, no remedy will provide a long term solution.

71. Some have suggested that the Sunflower Office Building, the subject of much ratepayer concern and newspaper coverage is an example of poor management. However, the Office Building is not a part of this rate case. Yet, the symbol such a capital expenditure represents, is not helpful. The Commission notes that Sunflower's management has been cautioned to make every effort to control costs in keeping with the utility's present financial position.

72. Some have suggested that the solution to Sunflower's conundrum is to "mothball" the Holcomb Unit and to make economy purchases from other utilities. Under this method, capital costs of the Holcomb unit would continue as would the growth of the financing costs. In addition, electricity would have to be

purchased off system. This method ignores payment of the capital costs which have been incurred. Further, it overlooks the repayment provisions to which Sunflower has contracted and it requires additional revenues to purchase power. For these reasons, the concept of "mothballing" the Holcomb Unit is not economically feasible.

73. The Commission notes that Sunflower has continued to explore the possibility of off system sales as reflected by Sunflower's negotiations with KEPCo. The Commission encourages further *efforts to seek off system energy markets. However,* these efforts cannot alone be expected to be the solution to Sunflower's financial dilemma.

74. Anything short of a substantial increase in the customer base or a substantial reduction in the interest charges presently required on the Federal Financing Bank (FFB) financing are helpful but do not solve the major problem. The Commission notes that current Federal policy runs contrary to increasing REA participation or reducing the current rate of interest on the FFB loan. Instead, Federal policy encourages the use of private markets. Such a policy does not appear to be helpful in addressing the problems faced by Sunflower.

75. The Commission recognizes that a slight decrease in the interest rates associated with Sunflower's Federal Financing Bank (FFB) loans has significant benefits both to the Company and its members. For example, a one-half percent decrease in the FFB interest rate would provide the opportunity to place an additional $16,000,000 of the Holcomb Unit in rate base with no effect on Sunflower's revenue requirement. The greater the reduction in interest, the greater the long-term benefit to Sunflower and its members. Therefore, the Commission strongly encourages Sunflower to continue to explore all methods to reduce the interest rates associated with its debt.

76. For these reasons the Commission must actively work with Sunflower in seeking a solution. The Commission hereby authorizes the Chairman to gressively seek out assistance for Sunflower and its customers. Action must be taken to address the issues outlined in this Order.

77. The Commission commends the many conscientious ratepayers who took time from their busy schedules and came to the Sunflower public hearings. Those who testified provided the Commission with invaluable information which directly affected the outcome of the case. The comments were, for the most part, well reasoned and persuasive. The unanimity with which the ratepayers expressed the problems they face with high utility rates had a significant impact on the Commission.

XIII. CAPITAL STRUCTURE

78. Staff proposed three adjustments to the capital structure costs presented by Applicant. First, a number of FFB notes have been "rolled over" since the application was filed. The new interest rates were incorporated lowering the weighted FFB cost of debt to 10.90% from 10.96%.

The second proposed adjustment removes the Irving Trust borrowing from the capital structure used to support general operations. In the order in Docket No. 140,008-U, it is stated in paragraph 2 that the sole purpose of the Irving Trust loan is to finance the carrying costs of the deferred portion of the Holcomb Unit No. 1. Therefore, it is staff's opinion that it should not be included in the computation of weighted cost of Sunflower's general borrowing applicable to general operations.

Adjustment No. 3 removes the funds associated with the financing of gas operations from the computation of interest to be covered by electric operations. This is similar to the Applicant's adjustment in Section 7, Schedule 2 of the application where funds applicable to the financing of CWIP are removed.

79. In addition, during cross examination, Mr. Armstrong acknowledged the need to revise the embedded cost of CFC borrowing to 10.125% from 9.04% shown on Schedule O of Exhibit 15.

80. Further, Applicant argued that the cost of borrowing used to finance gas plant investment carried an embedded cost of 5% as opposed to the 9.48% utilized by Mr. Armstrong. With the above adjustments, the weighted cost of debt is determined to be 9.234% at a TIER of 1.08 or 9.696% at a TIER of 1.05.

81. On Schedule P of Exhibit 15 sponsored by Mr. Armstrong, it was argued that 3.23% of the rate base of Sunflower Electric was supported by equity and not debt and thus in developing the interest cost applicable to rate base only 96.77% of the rate base should be considered.

Applicant argued that the equity was rapidly dwindling and should not be treated in the manner suggested by staff.

82. The Commission finds that staff's Adjustments No. 1, 2 and 3 to capital structure are reasonable and are hereby adopted.

Further, the Commission finds that the appropriate embedded cost of CFC borrowing is 10.125 percent.

Also, the Commission concurs with Applicant and finds that the appropriate embedded cost of borrowings used to finance the gas plant is 5 percent.

Finally, the Commission finds that Applicant's arguments are persuasive and that staff's argument regarding equity contained in Schedule P, Exhibit 15 is rejected.

IT IS, THEREFORE, BY THE COMMISSION ORDERED AND ADJUDGED THAT:

1. Applicant is a public utility subject to the jurisdiction of this Commission pursuant to K.S.A. 66-101 et seq., and under the authority granted therein, this Commission is empowered to permit changes in Applicant's tariffs.

2. Each of the specific findings hereinbefore made are hereby adopted as findings of fact and conclusions of law.

3. The application of Sunflower Electric Cooperative, Inc., for approval to make certain changes in its charges for sales of electricity at resale to its member cooperatives is granted in part and denied in part as set forth in the above findings and the appendix attached hereto.

4. The Commission authorizes and orders Applicant to submit new tariffs designed to generate additional gross revenues of $7,380,470.

5. The tariffs shall be consistent with the findings herein and shall be submitted to the Commission for review. The tariffs shall be effective upon approval by the Commission for sales rendered on or after the date of approval of the tariffs by the Commission.

BY THE COMMISSION IT IS SO ORDERED.

Lennen, Chmn. (Concurring); Wright, Com.; Henley, Com.

Dated: April 2, 1985

Judith McConnell

JUDITH McCONNELL
EXECUTIVE SECRETARY

SEAL

MRA:rh

In the Matter of the Application of)
Sunflower Electric Cooperative, Inc. for)
approval of the Corporation Commission to) DOCKET NO.
make certain changes in its charges for) 143,069-U
sale of electricity to its member)
cooperatives.)

CONCURRING OPINION
MICHAEL LENNEN, CHAIRMAN

While I concur with the majority of the members of the Commission in the disposition of this case, I feel comment is necessary regarding one aspect of the order.

The exclusion of costs associated with the KP&L/CIU purchased power contracts and the concomitant inclusion of 57% of the Holcomb No. 1 Unit in the rate base is a matter of concern for the following reasons:

1. During the period of time when rates established by this order can be expected to remain in effect, this action will impose higher costs on Sunflower customers than would a decision authorizing payment of the contracts and placing 53% of the Holcomb Unit in rate base, as initially adopted by the Commission.

Commencing June 1, 1985, through May 31, 1986, the 57% approach will result in an estimated annual rate increase of $7.38 million. For that same period, the 53% inclusion plus payment of the KP&L/CIU contracts would result in an almost identical rate increase of $7.46 million. However, the KP&L/CIU contracts expire on May 31, 1986, leaving a permanent increase in the amount of $4.1 million, a significantly lower increase than is authorized by this order. Only in April and May of 1985, would the "53% plus contracts" approach result in discernibly higher rates for Sunflower's customers.

2. The record is essentially devoid of support for the conclusion that Sunflower's decisions to enter into the contracts and to refrain from canceling them until 1982 were imprudent. To the contrary, the contracts themselves received Commission review and approval in 1980. (Docket No. 123,413-U) Moreover, my colleagues lay claim to greater prescience than I in their certainty that Sunflower should reasonably have known in early 1981 that the Holcomb Unit would be commercially operational in September 1983 and that the plant's subsequent performance when coupled with lack of demand growth on the Sunflower system would have essentially obviated the need for firm power from the KP&L/CTU contracts in 1985.

3. While the Commission technically has neither abrogated the contracts, something which legally it could not do in this proceeding, nor advised Sunflower to cease making payments in accordance with the contractual terms, the order, however unintentionally, appears to sanction a course of conduct by Sunflower that can only be expected to result in litigation among the three jurisdictional utilities who are parties to these contracts.

4. In recent months, both KP&L and CTU filed rate stability plans that were approved by the Commission. What effect the potential loss of Sunflower revenues may have on the respective rate stability plans of these utilities can only be surmised at this time. In no event could the effect be salutary.

5. I have serious reservations about the soundness of applying the "used and useful" test to contracts for purchased power which are expense items rather than property included in the rate base of the system.

The court, in Kansas Gas and Electric v. State Corporation Commission, 218 Kan. 670, 544 P.2d 1396 (1976), seems to suggest that the used and useful test applies to rate base items.

> "...[t]he duty and authority of the Commission is to ascertain the reasonable value of all property of the utility used or required to be used..." "If it is used or required to be used, the total reasonable value of the property must be included in the rate base..." Id. at 674.

A similar indication appears in the earlier case of Southwestern Bell Tel. Co. v. State Corporation Commission, 192 Kan. 39, 386 P.2d 515 (1963). There the court first states:

> "In a seriously contested rate investigation there must be a determination of (1) a rate base, (2) a fair rate of return, and (3) reasonable operating expense." Id. at 46.

The court later explains:

> "The dispute over the rate base, particularly the formula by which it is to be determined, presents the chief controversy in this case. This controversy hinges on the interpretation of G. S. 1949, 66-128, which provides:
>
> > 'Said commission shall have the power and it shall be its duty to ascertain the reasonable value of all property of any common carrier or public utility governed by the provisions of this act used or required to be used in its ascertainment of such value necessary in order to enable the commission to fix fair and reasonable rates, joint rates, tolls and charges, and in making such valuations they may avail themselves of any reports, records or other things available to them in the office of any national, state or municipal officer or board.'
>
> Id. at 50."

Thereafter, the court embarks on an extensive analysis of methods for valuing property included in a utility's rate base.

As a matter of legal analysis, I believe that the more appropriate test for ascertaining rate treatment of expense items is whether such expenses were reasonably and prudently incurred, not whether they are used and useful.

In sum, the choice of the 57% rate base treatment, while providing no relative benefit to Sunflower's customers, appears to foster litigation among Kansas jurisdictional utilities and to place a higher priority on meeting the requirements of Sunflower's financiers than upholding contractual obligations among Kansas utilities--a result that I do not find to be desirable.

While concurring in the overall result achieved by this order, I believe that the exclusion of the KP&L/CTU contract costs adds uncertainty and difficulty to a situation which needs no additional infusion of either condition. Had the order in this case reflected the inclusion of the KP&L/CTU contract costs and 53% of the Holcomb Unit in rate base, I believe that these conditions could in some measure have been ameliorated.

Michael Lennen
Chairman

Exhibit DB-4

I CERTIFY THAT THIS
IS A TRUE COPY OF
THE ORIGINAL
Helen Vance
PUBLIC SERVICE COMMIS

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

BIG RIVERS ELECTRIC CORPORATION'S NOTICE OF CHANGES IN RATES AND TARIFFS FOR WHOLESALE ELECTRIC SERVICE AND OF A FINANCIAL WORKOUT PLAN	))))	CASE NO. 9613

INDEX

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

BIG RIVERS ELECTRIC CORPORATION'S NOTICE OF CHANGES IN RATES AND TARIFFS FOR WHOLESALE ELECTRIC SERVICE AND OF A FINANCIAL WORKOUT PLAN	))))	CASE NO. 9613

O R D E R

PREFACE

On August 7, 1986, Big Rivers Electric Corporation ("Big Rivers") filed an application with the Commission requesting authority to increase its rates for wholesale electric service rendered on and after September 6, 1986, based on a restructuring of its debts. The application states that the proposed rates would increase Big Rivers' annual revenues by approximately $7.5 million, an increase of 3.58 percent over normalized revenues.

The Commission suspended the proposed rates until February 6, 1987, in order to conduct an investigation and hold public hearings on the reasonableness of the proposed rates. By agreement of the parties, in response to the Commission's request, the suspension period was extended to March 17, 1987. Motions for full intervention were filed by the Utility and Rate Intervention Division of the Office of the Attorney General ("Attorney General"), National Southwire Aluminum Company ("NSA"), Alcan Aluminum Corporation ("Alcan"), Utility Rate Cutters of Kentucky ("URCK"), Hancock County, Kentucky, City of Hawesville, Kentucky, Willamette Industries, Inc. ("Willamette"), Commonwealth Aluminum Corporation ("Commonwealth"), and Alumax Aluminum Corporation ("Alumax"). Firestone Steel Products Company ("Firestone") moved for limited intervenor status. All motions to intervene were granted by the Commission.

Public hearings were held at the Commission's offices in Frankfort, Kentucky, commencing on December 2, 1986, and concluding on December 18, 1986. During the public comment portion of the hearing, statements were presented by Honorable Danny Boling, Hancock County Judge Executive, Thomas McCord, International Representative of Aluminum, Glass and Brick Workers International Union, Vicki Basham, Superintendent of Hancock County Schools, and Honorable Josephine Hagin, Mayor of Lewisport, Kentucky. Statements were also presented by counsel for Hancock County and Firestone. The parties sponsored testimony at the hearing by the following witnesses:

Big Rivers	William H. Thorpe - General Manager
	Paul A. Schmitz - Vice General Manager, Finance
	Joe Craig - Fuels Manager
	Ron Johnson - Vice General Manager, Corporate Services and Labor Relations
	Joseph Dolezal - Vice General Manager, Energy Supply
	Frederick L. McCoy - Ernst and Whinney Utility Group
	Herbert Vander Veen - Ernst and Whinney Utility Group
	Herbert F. Jacobs - Vice President, Manufacturers Hanover Trust Co.

	Thomas B. Heath - Assistant to Deputy Administrator, Rural Electrification Administration
	Phillip B. Layfield - Ernst and Whinney
	Paul H. Raab - Ernst and Whinney
	Bernard L. Uffelman - Peat, Marwick, Mitchell and Company
	Douglas P. Sumner - Peat, Marwick, Mitchell and Company
	Robert F. McCullough - Manager of Regulatory Finance at Portland General Electric
	John D. Hightower, Jr. - Southern Engineering Co.
	Bernard J. Duroc-Danner - Arthur D. Little, Inc.
NSA	Howard W. Pifer, III - Putnam, Hayes & Bartlett, Inc.
	Joseph S. Graves - Putnam, Hayes & Bartlett, Inc.
	Allan J. Schultz - Casazza, Schultz & Associates
	Roger M. Whelan - Verner, Hiipfert, Bernhard, McPherson and Hand
	Robert P. Matusiak - Director of Planning and Analysis, National Intergroup, Inc.
	Kenneth T. Wise - Putnam, Hayes & Bartlett, Inc.
Alcan	Paul D. Belanger - Manager, Alcan Sebree Plant
	Maurice Brubaker - Drazen-Brubaker Associates, Inc.
	Christian K. Albrecht - Drazen-Brubaker Associates, Inc.
	H. Clyde Allen - Drazen-Brubaker Associates, Inc.
	James A. Ross - Drazen-Brubaker Associates, Inc.
	Stewart R. Spector - President, The Spector Report, Inc.
NSA & Alcan	Sam F. Rhodes - Touche Ross & Co.

Attorney General	Randall J. Falkenberg - Kennedy and Associates Lane Kollen - Kennedy and Associates
Alumax and Commonwealth	Charles F. Phillips, Jr. - Professor at Washington and Lee University
Alumax	Clyde M. Griggs - Manager, Alumax Hawesville Rolling Mill
URCK	David H. Kinloch - Consultant

Initial briefs were filed on January 21, 1987, and reply briefs on February 2, 1987. The Commission incorporated by reference and made a part of the record in this case Big Rivers' past two rate applications, Case No. 9006[1] and 9163,[2] and the D. B. Wilson Generating Station certificate proceeding, Case No. 7557.[3]

Big Rivers is a non-profit cooperative corporation engaged in the generation, transmission and sale of electricity, through four

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1 Case No. 9006, Big Rivers Electric Corporation's: (1) Notice of Change In Its Rates And Fuel Adjustment Clause Base For Electricity Sold To Member Cooperatives, and (2) Application For Authority To Issue Notes Or Other Evidences Of Indebtedness, and (3) Application For Approval Of Sale And Leaseback Of Its D.B. Wilson Station Generating Unit 1 And Associated Facilities.

2 Case No. 9163, Big Rivers Electric Corporation's Notice Of Change In Its Rates For Electricity Sold To Member Cooperatives.

3 Case No. 7557, Application Of Big Rivers Electric Corporation For: (1) A Certificate Of Convenience And Necessity Under KRS 278.20 And 807 KAR 1:010, Section 7 And 8 To Construct And Operate The Following Facilities: (a) Two Additional Generating Units, Each Having A Net Rated Capability of 395 MW To Be Known As The "D.B. Wilson Generating Station" And To Be Located In Ohio County, Kentucky. (b) Any And All Appurtenant (Footnote continued)

distribution cooperatives, to approximately 75,000 customers in 22 counties in Western Kentucky. Big Rivers derives approximately 70 percent of its member revenues from two industrial customers, NSA and Alcan, both engaged in the smelting of aluminum.[4]

BACKGROUND OF D. B. WILSON GENERATING STATION

Big Rivers' 1977 Power Requirements Study indicated that rural load would continue to increase at 9.97 percent through 1991 and industrial load would increase by 167 megawatts (MW) over the 1976 level of 665 MW. Total demand on the system was expected to be 1509 MW by 1986 and 1832 MW by 1991. With the two generating units at the Green Generating Station scheduled to be in service in 1979 and 1981, respectively, total plant capacity would be 1235 MW. This study predicted capacity shortages of 274 MW in 1986 and 597 MW in 1991 excluding any reserve capacity needed to maintain system reliability.[5]

In February 1978, Southern Engineering Company was employed by Big Rivers to determine its capacity needs and make expansion recommendations. The study was completed in 1979 and Southern

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[3] (continued)
And Related Equipment And Facilities, (2) A Certificate Of Environmental Compatibility Under KRS 278.025 For The Facilities Described In Paragraph (1) Hereof. (3) Authority To Borrow From The United States Of America, Through The Rural Electrification Administration (REA), Or The Federal Financing Bank Or The Eligible Lender The Sum Of $928,754,200 To Be Used For The Construction Of The Facilities As Further Described In The Application And Record.

[4] $82,654,460 from NSA plus $60,908,446 from Alcan divided by $208,296,183, total member revenue, Exhibit 4, page 2.

[5] Big Rivers' Response to NSA's Second Request for Information, Item 264, pages 2-3.

recommended that two 395 MW steam electric generating units be added to the system, one in 1984 and the other in 1986.[6] In June 1978, prior to completion of the study, Big Rivers requested a proposal from Burns and Roe to design a generating unit of approximately 350 MW to be scheduled for commercial operation in 1984. In December 1978, Big Rivers entered into a contract with Burns and Roe to design a 440 MW gross, 395 MW net, output rated unit. In May 1979, Big Rivers contracted with Westinghouse to purchase a turbine generator. The contract with Westinghouse gave Big Rivers 6 months to cancel before incurring any large cancellation penalties. Big Rivers stated that this provision was necessary to allow it adequate time to complete loan studies and make any necessary changes in the unit rating.[7]

On June 17, 1980, the Commission entered its Order in Case No. 7557, granting Big Rivers a Certificate of Public Convenience and Necessity to construct Wilson units 1 and 2. Shortly thereafter, Big Rivers began another comprehensive load forecast, the 1980 Power Requirements Study, which was completed in March 1981. The new forecast showed that load growth would increase at an annual rate of 3 percent, not the 9.97 percent predicted in the 1977 Power Requirements Study.[8] Based on the results of this forecast Big Rivers' Board of Directors voted to suspend the

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6 *Ibid.*, page 4.

7 Thorpe Rebuttal Testimony, Volume I, pages 15-18.

8 Big Rivers' Response to NSA's Second Request for Information, Item 264, pages 6-7.

construction of the Wilson Unit No. 2 in April 1981, and ultimately cancelled it. Big Rivers subsequently decided to continue construction of Wilson Unit No. 1 ("Wilson") based on the potential increase in loads due primarily to the addition of a fourth potline by ARCO [predecessor of Alcan] and, an analysis indicating that the cost to delay commercial operation was approximately $90 million per year.[9]

During 1982-83 aluminum prices took an unexpectedly deep and prolonged drop which led both aluminum smelters to shut down one of their potlines. The record reflects that during this period Big Rivers' Board of Directors and Rural Electrification Administration ("REA") representatives were regularly advised of Wilson's construction progress.[10] By late 1983, aluminum prices rebounded and the smelters' load returned to normal.

In an attempt to reduce the rate impact from Wilson, Big Rivers' attempted to execute a sale/leaseback (leveraged lease) of the Wilson Plant in 1984. The sale/leaseback arrangement with the General Electric Credit Corporation would purportedly have resulted in savings of approximately $700 million over a 35-year period. The savings were to be attributable to provisions of the Internal Revenue Code which would have allowed the purchaser of the property to share tax benefits with Big Rivers resulting from accelerated depreciation, energy credits, and investment tax

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9 Ibid., Item 264, page 7.

10 Ibid., page 9, and Rural Electrification Administration Field Activities Report of Mike Norman to Vincent Kaminski, dated October 9, 1982.

credits. Under this arrangement, Big Rivers' effective interest cost would have been lowered from an estimated 11.5 percent to 7.9 percent.[11] This was expected to save ratepayers $700 million over the plant's life.[12] However, Big Rivers was unable to resolve a number of major points and the sale/leaseback was abandoned.

In April 1984, Big Rivers filed a rate application, Case No. 9006, requesting additional revenue of $48 million under the scenario of a sale/leaseback for Wilson or, alternatively, $57.6 million without a sale/leaseback. Due to Big Rivers' financial inability to consummate the sale/leaseback and strong opposition to the rate increase voiced by NSA and Alcan, the application was voluntarily withdrawn.[13] Aluminum prices again sharply declined in 1984 and Big Rivers took the position that higher rates could result in the shutdown of the smelters.[14]

In November, 1984, Big Rivers filed another rate application, Case No. 9163, requesting a $16.7 million increase in rates. Big Rivers did not seek to recover any of the costs associated with Wilson except those related to two high voltage transmission lines tying Wilson into Big Rivers' system.[15] Mr. Thorpe testified that the Wilson costs were excluded in that case because Big Rivers

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11 Case No. 9006, Big Rivers' Application.

12 Big Rivers' Response to NSA's Second Request for Information, Item 264, page 9-10.

13 Case No. 9163, Order issued May 6, 1985, page 3.

14 Big Rivers' Response to NSA's Second Request for Information, Item 264, page 10.

15 Case No. 9163, Order issued May 6, 1985, page 1.

recognized that: (1) no economically viable solution had been reached to solve its financial problems; and (2) NSA and Alcan might go out of business if their rates increased.[16]

In November 1984, REA refused to advance any additional committed loan funds to Big Rivers. According to Big Rivers this rendered the utility incapable of using loan funds to pay the contractors for work completed at the Wilson Plant. Big Rivers subsequently filed suit against REA to release the committed loan funds.[17] In order to complete construction of Wilson, Big Rivers used internally generated funds and suspended its loan payments to REA. Big Rivers contended that having an income-producing asset was preferable to abandoning that asset and writing off approximately $700 million.[18]

On January 3, 1985, REA notified Big Rivers that it was in default on loan payments as of November 23, 1984, and asked for full payment of indebtedness of approximately $1.1 billion.[19] On January 18, 1985, the Justice Department, acting on REA's behalf, filed a foreclosure action against Big Rivers in the U.S. District Court, Western District of Kentucky.[20]

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16 Thorpe Direct Prepared Testimony, pages 6-7.

17 Big Rivers v. Harold Hunter, Administrator of the Rural Electrification Administration, Civil Action No. 84-0317-O(J), U.S. District Court (W.D. KY.)

18 Big Rivers' Response to NSA's Second Request for Information, Item 264, pages 12-13.

19 Ibid., page 13.

20 United States of America v. Big Rivers Electric Corporation, Civil Action No. C85-0012-O(J), U.S. District Court (W.D.KY.).

By Order entered May 6, 1985, the Commission denied Big Rivers' proposed rate increase, recognized that a financially viable solution for Wilson costs would need to be developed, and directed Big Rivers to negotiate with NSA and Alcan to develop flexible power rates that would reflect the market price of aluminum.

In early August, 1986, Big Rivers negotiated a Debt Restructuring Agreement (workout plan) with its creditors in an attempt to solve its financial problems and resolve the pending litigation with REA.[21]

REVENUE INCREASE

Big Rivers' rate application states that the proposed rates will increase annual revenues by $7,452,524 or 3.58 percent based on a 1985 test year.[22] In calculating this revenue increase, however, Big Rivers offset the proposed increase by a $15,462,514 reduction in its fuel expense.[23] This significant reduction in fuel expense was achieved in 1986 by renegotiating existing coal contracts and executing new, lower cost coal contracts. While Big Rivers should be commended for taking the initiative to reduce its largest operating expense, the Commission is concerned that Big Rivers' rate application does not accurately reflect the magnitude

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21 Big Rivers' Response to NSA's Second Request for Information, Item 264, page 15.

22 Application, Exhibit 4, page 1.

23 The $15,462,514 consists of a $12,635,946 reduction in Fuel Adjustment Clause expense and a $2,826,568 reduction in base fuel revenue. See Application, Exhibit 5, page 1, Pro Forma Adjustments.

of the proposed rate increase. All of these savings from reductions in coal costs are required to be flowed back to the ratepayers through the prior reduction of base rates under fuel adjustment clause regulation, 807 KAR 5:056. The ratepayers have and will continue to benefit from these reduced fuel expenses independently of this rate case.[24] Consequently, the offsetting of a proposed increase in rates by a required decrease in fuel revenue is misleading and impermissible. Once the fuel revenue is disregarded, as it must be, Big Rivers' rate application actually seeks a $22,915,038 or 11 percent annual revenue increase.[25] Further, the workout plan requires additional rate increases in 1989 and 1991.[26]

NSA COMPLAINT

On October 2, 1985, NSA filed a formal complaint against Big Rivers, Case No. 9437, National-Southwire Aluminum Company v. Big Rivers, requesting a reduction in the rates that had been approved by the Commission on May 6, 1985, in Case No. 9163.

The complaint states two grounds in support of reduced rates: (1) revenues from a 54 megawatt off-system sale to the Municipal Energy Agency of Mississippi ("MEAM"), which had been excluded for rate-making purposes in Case No. 9163 and attributed to the Wilson Plant, should now be considered for rate-making purposes because

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24 Hearing Transcript, Volume II, pages 33-34.

25 $7,452,524 plus $15,462,514 divided by 1985 actual revenues of $208,296,183 as shown on application, Exhibit 4, page 2.

26 Big Rivers' Response to NSA's Second Request for Information, Item 281, page 9.

Big Rivers has the generating capacity to accommodate that sale; and (2) Big Rivers' failure to reduce its per-ton cost of coal by either renegotiating existing contracts or filing bankruptcy to void the contracts. NSA requested that any rate reduction granted be first applied to reduce NSA's rate from approximately 28 mills to 22 mills due to: (1) its need for a 22 mill rate to insure its continued financial viability; (2) its prior subsidization of Alcan and its predecessors resulting from Big Rivers' 1981 rate increases to include the costs of the Green 2 generating unit constructed to serve Alcan's predecessors; and (3) the willingness of NSA's corporate parents to guarantee performance by NSA of its long term power supply contract.

NSA subsequently amended its complaint to allege that while Big Rivers has been collecting rates that were designed to recover the debt service requirement for its system excluding Wilson, little if any debt service payment has been made. An investigation was sought into the "diversion of revenues intended for debt service to other undisclosed purposes...."[27] A Second Amended Complaint was filed by NSA to delete its request for a 22 mill preferential rate and seek reduced rates for all customers. After a period of extensive discovery and the filing of prepared testimony, NSA's complaint was consolidated with Big Rivers' rate application by Commission Order entered August 14, 1986. The consolidation was pursuant to a motion by Big Rivers filed on August 7, 1986, in Case No. 9437.

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27 NSA Amended Complaint, page 5.

NSA MOTIONS TO DISMISS

NSA filed a motion and a supplement thereto to dismiss Big Rivers' rate application on multiple grounds attacking the merits of the workout plan. Big Rivers opposed NSA's motions and stated that the issues were more appropriate for resolution in the rate case hearing.

By Order entered September 16, 1986, the Commission held the motions in abeyance, finding that they raised substantial issues of fact not readily determinable prior to the scheduled evidentiary hearing. Based on the Commission's findings on the workout plan, set forth in detail below, NSA's motions are rendered moot and should be denied.

COMMISSION CONCERNS

This case presents some of the most difficult and momentous issues ever considered by this Commission. Despite all parties' appeal to traditional rate-making principles, this is clearly no ordinary rate case. The repercussions of our decision on the economic life of Western Kentucky have weighed heavily in our deliberations in this case.

The uneven load distribution of the Big Rivers system is an inescapable fact that is deeply disturbing to us. Nearly seventy percent of Big Rivers' member revenues comes from two aluminum smelters: NSA and Alcan. This overwhelming dependence on two huge customers creates a tremendous risk for the utility. If the aluminum industry goes sour, the result for Big Rivers and its 75,000 customers will be catastrophic. When the aluminum industry entered a deep recession beginning in 1983, Big Rivers found itself in a nightmarish position. To add to its misery, the utility's remaining load growth had leveled off, the prospect of a synthetic fuels industry had evaporated, and the $900 million Wilson Unit No. 1 was nearly completed. Big Rivers was paying the price for being basically a one-industry utility.

The Commission's awareness of this problem was an important element in establishing our statewide planning docket.[28] In that docket we are examining, among other things, the long-term prospects of sharing capacity among the state's electric utilities, rather than permitting utilities to continue the traditional practice of adding new capacity based primarily on forecasts of their internal loads. That docket offers hope that Big Rivers' one-industry problem can be mitigated in the long run.

In the near term, if Big Rivers, its creditors, and customers can agree on a plan to stabilize the utility, it is incumbent on both the public and private sectors to immediately begin seeking new industries to locate in Big Rivers' territory and encouraging existing employers to expand. This is an important first step in the long and difficult process of diversifying the utility's load. But in the current climate, this step is difficult if not impossible. It is to this climate of uncertainty that we now turn.

The financial condition of the aluminum smelters is a matter of controversy in this case. Of significant importance is the

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28 Administrative Case No. 308, An Inquiry Into Kentucky's Present And Future Electric Needs And The Alternatives For Meeting Those Needs.

issue raised by Big Rivers that its proposed rates are competitive rates for aluminum smelters. The Commission ruled at the hearing that it would not consider evidence on the costs and profitability of particular smelters, although it would consider evidence on the economic conditions of the aluminum industry in general.[29] We find it difficult to evaluate the arguments and counter-arguments on this issue. An aluminum company is in a vastly different position than a regulated utility. There is no monopoly franchise and no obligation to serve. Even a relatively profitable plant can be closed if its owner decides that other considerations outweigh its continued operation. One such consideration is uncertainty about the cost of its major raw material: electricity.

It is important to note four points that have emerged from the thousands of pages of testimony in this proceeding:

- The aluminum industry has made a major investment in Western Kentucky and would like that investment to succeed.
- If the uncertainty can be lifted from the Big Rivers system and some reasonable compromise reached among all parties, then there is still hope that the aluminum industry will decide to stay, and perhaps even grow.
- If the aluminum industry leaves, the chances of the Big Rivers' creditors ever recouping their investment dramatically decline.

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29 Hearing Transcript, Volume I, page 116.

- Wilson is not a half-finished nuclear station. It is a revenue-producing, state-of-the-art coal-fired unit that may be capable in the long run of producing enough revenue as part of the Big Rivers system to repay a substantial portion or possibly all of the creditors' investment.

COMMISSION CONCLUSIONS

With this as background, the Commission has reached the following conclusions:

The overriding issue in this case is the workout plan, not a proposed rate increase. The workout plan as it now stands is filled with unrealistic assumptions and unspecified targets. The Commission is disappointed with the bargaining position taken by Big Rivers in the negotiations with its creditors. After meeting with the REA and being advised that the REA's policy was no bailouts under any circumstances,[30] Big Rivers attempted to negotiate a workout plan to insure the repayment to REA and the banks of all outstanding principal and interest. The workout plan was thus achieved by merely deferring present financial obligations to future periods and thereby committing Big Rivers' ratepayers to two projected rate increases, in 1989 and 1991, and an indeterminable number thereafter.

Rather than provide a workable solution, the plan would intensify the climate of uncertainty. The result would very likely be a severe erosion in the economic base -- including the aluminum industry -- that supports the Big Rivers system. This

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30 Hearing Transcript, Volume I, page 148.

would be a disastrous result not only for Big Rivers and its customers, but also for its creditors.

Since our approval of this rate increase would trigger the operation of the workout plan, we reject the rate increase as unreasonable. We will not be drawn inch by inch into approving so important a workout plan. In reviewing any future workout plan, we will likewise vigorously assert our statutory right and responsibility to examine and approve the complete proposal, including all assumptions and supporting data. In so doing, the Commission will seek to insure that the interests of all parties are balanced and that the interests of all classes of Big Rivers' ratepayers are preserved. There is a heavy burden of responsibility on the primary negotiators of the workout plan to incorporate those interests in a workable solution.

We are today on our own motion establishing an investigation into the reasonableness of the rates of Big Rivers. In this case we are ordering Big Rivers to conduct over the next four months a series of negotiations aimed at reaching an acceptable solution to this problem. First, Big Rivers will seek to negotiate a revised workout plan with its creditors similar to the one approved by the REA in the Sunflower Electric Cooperative case. Next, Big Rivers will begin meeting with the aluminum companies to negotiate a flexible rate plan that recognizes both the cyclical nature of the aluminum industry and the needs of the utility. The Commission is interested in the results of these negotiations even if agreement can be reached with only one aluminum company. Finally, Big Rivers is to meet with the Attorney General and other interested parties to explain the negotiations and discuss how the interests of the non-aluminum customers are being protected. We strongly urge all participants to enter these discussions promptly and in a spirit of good faith. If the participants deem it helpful, the Commission will offer its assistance in facilitating the discussions. We would hope that one outcome of these negotiations would be the settlement of all pending civil litigation.

If the participants cannot agree on an acceptable workout plan and associated flexible rate plan in the next four months, the Commission will move quickly thereafter to set just and reasonable rates for Big Rivers. The evidentiary record on which these rates will be set will include the record in this case, which will be incorporated by reference into Case No. 9885, An Investigation Of Big Rivers Electric Corporation's Rates For Wholesale Electric Service.

We do not accept NSA's contention that Big Rivers' customers are entitled to a rate decrease because the utility has commingled assets of the existing system and the Wilson system. In this case, we decline to cut the Big Rivers system in two. The Commission finds that the expenditure of funds to complete Wilson was in the discretion of Big Rivers' management. Therefore, that aspect of NSA's complaint is denied. The issue of the allocation of off-system sales remains before the Commission in its investigation of Big Rivers' rates. In the further negotiations, all the participants should focus on the potential cash flow of the entire Big Rivers system under a revised workout plan and how that will affect the fairness of rates to Big Rivers' customers.

We emphatically reject the claim of REA, the banks, and Big Rivers that the members of the cooperative ultimately bear the total risk and responsibility for the utility's debts. The distribution cooperatives and their members do not stand in the same position as shareholders of an investor-owned company. The REA, with its oversight and monitoring responsibility, bears a substantial amount of the risk associated with Big Rivers' actions. The creditor banks are compensated for the risks they take. Cooperative members must shoulder a portion of the risk, too, since they have a say in the affairs of the utility. Nor are the aluminum companies exempt from responsibility. Until the downturn of recent years, these companies or their predecessors were in frequent contact with Big Rivers' management. Rather than allocate the risk among all parties now, we have chosen to give the participants an opportunity to discuss the allocation among themselves as a revised workout plan is negotiated.

ISSUES

Commission Jurisdiction Over Workout Plan

Big Rivers has not sought Commission approval of the workout plan itself. Approval is being sought only for the proposed rates which are based on the workout plan. However, the workout plan will directly impact Big Rivers' financial stability. Since the proposed rates will produce revenues less than Big Rivers' full cost of service, they can only be found to meet the statutory criteria of fair, just, and reasonable if the workout plan itself is economically feasible and reasonable. Consequently, the Commission cannot accede to Big Rivers' request that the proposed rates be reviewed in a vacuum. The Commission concludes that Big Rivers and its creditors expect that an Order approving the proposed rates and activating the workout plan will equitably bind the Commission to all the plan's provisions. It is for these reasons that the Commission is compelled to review the economic feasibility of the workout plan at this time.

Workout Plan

Big Rivers, in an effort to resolve its financial problems, has negotiated a workout plan with its creditors. The plan, as filed on August 13, 1986, has four key elements:

1. Debt deferral.

2. Interest rate reduction.

3. Additional funds loaned by the banks to reduce high interest government debt.

4. Settlement of REA's foreclosure suit against Big Rivers.[31]

The workout plan is conditioned upon Big Rivers' submission of this rate case requesting authority to increase capacity charges to $7.50 per KW, to modify billing demand to provide for a peak demand ratchet, to restructure its debt as provided in the plan, and to limit annual capital expenditures to specified levels.[32] Additionally, the plan provides that if the Commission approves the rate proposal as submitted, the REA and the banks

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31 Schmitz Direct Prepared Testimony, page 4.

32 Big Rivers Debt Restructuring, July 21, 1986, Section A, (Revised July 29, 1986.)

will attempt to agree on future financial and other relevant targets which Big Rivers must attain.[33]

After an affirmative decision by the Commission with respect to the rate case and an agreement by the creditors on the targets, the workout plan further provides that the REA will withdraw its foreclosure action. In addition, the interest rate on Big Rivers' arrearage to the federal government ("government arrearage") will be reduced to 8 percent from a composite rate of 10.33 percent and additional debt restructuring will occur.[34] Further, the banks will loan Big Rivers $24 million.[35]

As a result of the additional debt restructuring, Big Rivers will begin paying the accrued as well as current interest on interest drawings, purchase price drawings and principal drawings associated with pollution control bonds.[36] Cash flow in excess of the amount necessary to pay operating expenses and the obligations to the banks will be used to pay interest and principal on, first, REA debt, Federal Financing Bank ("FFB") debt and then government arrearage debt. If cash flow is insufficient, REA will advance Big Rivers sufficient funds ("shortfall debt") to service the FFB debt. The shortfall debt will accrue interest at rates matching the FFB obligations and will have various maturities. The

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33 Ibid., Section C.

34 Big Rivers' Response to NSA's Second Request for Information, Item 96, page 1.

35 Schmitz Direct Prepared Testimony, pages 6-7.

36 Ibid., page 7.

government arrearage debt will convert to 30-year, 8 percent mortgage debt when cash flow is sufficient.[37] The amount due on pollution control bonds will be amortized following payment of the government arrearage debt and the unsecured arrearages.[38] Finally, neither the REA nor the banks will be obligated to proceed if Big Rivers does not meet its targets, if an affirmative rate decision is not sustained or is unfavorably modified,[39] or if the Commission does not approve the rate case as submitted.[40]

According to Big Rivers,

> The central idea behind the restructuring plan is that all of Big Rivers' cash flow beyond that needed for operating expenses and minimal capital improvements will be used to service Big Rivers' debt. In return, the creditors will defer sufficient debt to enable Big Rivers to add the D.B. Wilson plant to its system without causing "rate shock" to its customers and without increasing rates to the aluminum smelters over 1985 levels. In addition, should Big Rivers not achieve its sales targets and consequently be unable to fully meet payments scheduled in the debt restructuring plan, the creditors will further defer those amounts.[41]

Big Rivers stated in its application that the proposed rates are the initial step in the workout plan. Mr. Thorpe stated that the proposed rates are below the full cost-of-service[42] and Mr. Schmitz stated that without the workout plan demand rates would be

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37 Big Rivers Debt Restructuring, Section D(6).

38 *Ibid.*, Section D(7).

39 *Ibid.*, Section D(9).

40 *Ibid.*, Section C.

41 Schmitz Direct Prepared Testimony, page 8.

42 Thorpe Direct Prepared Testimony, page 12.

$10.75 rather than the proposed $7.50 to meet the cost-of-service.[43] Mr. Jacobs of Manufacturers Hanover and Mr. Heath of the REA submitted rebuttal testimony and presented oral testimony at the public hearing on behalf of Big Rivers in support of the workout plan.

It is the position of the intervenors that the workout plan is neither a long-range solution to Big Rivers' financial problems nor in the best interests of Big Rivers' consumers. The issues arising from the plan with which the intervenors take exception are:

1. Future financial targets.
2. Off-system sales levels.
3. Future rate increases.
4. Allocation of risk.

Future Financial Targets

Both NSA and Alcan maintain that the workout plan lacks specificity in that the plan provides that Big Rivers must attain financial targets to be determined by the creditors after a favorable Commission decision on the rate case as submitted.[44] Upon cross-examination, Mr. Thorpe testified that he had no idea whether any targets were being discussed, that he thought all the targets were included in the plan, and that he was unaware of other targets.[45]

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43 Schmitz Direct Prepared Testimony, page 9.

44 Big Rivers Debt Restructuring, Section C.

45 Hearing Transcript, Volume I, page 191.

With respect to the targets, Mr. Jacobs testified that measures of cash flow and the level of off-system sales were items to be considered, but the most important consideration was cash flow.[46] Mr. Heath testified that the concept of targets was included in the workout plan as an attempt to assure its long-term viability, recognizing that there will be changes in the future, such as the level of sales.[47]

In summary, Big Rivers and the creditors maintain that the plan recognizes the need for flexibility. The intervenors, however, maintain that since the creditors will not be obligated to proceed if Big Rivers fails to attain the unspecified targets, the workout plan lacks information sufficient for evaluation.

Off-System Sales and Future Rate Increases

In addition to future targets, the intervenors challenged the feasibility of the workout plan based upon the financial projections submitted by Big Rivers as support for the reasonableness of the plan. Those projections are contained in Item No. 281, Big Rivers' response to NSA's Second Information Request.

Sam F. Rhodes, testifying at the public hearing on behalf of NSA and Alcan, enumerated the key assumptions incorporated in Item No. 281 and described them as extremely optimistic.[48] According to the intervenors, the elements of Item No. 281 which render the

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46 Ibid., Volume IX, page 119.

47 Ibid., Volume VIII, page 159.

48 Ibid., Volume VII, page 133.

workout plan questionable are the amount of off-system sales and future revenue increases.

The amount of off-system sales incorporated in the workout plan includes continuing firm sales to MEAM and future firm sales of 200 MW to unspecified parties. Mr. Rhodes testified that, based on historical results, it is not reasonable to assume that Big Rivers can achieve the forecasted level of off-system sales.[49] In 1988 and 1991, Big Rivers has projected off-system sales of 4,947,085 MWH and 4,919,141 MWH,[50] respectively. The actual annual off-system sales for the past 4 years have averaged 2,547,947 MWH.[51] Mr. Rhodes further testified that based on his understanding of the workout plan, shortfall debt arising from Big Rivers' inability to achieve the projected off-system sales would increase to a level of from half a billion to three-quarters of a billion dollars. He stated that given the abundant supplies of electricity in the region, Big Rivers should have been conservative in projecting the amount of off-system sales.[52]

In his testimony on behalf of Big Rivers, Bernard Uffelman stated that, based on corrected financial projections, Mr. Rhodes had overstated shortfall debt by approximately $300 to $331

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49 Rhodes Prefiled Testimony, page 13.

50 Big Rivers' Response to NSA's Second Request for Information, Item No. 281, page 6.

51 Rhodes Prefiled Testimony, Schedule 10.

52 Hearing Transcript, Volume VII, page 155.

million.[53] Mr. Heath, testifying with regard to the prudency and reasonableness of the projections, stated that the assumptions were cautiously chosen and that REA believes that a sales level greater than projected could be achieved.[54] Mr. Heath further testified that REA's own projections were "representative of" the conclusions shown by Big Rivers in Item No. 281.[55] Mr. Jacobs agreed that the forecasts were reasonable and prudently made.[56]

Upon cross-examination Mr. Thorpe testified that:

> It's going to be difficult to make the $90 million something sales that we projected. Of course, a fear that we had at the time that we filed the case, we'd rather be on the high side than on the low side because the staff may increase the sales and reduce the rates. So, if we do not reach the projected sales that we have, it's going to be more of a shortfall on the part of the creditors, which they've agreed to pick up, so it's not going to affect Big Rivers' financial condition any more than it already is.[57]

Mr. Schmitz testified that Big Rivers' projections were optimistic but were made in order to avoid an argument as to the appropriate level of off-system sales.[58] Further, Mr. Heath testified that the market for power is now a buyer's market and that REA views

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53 Uffelman Rebuttal Testimony, page 9.

54 Hearing Transcript, Volume VIII, page 178.

55 Ibid., page 186.

56 Ibid., Volume IX, page 127.

57 Ibid., Volume I, pages 237-238.

58 Ibid., Volume II, page 161.

the market as being "a little more favorable" to the seller in 5 years.[59]

The intervenors further maintain that this proceeding is the first step to including all of Wilson in the rate base. In support of this position NSA and Alcan cited the fact that the cash flow projections in Item No. 281 include all Wilson operating costs and project rate increases in 1989 and 1991.[60]

Mr. Thorpe stated that if the Commission approves the rates in this case, this does not guarantee Commission approval of rate cases to be filed in the future.[61] However, Mr. Thorpe testified that if the projections are accurate Big Rivers will seek rate relief in 1989 and 1991. Further, Mr. Thorpe testified that the pro forma test year expenses include all Wilson expenses except for the amount being deferred under the workout plan.[62]

Allocation of Risk

In addition to unspecified future targets and unreasonable financial projections, the intervenors maintain that the workout plan unfairly imposes the risk of loss on the ratepayers and not on the creditors.

Mr. McCoy and Mr. Heath both testified on behalf of Big Rivers that the ratepayers, as the owners of Big Rivers, should

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59 ~~Ibid.~~, Volume IX, pages 11-12.

60 NSA's Initial Brief, pages 62-63, Hearing Transcript, pages 54-55.

61 ~~Ibid.~~, page 126.

62 ~~Ibid.~~, page 241.

pay for Wilson even if it represents excess capacity. Mr. McCoy stated that the ratepayers of a rural electric cooperative are the owners and are in a similar position to shareholders; therefore, costs cannot be shifted from one group to another.[63] Thus, according to Mr. McCoy, the used and useful standard, a method for allocating risk between shareholders and ratepayers, is not applicable in this case.[64] Mr. Heath testified that the debt related to Wilson was part of Big Rivers' "entire legitimate indebtedness" and should be repaid by the members of the cooperative.[65]

Mr. Schmitz testified that Big Rivers did not seek forgiveness of debt.[66] However, he did state that the creditors are at risk for any shortfall debt that may accrue because the Commission may not approve future rates to recover the shortfall debt as included in the financial projections.[67] Mr. Heath, when addressing the concept of targets, concurred with Mr. Schmitz regarding the extent of the creditors' risk.[68] Finally, Mr. Thorpe testified that the workout plan was not a solution benefiting the creditors which was thrust upon Big Rivers, pointing out that the creditors had agreed to defer any shortfall and

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63 Ibid., Volume III, page 68.

64 Ibid.

65 Ibid., Volume IX, pages 47-48, 83.

66 Ibid., Volume II, page 91.

67 Ibid., Volume II, page 168.

68 Ibid., Volume IX, page 77.

that the banks will make an additional loan of $24 million to Big Rivers.[69] Further, Big Rivers argues in its initial brief that the interest reduction is, in effect, a writedown of debt.[70]

The intervenors, however, maintain that all the risk has been placed on the ratepayers in that the creditors will ultimately be repaid their entire debt with interest.[71] Alcan argues in its reply brief that, "REA and creditor control over Big Rivers will be enhanced, while this Commission's ability to effectively regulate will be hamstrung by the yet-to-be-disclosed targets."[72]

Dr. Charles F. Phillips, on behalf of Commonwealth and Alumax, testified extensively with regard to the allocation of risk. Dr. Phillips pointed out that the workout plan was not a true restructuring of debt in that there was no writedown.[73] Dr. Phillips further stated that Big Rivers' ratepayers were not analogous to shareholders because if they live in a cooperative's service area they must become members of the cooperative in order to receive electric service. Finally, Dr. Phillips testified that the creditors and not the Commission were obligated to rescue a company from poor decisions.[74]

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69 Thorpe Rebuttal Testimony, pages 2-4.

70 Big Rivers' Initial Brief, page 101.

71 NSA's Initial Brief, page 60.

72 Alcan's Reply Brief, page 8.

73 Hearing Transcript, Volume VIII, page 29.

74 *Ibid.*, page 49.

Upon cross-examination, Mr. McCoy admitted that Big Rivers' ratepayers, unlike shareholders in an investor-owned utility, could not vote their stock in proportion to their economic interest[75] nor could they sell their stock if they disagreed with management decisions.[76] Although NSA and Alcan provide approximately 70 percent of Big Rivers' member revenues, each has only one vote "the same as any other customer has."[77]

Sunflower Debt Restructure Plan

During the course of this proceeding, other cooperatives with financial problems were referenced. Chief among those was Sunflower Electric Cooperative, Inc., ("Sunflower") of Hays, Kansas. A copy of Sunflower's workout plan was submitted by REA on December 19, 1986. Sunflower's plan, unlike that of Big Rivers, is not contingent upon regulatory approval of a rate increase and does incorporate the possibility of the forgiveness of principal.

~~In this case, the intervenors argued that Big Rivers should~~ have sought forgiveness of a portion of principal and maintained that a rate increase would be harmful to the ratepayers, especially the aluminum smelters. Mr. Thorpe stated that Big Rivers was informed early in the negotiations that there was no possibility of a write-off.[78] Mr. Heath stated that REA expects no write-off

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75 Ibid., Volume III, page 97.

76 Ibid., page 102.

77 Ibid., Volume VIII, page 68-69.

78 Ibid., Volume I, page 148.

under the Sunflower plan[79] and that REA does not deal in grants.[80] Big Rivers further argues that the smelters can afford this rate increase[81] and that the creditors felt the increase should be greater.[82]

The Commission is of the opinion that the speculative nature of the provisions regarding off-system sales, future rate increases, and financial targets clearly tips the balance of the present agreement in favor of the creditors. In contrast to Big Rivers' workout plan is the Sunflower plan which is not contingent upon an immediate rate increase, speculative off-system sales, or unspecified future targets. In addition, the Sunflower workout plan incorporates the possibility that debt may be written off in the future.

When cross-examined by NSA's counsel regarding the possible write-off of debt, Mr. Heath stated that there were more dissimilarities than similarities between Big Rivers and Sunflower due to Sunflower's past "efforts in rate remedies and their present rate structure."[83] The Commission cannot concur with Mr. Heath's assessment of the situation. Sunflower is a financially troubled cooperative that has attempted to remedy its problems through rate increases. Its rates are presently more than double those of Big

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79 ~~Ibid~~., Volume VIII, page 204.

80 ~~Ibid~~., Volume IX, page 53.

81 Big Rivers' Reply Brief, page 5.

82 Jacobs Rebuttal Testimony, pages 7-8.

83 Hearing Transcript, Volume VIII, pages 205-206.

Rivers.[84] Both Big Rivers and Sunflower have unique characteristics. Nevertheless there are striking similarities between the two.

Like Sunflower, the ability of Big Rivers' ratepayers to bear an increase is questionable, but for different reasons. Big Rivers is unique in that approximately 70 percent of its member revenues is derived from the aluminum industry which is in an economically depressed condition. Further, the collapse of the aluminum companies would have a devastating affect on the economy of Western Kentucky. Therefore to compare the rate levels and rate structure of Big Rivers and Sunflower is inappropriate.

The Commission is not endorsing the Sunflower plan in its entirety. The Commission, however, notes that the Sunflower plan, by not requiring immediate rate increases and not guaranteeing full recovery of debt, presents a more equitable balancing of interests. Further, the severe economic condition of the aluminum industry and Big Rivers' unique load configuration place Big Rivers in a financial position similar to that which nearly led to Sunflower's collapse.

Prudency

NSA and Alcan have raised the question of whether Big Rivers' decision to build Wilson and complete it in 1984 was prudent. Their concerns relate primarily to two points. First, Big Rivers relied heavily on a Southern Engineering Company study entitled "Power Cost Study" to determine the capacity of the planned

84 Ibid., page 204.

generating unit. Secondly, they questioned Big Rivers' decision in 1981 to continue with the construction of Wilson in light of reduced demand. In its analysis, Alcan concluded that 39 percent of the Big Rivers' Wilson investment should be excluded from rates. On the other hand, NSA determined that the entire investment should be excluded.

H. Clyde Allen, witness for Alcan, testified that the Southern Engineering study, which was the basis for the decision to build the 395 MW Wilson unit, relied on another study by Black and Veatch entitled "Report on Power Supply Reliability". The Black and Veatch study computed reserve requirements for "varying sizes of additions" to the Big Rivers system.[85] The study showed that, "based on the loads for 1985 forecast in the 1977 Power Requirements Study, (1,450 MW), if 200-MW units are added, a reserve margin of 16.4 percent would be needed and an additional 400 MW (two units) would be needed. On the other hand, if 400-MW units were to be installed, a reserve margin of 42.5 percent would be required and 780 MW (two units) would be needed."[86] Southern Engineering, using a similar reliability criterion, found that "if 200-MW units are added, a reserve of about 20 percent is appropriate, whereas if 400-MW units are added, a reserve of approximately 50 percent is appropriate."[87] The concern raised by Mr. Allen was that both studies initially show similar reliability

85 Allen's Prefiled Testimony, page 4.

86 ~~Ibid~~.

87 ~~Ibid~~., page 5.

problems with 400 MW units, yet the final plan adopted by Big Rivers called for the installation of only 400 MW units.[88] Mr. Allen testified that Southern Engineering, after evaluating several alternatives, revised its report and recommended "an expansion plan based on installing 395 MW coal-fired steam plants."[89] It is Mr. Allen's opinion that given the superiority of the expansion plan based on installing 210 MW units "from a cost standpoint, a reliability standpoint and a flexibility standpoint," he "would have rejected the consultants' recommendation."[90] Maurice Brubaker, witness for Alcan, testified that since Big Rivers was imprudent, approximately 39 percent of the Wilson investment should be excluded from rates.[91]

In response, Mr. Thorpe testified that the final decision to build the 400 MW Wilson units was not a simple one but involved a complex planning process which lasted from 1977 to 1980.[92] He further stated that during this period there were public hearings before the Commission and, in addition, REA was involved in an ongoing review of the decision making process of Big Rivers.[93]

Dr. Howard W. Pifer, III, witness for NSA, testified that Big Rivers initially relied on obsolete forecasts made in 1977 but

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88 Ibid.

89 Ibid., page 9.

90 Ibid.

91 Brubaker's Prefiled Testimony, pages 11 and 12.

92 Thorpe Rebuttal Testimony, page 14.

93 Ibid.

then changed its emphasis to industrial demand after experiencing rapid erosion of its rural demand in early 1980. This included 95 MW for a fourth potline to be added by ARCO (predecessor of Alcan) but not yet under contractual agreement, 110 MW in synthetic fuels load in 1985, plus an unidentified potential load of 180 MW in 1985 for a total of 385 MW. Dr. Pifer concluded that such reliance on potentially large but uncommitted industrial loads was imprudent.[94] Dr. Pifer's analysis led him to conclude that all of Big Rivers' Wilson investment should be excluded from rates.

Mr. Thorpe testified that while the 1980 Power Requirements Study did include the expansion by ARCO, it did not contain any allowances for the synthetic fuel loads. He further stated that in 1981 if the largest unit was off-line, the combustion turbine was running, and 40 MW of SEPA power was purchased, the system could serve a load of 1126 MW.[95] He stated that this would have been about 45 MW short of the expected load of 1170 MW in 1984, when Jackson Purchase Electric Cooperative was to be added to the system and about 200 MW short of that needed in 1987 with the ARCO expansion.[96] These factors led Big Rivers to continue with the construction of the Wilson plant.

The Commission concludes that the evidence in this case does not clearly demonstrate that Big Rivers was imprudent in building

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94 Pifer Supplemental Prefiled Testimony on Prudence Issues, pages 43, 45, and 48.

95 Southeastern Power Administration.

96 Thorpe Rebuttal Testimony, pages 21-22.

Wilson. Like many utilities around the country, Big Rivers experienced an unanticipated flattening of its load growth. Coupled with that was a drastic decline in the fortunes of its major customers, the aluminum companies. Although the outcome of Big Rivers' decisions on Wilson has been difficult, the decisions themselves under the circumstances at the times they were made cannot be said to be clearly imprudent.

Used and Useful

A major issue in this rate case is whether the capacity of Wilson is needed on the Big Rivers system. The issue of the need for Wilson has been extensively addressed by all parties on both an engineering and economic basis. Basically, the intervenors' position is that the Commission is bound to employ the used and useful standard to determine whether the Wilson facilities are needed on Big Rivers' system and should be included in rate base for rate-making purposes. On the other hand, Big Rivers argues that undue reliance should not be placed on the used and useful standard because the Commission is obligated by statute to establish rates that are fair, just, and reasonable. The Commission is of the opinion that it is under no statutory obligation to apply a used and useful standard exclusively, or any other single, rigid standard.

KRS 278.290(1) provides that:

> [T]he commission may ascertain and fix the value of the whole or any part of the property of any utility in so far as the value is material to the exercise of the jurisdiction of the commission, and may make revaluations from time to time and ascertain the value of all new construction, extensions and additions to the property of the utility.

In determining the value of a utility's property, this statute grants the Commission significantly more latitude than is available to those commissions that are constrained by a statutorily mandated used and useful criteria. The establishment of fair, just, and reasonable rates involves a balancing of utility and ratepayer interests. After balancing these interests, the Commission may conclude in a given case that rates should be based upon prudent investments even where facilities are cancelled prior to completion of construction. On the other hand, in considering the need for facilities on an economic basis, the Commission may decide that it is not in the customers' interest to pay rates that include the cost of unneeded facilities.

The controlling statutory standard for the establishment of utility rates is set forth in KRS 278.030(1): "Every utility may demand, collect and receive fair, just and reasonable rates for the services rendered or to be rendered by it to any person." A relevant Kentucky decision on valuing utility facilities is Fern Lake Co. v. Public Service Commission, Ky., 357 S.W.2d 701 (1962).

In Fern Lake, the Commission refused to permit a water utility, Kentucky Water Service Co., to increase the booked original cost of its water facilities despite its claim that the facilities had been intentionally undervalued as a convenience and conservative accounting practice. The Commission upheld the use of the book value on finding that the water facilities were substantially in excess of that needed to render service and, consequently, the lower book value accounted for this excess.

In affirming the Commission's decision, the Kentucky Court of Appeals held that:

> [T]here was also evidence that since this water system was designed to serve an expected population far greater than the number of customers it has ever had, its facilities are far in excess of those needed; and hence the excess facilities are not used or useful so as to be a proper factor in establishing a rate base.... Furthermore, as a matter of law, we believe the Commission properly refused to include the cost of over-adequate facilities in the rate base. Fern Lake at 704-705.

Of significant note is the Court's statement that "the excess facilities are not used or useful." (Emphasis added.) While this language has led Big Rivers to argue that facilities can only be excluded from rate base if found to be neither used nor useful, such an argument is inconsistent with the totality of the Court's decision to focus on the adequacy and need for facilities.

In determining the need for facilities, such as an electric generating plant, the Commission must consider not only whether it is used and useful, but also the need for improved reliability, the system's load characteristics, the potential for growth of both system load and load factor, and other relevant economic and engineering factors. In establishing rates that are fair, just, and reasonable, the Commission must (1) determine the appropriate level of operating expenses; (2) fix a value on the utility's property; and (3) establish a rate of return for the rate base to produce a fair return on the investment of an investor-owned utility or establish a times interest earned ratio to allow the payment of interest and principle by a cooperative utility. The rate of return/times interest earned ratio is directly related to the rate base determined. As the Court stated in Commonwealth ex re. Hancock v. South Central Bell, Ky., 528 S.W.2d 659, 662, (1975), "[T]he reasonableness of the rate of return cannot be decided in isolation from the rate base to which the rate of return will be applied, because the reasonableness of the rate of return will vary in accordance with the method or formula employed in fixing the rate base." (Emphasis in original.)

Rate base and debt service coverage for a cooperative utility must be determined by applying the same standards applicable to investor-owned utilities. Cooperatives, organized under KRS Chapter 279, "shall be subject to the general supervision of the Energy Regulatory Commission [predecessor of the Public Service Commission] and shall be subject to all the provisions of KRS 278.010 to 278.410(1)." KRS 279.210(1). A cooperative's system is defined as consisting of "any plant, works, facilities and properties...used or useful in the generation, production, transmission or distribution of electric energy." KRS 279.010(8). In balancing the equities to determine just and reasonable rates, the used and useful standard must be applied to cooperatives in the same manner as it is applied to investor-owned utilities.

In examining the results of the negotiations on a revised workout plan, the Commission will be guided by an evaluation of what is fair, just, and reasonable for Big Rivers, its customers, and its creditors. We do not believe that the statutes or the court in Fern Lake have shackled us to a mechanical application of the used and useful standard. We must carry out a complex balancing of equities and allocation of risk.

Reliability

The extensive debate over whether the Wilson unit is essential to the reliability of the Big Rivers' system starkly illustrates the fact that this case involves considerations other than a mechanical application of the used and useful test. We do not at this point have to accept the simple chain of logic presented by the parties which would follow from a determination with respect to reliability. Rather, the Commission is seeking a solution that would fairly balance the interests of all parties. Since we have found the proposed workout plan unreasonable and unacceptable, we have not had to settle the argument over the parameters of reliability. However, the issue of reliability as it relates to the used and useful concept remains before the Commission in its investigation of Big Rivers' rates. Thus, if the participants do not arrive at an acceptable agreement, the Commission will further evaluate the evidence on this issue.

Certificate of Convenience and Necessity

The Commission granted Big Rivers a certificate of convenience and necessity to construct Wilson on June 17, 1980, in Case No. 7557. Relying on that certificate, Big Rivers moved to strike portions of the testimony filed by NSA and Alcan on the grounds that the testimony was a collateral attack on the certificate. NSA and Alcan responded by stating that the testimony was not offered for purposes of rehearing or revoking the certificate but to address Big Rivers' prudency in planning and constructing the Wilson facilities. These prudency issues relate to whether Wilson should now be included in rate base. By

Order entered November 25, 1986, the Commission denied the motion to strike based on the findings that testimony addressing Big Rivers' prudency in planning and construction of Wilson was highly relevant to the fundamental issue of whether Wilson should be included in Big Rivers' rate base.

Big Rivers has continued to argue that the Commission's issuance in 1980 of a certificate to construct Wilson now bars any prudency review of Big Rivers' planning and construction decisions prior to 1980. The Commission does not intend to revoke the certificate in this rate case. In carrying out its statutory duty to value Big Rivers' property for rate-making purposes, the Commission must review and weigh all evidence surrounding Big Rivers' decision to construct Wilson.

Other Issues

Testimony and evidence which suggested that Big Rivers should give serious consideration to the option of filing bankruptcy to alleviate its financial problems was presented to the Commission. The Commission does not see bankruptcy as a preferable option for Big Rivers. Bankruptcy would prolong the corrosive uncertainty in the Big Rivers service territory. It could prove unfortunate for both customers and creditors.

Considerable evidence and testimony was presented concerning the proposed rate design in this case. The controversial point was the application of a ratchet demand provision in Big Rivers' tariff. Since no increase in revenue has been granted in this case, there is no reason to modify Big Rivers' tariffs at this time. However, this issue remains before the Commission in its further investigation of Big Rivers' rates.

FURTHER PROCEEDINGS

The Commission is of the opinion that the serious financial problems now facing Big Rivers must be resolved quickly. The fate of Big Rivers, the aluminum smelters, and the economy of Western Kentucky cannot be left in doubt. The gravity of this situation demands that extraordinary steps be taken by the Commission to effectuate a fair solution.

Based on the decision herein to reject the workout plan and require Big Rivers to renegotiate with its creditors, the Commission will initiate a further proceeding to review the revised workout plan to be submitted pursuant to the provisions of this Order. A docket will be established for this purpose simultaneously with the issuance of this Order. In that docket the Commission will have before it all the issues in this case but not finally decided. We will consider these issues in the context of a revised workout plan, or, in the event an acceptable revision is not submitted, the Commission will make definitive determinations with respect to these issues.

Also to be considered will be the flexible power rates to be negotiated by Big Rivers with NSA and Alcan. The parties need to be aware during this negotiating process that should they be unable to resolve the rate issues surrounding Wilson and the smelters' economic viability, the Commission will move rapidly in the new docket to adjudicate those issues and establish fair, just, and reasonable rates for Big Rivers.

The Commission recognizes that the prior negotiations between Big Rivers and its creditors were protracted. However, there must now be an intensive effort among all participants to work together and expend their best efforts. The negotiations must proceed expeditiously, and the Commission will be available to assist in the process.

The Order initiating the new proceeding will provide that:

1. A revised workout plan and flexible power rates for NSA and Alcan should be submitted no later than July 17, 1987;

2. A hearing will be held on July 28, 1987, for the purpose of receiving testimony and cross-examination concerning the revised workout plan and the flexible rates;

3. The record of evidence in this rate case will be incorporated by reference in the new docket and all parties in the rate case will be designated parties therein.

GUIDELINES FOR REVISED WORKOUT PLAN

The Big Rivers power system is a valuable resource to the citizens of Western Kentucky and the Commission is looking for a reasonable, workable, long-term solution to Big Rivers' problems. In this Order the Commission has asserted its statutory right to review and approve a revised workout plan. The overall goal of the revised workout plan should be to stabilize the Big Rivers service area and provide for economic growth to diversify Big Rivers' load. The plan must offer an equitable balance among all interests. Any acceptable revised workout plan must seriously consider the following guidelines.

1. It is the opinion of the Commission that a good starting point for negotiation is the Sunflower Electric Cooperative Debt Restructure Plan. Recognizing the disturbing lack of load diversity and Big Rivers' dependence upon a sluggish aluminum industry, provisions similar to the Sunflower Plan which are not contingent upon an immediate rate increase and guaranteed full repayment of debt are desirable.

2. The immediate and primary source for debt service is off-system sales. Therefore, an agreement on off-system sales should be used in calculating any schedule of debt repayment. Big Rivers' ratepayers should not have unlimited responsibility for the payment of Big Rivers' debt. Furthermore, they should not be required to provide all the revenues required to offset shortfalls arising from insufficient off-system sales.

3. The interests of all affected parties must be considered: rural consumers, industrial customers and creditors. Big Rivers should meet with the creditors to negotiate a revised workout plan. Big Rivers and the aluminum companies should negotiate a flexible rate plan that recognizes the cyclical nature of the industry and the revenue requirements of the utility. Big Rivers, the Attorney General, and other interested parties should meet to discuss the negotiation and determine how the interests of customers other than NSA and Alcan can best be protected.

4. While the Commission expects and the public interest requires that all participants negotiate expeditiously and in good faith, the Commission will make the ultimate decision as to a reasonable long-term solution and no participant will have a veto.

The Commission wishes to see the results of negotiations within the time frame established herein.

5. The payment of Big Rivers' obligations to its creditors should take into consideration longer terms, reduced interest rates, deferral of principal and interest payments, preferred stock options, payments tied to off-system sales, and reduction of principal.

6. Consideration should be given to sale or disposal of Wilson to another entity or through establishment of a generating subsidiary as a possible long-term solution.

7. The plan should include well documented projections of system and off-system sales and cash flow over both the short and long term. Documentation should include a thorough explanation of all assumptions, reasonable specificity of targets, and detailed work papers supporting the long and short run cash flow projections.

8. A revised workout plan must contain much more affirmative support by REA of Big Rivers' efforts to achieve off-system sales. The current workout plan states only that "the REA will not unreasonably withhold its consent to power sales agreements proposed by BREC [Big Rivers] or to "non-disturbance" provisions with power purchasers in appropriate cases."

9. Priority of disbursements with regard to principal and interest should be clearly established.

10. Big Rivers is currently involved in litigation with REA and the Justice Department, Alcan, and NSA. The revised workout plan should include a settlement of all outstanding litigation.

SUMMARY OF FINDINGS

Based on the evidence of record and being advised, the Commission is of the opinion and hereby finds that:

1. The workout plan has a direct and immediate impact on Big Rivers' financial stability, thus rendering the workout plan subject to the jurisdiction of the Commission.

2. The workout plan will not provide for a workable, long-term solution to Big Rivers' financial problems and the workout plan should be denied.

3. The rates proposed by Big Rivers pursuant to the workout plan are unfair, unjust, and unreasonable and should be denied.

4. Big Rivers' expenditure of funds to complete Wilson was within management's discretion and that aspect of NSA's complaint should be denied. The issue of the allocation of off-system sales remains before the Commission in its investigation of Big Rivers' rates.

5. The Commission's 1980 Order in Case No. 7557 granting Big Rivers a certificate of convenience and necessity to construct the D.B. Wilson Generating Station does not estop the Commission, in a rate-making proceeding, from reviewing all issues surrounding Big Rivers' prudency in planning and constructing Wilson and deciding if Wilson should be included in rate base.

6. The evidence of record is insufficient to support any findings that Big Rivers was clearly imprudent in its decision to build Wilson and complete it in 1984.

7. Big Rivers should negotiate a revised workout plan with its creditors and negotiate flexible power rate schedules with NSA

and Alcan in accordance with the guidelines set forth in this Order. Big Rivers should discuss with the Attorney General and other interested parties how the interests of customers other than NSA and Alcan can best be protected.

8. A further proceeding should be initiated immediately to review the reasonableness of Big Rivers wholesale power rates and the results of Big Rivers' negotiations with its creditors and with NSA and Alcan. All issues not finally decided herein will be before the Commission in the further proceeding; the evidence of record herein should be incorporated by reference in the further proceeding; and all parties herein should be designated as parties in the further proceeding.

ORDERS

IT IS THEREFORE ORDERED that:

1. The rates proposed by Big Rivers be and they hereby are denied and Big Rivers shall continue to charge the rates set forth in its existing tariffs until further Order of the Commission.

2. The aspect of NSA's complaint alleging the diversion of funds for the completion of Wilson be and it hereby is denied.

3. Big Rivers' workout plan be and it hereby is rejected.

4. Big Rivers shall negotiate a revised workout plan with its creditors and negotiate flexible power rate schedules with NSA and Alcan in accordance with the guidelines set forth in this Order.

5. An investigative proceeding shall be initiated for the purposes set forth in Finding No. 8, above.

Done at Frankfort, Kentucky, this 17th day of March, 1987.

By the Commission

ATTEST:

Forest M. Skaggs

Executive Director

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC	)	
CORPORATION FOR A GENERAL	)	Case No.
ADJUSTMENT IN RATES	)	2012-00535

DIRECT TESTIMONY

OF

BION C. OSTRANDER

PUBLIC REDACTED VERSION

ON BEHALF OF

KENTUCKY OFFICE OF ATTORNEY GENERAL

FILED: May 24, 2013

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BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2012-00535

DIRECT TESTIMONY OF

BION C. OSTRANDER

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1. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Bion C. Ostrander. My business address is 1121 S.W. Chetopa Trail, Topeka, KS 66615-1408.

Q. WHAT IS YOUR OCCUPATION?

A. I am President of Ostrander Consulting. I am an independent regulatory consultant and a Certified Public Accountant ("CPA") with a permit to practice in Kansas.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of the Kentucky Office of the Attorney General ("OAG") in this rate case proceeding regarding Big Rivers Electric Corporation ("BREC") request for substantial rate relief.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE AND EDUCATIONAL BACKGOUND.

A. Please see Exhibit BCO-1 for more information regarding my professional experience and educational background. In summary, I am an independent regulatory consultant and a practicing CPA with a specialization in regulatory issues. I have over thirty-three years of regulatory and accounting experience. I have addressed many regulatory issues in numerous state jurisdictions and on an international basis.

I started my consulting practice in 1990, Ostrander Consulting, after leaving the Kansas Corporation Commission ("KCC"). I previously served as the Chief of Telecommunications for the KCC from 1986 to 1990, and was the lead witness on most major issues. I served as Chief Auditor for the KCC from 1983 to 1986, addressing issues regarding telecom, gas, electric, and transportation. In addition, I have worked for international and regional accounting firms, including Deloitte, Haskin and Sells (now Deloitte).

I received a Bachelor of Science degree in Business Administration with a major in Accounting from the University of Kansas in 1978. I am a member of the American Institute of CPAs ("AICPA") and the Kansas Society of CPAs ("KSCPA").

Q. WHAT TYPE OF REGULATORY ISSUES HAVE YOU ADDRESSED?

A. I have addressed many regulatory issues in my career. My experience includes addressing issues related to rate cases under rate of return ("ROR") regulation and TIER requirements, alternative regulation/price cap plans, management audits, specialized accounting and regulatory issues, and other matters.

I have addressed a broad range of issues in my career, including retail and wholesale cost studies, competition, affordable rates/universal service, service quality, infrastructure/modernization, specialized accounting matters, affiliate transactions, income taxes, sale/leaseback, compensation, cross-subsidization, depreciation, rate design, sales/acquisitions and many other matters.

During my tenure at the KCC, I addressed major regulatory issues in the energy and telecom field, including the substantive transition in the telecom industry ranging from the break-up of AT&T and the related introduction of long distance competition, the transition from rate of return regulation to alternative/incentive regulation, the proliferation of alternative carriers, the introduction of the Kansas Relay Service (for speech and hearing impaired persons), and the expansion of services and technology.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION ("COMMISSION") OR ANY OTHER UTILITY REGULATORY COMMISSION?

A. I have not testified before the Commission, but I have testified in numerous other jurisdictions and this information is provided at Exhibit BCO-1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The primary purpose of my testimony is to address adjustments to BREC's rate application and sponsor the overall revenue requirement/surplus based on an interest coverage approach instead of a traditional rate-of-return ("ROR") on rate base approach. I will also address the problems with the fully forecasted test period BREC chose in this case.

In addition, both Mr. Brevitz and Mr. Holloway will also address some issues related to adjustments, although I will incorporate all adjustment amounts in the revenue requirement calculations at Exhibit BCO-2.

In summary, I will address the following issues:

1) Overall revenue requirement/surplus using an interest coverage approach.

2) Individual rate case adjustments.

3) The problems with using BREC's forecasted test period.

4) The proper interest coverage approach to use in this rate case, Margins for Interest Ratio "MFIR" versus Times Interest Earned Ratio "TIER."

5) Propose certain policies to track and monitor BREC's capital and operating expenditures so that any excessive recovery of forecasted costs in this proceeding are not used to subsequently spend down to MFIR/TIER levels via unreasonable, excessive, extravagant, and/or imprudent spending which could, for example, cause further deferral of maintenance, and/or unduly enhance salaries.

Q. CAN YOU SUMMARIZE THE TYPE OF EXHIBITS THAT YOU ARE SPONSORING?

A. Yes, I am sponsoring three types of Exhibits:

1) Exhibit BCO-1 is my curriculum vitae.

2) Exhibit BCO-2, Schedule A-1 summarizes OAG's proposed adjustments and TIER-related revenue requirement/surplus calculation (compared to the revenue requirement of BREC), along with related supporting schedules showing the detailed adjustments as appropriate.

3) Various other exhibits - These various exhibits include documents that support my testimony, including BREC's responses to the data requests of various intervenors in this proceeding.

Q. WILL YOU SUMMARIZE YOUR TESTIMONY?

A. BREC's original application shows a revenue requirement of $74.5 million using a TIER of 1.24, and OAG's adjustments result in a revenue surplus (excess earnings) of $4,417,270, using an MFIR of 1.10.[1] Although OAG's calculations show a revenue surplus of $4,417,270, OAG is not recommending a rate reduction or refund of this amount but instead is recommending no change in rates for BREC's customers.

The OAG also provides an alternative interest coverage calculation for <u>information purposes only</u> which shows that BREC has a revenue

[1] Exhibit BCO-2, Schedule A-1, Column D, lines 33 and 34.

requirement of $2,039,500 if BREC's recommended 1.24 TIER[2] is used in the OAG revenue requirement calculations, although OAG continues to support the use of the 1.10 MFIR.

The total impact of OAG recommended adjustments increases operating income and net margins by an amount of $72,048,665.[3] Mr. Brevitz is sponsoring Adjustment OAG-1-DB which increases operating income and net margins by an amount of $63,028,536,[4] and I am sponsoring the remaining adjustments, Adjustment OAG-2-BCO through OAG-6-BCO, which increase operating income and net margins by an amount of $9,020,129.[5]

Q. DID YOU USE AN INTEREST COVERAGE APPROACH FOR CALCULATING THE REVENUE REQUIREMENT/SURPLUS IN THIS CASE?

A. Yes. I used an interest coverage approach (instead of a traditional ROR on rate base approach), and this is the same approach used by the Company, and as I understand the same approach which the Kentucky Public

[2] Exhibit BCO-2, Schedule A-1, Column D, lines 29 and 30.
[3] Exhibit BCO-2, Schedule A-1, Column G, line 33.
[4] Exhibit BCO-2, Schedule A-1, Column G, line 34.
[5] Exhibit BCO-2, Schedule A-1, Column G, line 35.

Service Commission utilizes. My exhibits will show the revenue requirement calculated using both the MFIR and TIER approach, although I am supporting the MFIR.

Q. WHAT ARE THE DIFFERENT TYPES OF INTEREST COVERAGE RATIOS THAT ARE RELEVANT TO THIS PROCEEDING, AND WHAT IS BREC RECOMMENDING?

A. I will address both the TIER and the MFIR. Big Rivers is requesting a minimum TIER of 1.24, and BREC's revenue requirement is calculated using a "Contract TIER" of 1.24. The Contract TIER of 1.24 is required by BREC's agreements ("Smelter Contracts") with its two aluminum smelters, Century Aluminum of Kentucky General Partnership ("Century") and Alcan Primary Products Corporation ("Alcan"). The Commission's November 17, 2011 Order in the prior BREC rate case (Case No. 2011-00036) accepted the use of a 1.24 Contract Tier.[6]

TIER is a measurement of a company's ability to pay its interest expense on long-term debt with its net margins. TIER is typically calculated as:

(Net Margins + Interest Expense on Long-Term Debt)/Interest Expense on Long-Term Debt.

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[6] See Order dated November 17, 2011 in Case No. 2011-00036, p. 24.

However, the calculation of Contract TIER that is used by BREC is slightly different because it requires the removal of interest income on the Transition Reserve in the calculation of net margins, and the removal of interest income is required by the Smelter Contracts at Section 4.7.5(f).

In addition, any net margins in excess of the 1.24 Contract TIER are subject to being returned first to the Smelters through the TIER Adjustment Charge (until the TIER Adjustment charge is $0), and then to the BREC non-smelter rate classes (i.e., the Rural Delivery Service and Large Industrial Class) and also the Smelters through a rebate which is subject to approval of BREC's Board of Directors and the Commission.

In addition to the Contract TIER of 1.24, BREC must meet a minimum requirement of 1.10 MFIR under BREC credit agreements. The MFIR is calculated as:

(Net Margins + Interest Expense on Long-Term Debt + Income Tax)/Interest Expense on Long-Term Debt).

For purposes of this case, the calculation of the Contract TIER and MFIR are very similar, because BREC does not pay any state or federal income taxes due to significant Net Operating Losses ("NOLs") and so these taxes are not included in BREC's revenue requirement in this rate case. Because state and federal income taxes are $0, there are not any income tax expense amounts to include in the MFIR calculation. So the only difference between the Contract TIER and the MFIR calculation for this rate case, is the Contract TIER calculation first removes interest income on the Transition Reserve from the calculation of the net margin (and the MFIR does not remove this interest income on the Transition Reserve from the calculation of the net margin).

Q. DO YOU RECOMMEND THE 1.10 MFIR IN CALCULATING YOUR REVENUE REQUIREMENT/SURPLUS?

A. Yes. I used the 1.10 MFIR in calculating the OAG's revenue requirement/surplus. I relied on the 1.10 MFIR because both Smelters have given termination notification to BREC, Century filed its notice that it will terminate on August 20, 2013 and Alcan filed its notice that it will terminate about February 1, 2014 (this later date also falls within the parameters of the fully forecasted test year used in this case). The termination will mean that the 1.24 Contract TIER required by the Smelter Contracts will be void and will not be a requirement. Because both of these Smelter terminations will take place before the end of BREC's forecasted test period ending August 31, 2014, it is reasonable to reflect the impact of these "known and measurable" termination dates in the calculation of the revenue requirements in this case. It is not necessary to use the 1.24 Contract TIER in the revenue requirement calculations, therefore I am relying on the 1.10 MFIR in the OAG's revenue requirement/surplus calculation.

Q. WAS THERE SOME INITIAL CONCERN THAT BREC'S AUDITORS WOULD ISSUE A GOING CONCERN DECISION FOR THE 2012 FINANCIAL STATEMENTS?

A. Yes. However, the Independent Auditor's Report for the 2012 financial statements is now available from BREC's auditors, KPMG, and there is no mention of a going concern issue. These 2012 audited financial statements just became available with BREC's April 19, 2013, first update to OAG 2-39. The audited financial statements were made available about two weeks later than what is typical for BREC's financial statements in the past. Also, it is somewhat unusual that the Independent Auditor's Report does not have an issuance date (or is not dated), because this is normally required. It is not completely clear if this issuance date has been redacted from the version of the Independent Auditor's Report provided to OAG, and what specific purpose that serves. I will not address the implications of a going concern statement at this time because the Independent Auditor's Report does not raise this issue.

Q. DID BREC USE A FULLY FORECASTED TEST PERIOD?

A. Yes. BREC used a fully forecasted test period for the twelve month period September 1, 2013 through August 31, 2014, and this corresponds to the first 12 consecutive calendar months the proposed increase would be in effect after the maximum 6-months. BREC also uses a base period for the 12 months ending April 30, 2013, which includes six months of actual historical data and six months of estimated data. Although BREC's forecasted test period filing appears to be technically compliant with Kentucky statutes, I have significant concerns with this forecasted filing regarding its underlying documentation, methodology, and specific impacts on costs (and this specific level of detail is not addressed in state statutes).

Q. WAS BREC'S FULLY FORECASTED TEST PERIOD SELECTED BASED ON THE TERMINATION OF THE CENTURY SMELTER CONTRACT?

A. Yes, Mr. Wolfram states that the fully forecasted test period was selected because it is the first full twelve months following the termination of the Century smelter contracts at August 20, 2013. In addition, Alcan's termination of notice came after the filing of this rate case and termination is effective February 1, 2014, which is also within the forecasted test period ending August 31, 2014.

Q. MR. WOLFRAM CLAIMS THAT THE USE OF A FULLY FORECASTED TEST PERIOD IS JUSTIFIED BY THE LOSS OF CENTURY, DO YOU AGREE?

A. No, I do not agree. BREC could have used a historic test period, removed the "actual" costs of Century, and made certain known and measurable adjustments (including other adjustments that would be affected by the loss of Century) which would have been less speculative, more accurate, reasonable, and consistent with supporting fair, just and reasonable rates. It was not necessary to file a fully forecasted test period to reflect the loss of Century, although this appears to be the primary reason used by BREC to support its fully forecasted test period.

Q. ARE YOU USING BREC'S FULLY FORECASTED TEST PERIOD ENDING AUGUST 31, 2014 AS THE STARTING POINT FOR ADJUSTMENTS IN THIS CASE?

A. Although I don't agree with BREC's use of a fully forecasted test period, the OAG has no other reasonable alternative but to use this same forecasted data as the starting point for adjustments. It would be almost impossible, and certainly impractical, for OAG to attempt to put its own rate case together based on the most recent historical test period. To attempt to put together a completely different rate case filing based on twelve months of historical data would be extremely time consuming, costly, create further confusion and problems for the Commission, and would require that the OAG have virtually the same access as BREC has to its financial records, operational records, and all other studies and analysis that might affect issues in this case. It would be necessary to have this type of information to be on the same equal footing of BREC in preparing an alternative rate case using historical data. Clearly these conditions are not going to happen, so the OAG will use BREC's forecasted test period as the starting point for adjustments.

Q. ARE YOUR APPROACH AND ADJUSTMENTS IN THIS RATE CASE INTENDED TO MAKE BREC'S RATE CASE FILING LESS SPECULATIVE, MORE TRANSPARENT, AND MORE CONSISTENT WITH THE KNOWN AND MEASURABLE PRINCIPLE?

A. Yes, from the perspective that we are removing certain adjustments of BREC that are forecasted, speculative, and are not known and measurable.

In fact, BREC used the historic test period ending October 31, 2010, in its prior rate case, and the Commission's Order recognized the "known and measurable principle" as part of that process and stated, "In using a historic test period, the Commission has given full consideration to appropriate known and measurable changes."[7]

When there are unique and substantive flaws with a filing such as BREC's, then it is best to rely upon more traditional rate-making principles typically used in an actual historic test period filing (or a forecasted filing

[7] *In the Matter of: Application of Big Rivers Electric Corporation for a General Adjustment in Rates*, Case No. 2011-00036, November 17, 2011 Order, p. 4.

that is trued-up to actual amounts during the review process), and which incorporate the guiding principles of "known and measurable", "used and useful" and the "matching principle."

Q. WOULD BREC ACKNOWLEDGE OR IDENTIFY AMOUNTS AND ADJUSTMENTS THAT "ARE KNOWN AND MEASURABLE" VERSUS THOSE THAT "ARE NOT KNOWN AND MEASURABLE"?

A. No. OAG 1-65 asked BREC to identify all amounts and adjustments in the forecasted test period ending August 31, 2014, that the Company "considers to be known and measurable" and identify all amounts and adjustments that "are not known and measurable", and to provide BREC's definition of known and measurable. BREC's response objected to the data request, but then responded that "known and measurable" standards are not applicable to a forecasted test period, so BREC will not define the phrase or distinguish the amounts in its filing between known and measurable and those which are not known and measurable.

This simple request and the absence of a reasonable response appears to be a clear roadblock intended to impede an objective evaluation of BREC's filing. Clearly, when the Company cannot, or will not, identify adjustments that are known and measurable versus adjustments that are forecasted and may be highly speculative, this causes substantive concerns.

Q. DO YOU BELIEVE THAT "FAIR, JUST AND REASONABLE RATES" (THAT ARE REQUIRED BY STATE STATUTE) CAN BE ACHIEVED VIA BREC'S FULLY FORECASTED REVENUE REQUIREMENT?

A. No, I do not believe that fair, just and reasonable rates are achievable or even a priority goal under BREC's fully forecasted revenue requirement. I will address the numerous problems with BREC's fully forecasted test period and the related revenue requirement.

Q. A FULLY FORECASTED TEST PERIOD CAN PRESENT CHALLENGES, BUT CAN YOU EXPLAIN THE UNIQUE AND SUBSTANTIVE PROBLEMS WITH BREC'S FULLY FORECASTED FILING?

A. Yes. It is not unusual for a fully forecasted test period or model to start with actual costs as a reasonable starting point for projections. However, what sets BREC apart is that the Company is unwilling to provide some of this important underlying "actual" data to support its model's outputs. Actual historical data is usually some of the best available and objective data to evaluate the reasonableness of at least the starting point for forecasted costs and related assumptions. The credibility of BREC's financial model suffers when transparency is sacrificed.

In this rate case, BREC has refused to provide certain historical data which could be used to test the transparency and accuracy of BREC's forecasted costs. Several critical examples of BREC's failure to provide important and significant underlying actual costs in this proceeding include the following:

a) **Century Smelter** - BREC would not provide the "actual" impacts for the termination of the Century Smelter, but would only use its subjective forecasted amounts. Mr. Brevitz is the primary witness for the Smelter issue and addresses OAG's adjustment in his testimony, and my testimony on this matter is limited to BREC's failure to provide actual data.

b) **Significant Pay Increases Awarded During and After the Commission's Decision in the Unwind Case and the Subsequent Retention Bonus** - These amounts are important, and these significant pay increases awarded after the Unwind Case caused ***permanent increases*** in Officer and Management pay levels that continue today and are included in the forecasted test period. However, BREC will not provide the historic information to determine how much of the significant pay increases are reflected in forecasted amounts in this case. I am addressing this adjustment later in this testimony.

Other unique and substantive problems with BREC's fully forecasted test period include the following:

1) BREC's filing does not identify or address typical "rate case adjustments" because many of these adjustments related to normalization, annualization, and related to specific changes or events are buried in the forecasting assumptions so these changes and their underlying assumptions and calculations are not readily identifiable.

2) BREC's Financial Model for forecasting does not include a "Manual" that explains the model, how it works, inputs, sensitivity, specific fields to be used for changing assumptions, assumption and input sources, and various other important data. Most reputable and credible models of any type have a supporting Manual, because this helps insure objectivity by ensuring that all parties know how the model works and operates so that the model owner cannot manipulate or change how the model operates from year to year. A Manual serves as an internal control document and provides a proper audit trail.

3) BREC's Financial Model uses input from the production cost model and the Company's budgeting system Hyperion. BREC indicates that its Financial Model cannot incorporate a sensitivity run using actual 2012 calendar year amounts.[8] First, BREC's budgeting process is not always accurate, and it is not unusual for there to be significant differences between budget amounts and subsequent actual amounts in the variance reports. If the Financial Model relies on the budgeting process, this could result in problems with outputs and the related revenue requirement calculation. Second, if the Model does not accept 2012 calendar year inputs as a sensitivity run, this could either be a system design flaw or an intentional design to avoid the most rigorous sensitivity test of the Model. It would appear that incorporating actual data into the Model would be one of the best sensitivity tests regarding accuracy and the variation of outputs based on actual inputs.

[8] BREC response to AG 2-51.

Q. CAN YOU PROVIDE EXAMPLES OF THE INACCURACY OF BREC'S BUDGETING PROCESS, WHICH IS APPARENTLY RELIED UPON IN THE COMPANY'S FINANCIAL MODEL FOR CALCULATING REVENUE REQUIREMENTS?

A. Yes. I could provide numerous examples, but I will limit this to the following two examples where in one example the Company's budget significantly overstated Net Margins 70% and in the other example the budgeting process significantly understated Net Margins:

1) Recent January 2013 Financial Budget Variance Report - For January 2013, the Budgeted Net Margin was $3,907,000, but the Actual Net Margin was $2,302,000, a difference of $1,605,000.[9] This means that BREC's budget missed the mark or overstated Net Margins by 70%. The actual results are a significant deviation from budget. This is an example of BREC's budgeting process being too positive and overstating Net Margins.

2) December 2012 YTD Financial Budget Variance Report - For the entire year of 2012, the Budgeted Net Margin was **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL.**[10] This means that BREC's budget missed the mark or understated Net Margins by **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL**. The actual results are a significant deviation from budget. This is an example of BREC's budgeting process being too negative and understating Net Margins. It might be more understandable to miss the mark on a budget for a

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[9] The December 2012 and January 2013 monthly variance reports were provided with the March 18, 2013, Second Update to Tab 38 , Filing Requirement 807 KAR 5:001 Section 10(9) (o), sponsoring witness Ms. Billie J. Richert.

[10] The Financial Report for year ending December 31, 2012 (including the variance from budget information) was provided on a Confidential CD on March 18, 2013, in response to OAG DR 1-143 (this data request relates to financial statements and other information provided to the BREC Board of Directors).

single month, but for the entire year's budget to miss the mark by **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** is a concern.

KENTUCKY OFFICE OF THE ATTORNEY GENERAL PROPOSED ADJUSTMENTS

ADJUSTMENT OAG-1-DB - REVERSE BREC'S PROPOSED ADJUSTMENT AND INCLUDE NET MARGINS OF CENTURY SMELTER IN THE REVENUE REQUIREMENT

Q. WILL YOU SUMMARIZE ADJUSTMENT OAG-1-DB?

A. Mr. Brevitz is sponsoring the policy and rationale supporting this OAG adjustment which reverses BREC's net adjustment of $63,028,536 (BREC's adjustment removed the impact of the Century smelter lost margins from the revenue requirement) and includes Century's net margins in the revenue requirement. The estimated net impact of $63,028,536 is included at Mr. Berry's Exhibit Berry-4, page 1 of 1.

Q. IS BREC'S ESTIMATE OF CENTURY'S REVENUE REQUIREMENT IMPACT OF $63.0 MILLION CONSIDERED TO BE KNOWN AND MEASURABLE?

A. No. The OAG's net adjustment of $63,028,536 is based on BREC's estimated impact of the loss of the Century smelter on BREC's operations. OAG Supplemental DR 2-17(b) asked BREC to provide the "actual" impact of removing Century from the historical costs of 2011 and 2012 time periods, but BREC's response stated that the requested information was not available.

Next, OAG DR 2-17(c) asked BREC if it was not possible to identify the "actual" impact of removing Century from 2011 or 2012 time periods, to then provide the "estimated or forecasted" impact of removing Century from these same periods of 2011 and 2012. BREC's response stated that the Company used a forecasted test period because of the complexity of determining the "known and measurable" actual revenues and expenses for 2011 or 2012. BREC stated that in order to determine and remove "actual" impacts of Century from a historic test period, it would need to make a great number of assumptions related to fundamental elements of BREC's operations, including power plant operations, outages, fuel costs, off system sales volumes, and load variations.

However, presumably, BREC also had to make some or all of these same assumptions for purposes of determining a reasonable estimate of the impact of Century upon BREC operations. But BREC has not provided OAG with its detailed documentation, calculations, and assumptions related to its estimated $63 million impact, and therefore it is not possible to determine if BREC's calculated impact is accurate, reasonable, transparent, and prudent. BREC has not provided reasonable substantive documentation regarding the calculated impact of the Century smelter on BREC's operations. However, OAG does not have any other reasonable options except to use BREC's estimated impact of $63 million as the source for its reversal of BREC's adjustment related to the Century smelter.

ADJUSTMENT OAG-2-BCO: ADJUST OFFICER AND MANAGEMENT PAYROLL

Q. WILL YOU SUMMARIZE ADJUSTMENT OAG-2-BCO?

A. This is a two-part adjustment that adjusts and removes certain payroll labor costs for Officers, Management, Nonmanagement, and Non-Bargaining that are included in payroll costs of the forecasted test period (but does not adjust pay for Union employees) as indicated below and shown at Exhibit BCO-2, Schedule A-3:

<u>OAG-2(a)-BCO - Reduce payroll $1,444,273</u> - This adjustment primarily reduces significant increases in base pay awarded primarily during the 2009 period of the Commission's decision in the Unwind Case (plus some other incentive payments included in the forecasted test period). These payroll increases were reflected in BREC's forecasted test period payroll levels.

OAG-2(b)-BCO - Reduce payroll $920,306 - Removes Non-bargaining pay raises of 2.25% for both the base period and forecasted test period. These payroll increases were reflected in BREC's forecasted test period payroll levels.

I have determined that BREC awarded significant pay increases of about $4.4 million to Officers and employees (with individual pay increases reaching 70%), with much of these increases awarded during the 2009 period of the Commission's Unwind decision. The Commission also allowed BREC $4.3 million in the most recent 2011 rate case to use for maintenance which had been deferred. However, it can be argued that BREC's receipt of the $4.3 million merely subsidized and reimbursed the Company for significant questionable pay increases of $4.4 million. This means that BREC placed a priority on its own pay increases as it continued to defer maintenance, thus jeopardizing the safety and service quality of its customers and arguably violating the public trust.

Q. PRIOR TO ADDRESSING YOUR ADJUSTMENT, WILL YOU EXPLAIN HOW BREC HAS APPARENTLY PLACED SIGNIFICANT PAY INCREASES AS A PRIORITY OVER MAINTENANCE?

A. Mr. Holloway's testimony explains how BREC has deferred major maintenance of its generating units since the Unwind Case in 2009, and he indicates the Commission allowed BREC to recover $4.3 million in the

2011 rate case to complete deferred maintenance.[11] However, BREC began rewarding itself with significant permanent pay increases during the period of the Commission's Unwind Case decision in 2009, plus a retention bonus paid to employees one year after the Unwind Case in 2010, along with significant one-time incentives/bonuses paid mostly in 2011 and 2012, which all total about $4.4 million. The $4.4 million payroll increases are shown by year and type in detail at Exhibit BCO-2, Schedule A-3, page 3 of 3.

Thus, BREC management rewarded themselves with substantial pay increases during the period of the Unwind Case which ultimately caused the deferral of important maintenance issues to some degree. In fact, the $4.3 million that the Commission awarded BREC in the 2011 rate case is almost the exact amount of significant pay increases of about $4.4 million, thus it could be argued that the Company used the $4.3 million as reimbursement for its generous permanent pay raises and one-time incentive payments. Although Adjustment OAG-2-BCO reduces certain significant historical and forecasted payroll increases by $2.4 million (that are included in the forecasted test period), this adjustment is not

[11] Holloway Direct, beginning at page 5.

specifically tied to the deferred maintenance issue. However, this adjustment can certainly be justified in part by BREC's decision to favor substantial pay increases over very important maintenance concerns. The prudency of BREC's decision-making process is very questionable, and at the very minimum it was extremely poor timing for management to award itself significant pay increases while seeking to have customers pay for the Unwind transaction.

Q. CAN YOU SUMMARIZE SOME OF THE SUBSTANTIAL PAY INCREASES OVER THE YEARS, INCLUDING PAY INCREASES IN IN 2009 WHEN THE COMMISSION ISSUED ITS DECISION IN THE UNWIND CASE?

A. Yes. This information is illustrated in the table below by year and type of substantial payment (and is part of the information included at Exhibit BCO-2, Schedule A-3, page 3 of 3). I will address some of these issues in more detail later when addressing my adjustment. In addition, some of these amounts had to be estimated because BREC would not provide the related amounts as I will explain later.

Table BCO-1 - Significant Pay Increases:

Significant Pay Increases	Unwind Order 2009	2010	2011	2012	Base Period	Forecast Test Period	Total
Pay increases in year of Unwind	$1.4 m						$1.4 m
Retention bonus -1 year after Unwind		$1.0 m					$1.0 m
Various incentives/bonuses			$1.1 m				$1.1 m
Various incentives/bonuses				$.7 m			$.7 m
Incentives					$.2 m		$2. m
Incentives						$.04 m	$.04 m
Total Signficant Pay Increases							**$4.4 m**

Table BCO-1 is intended to show only the impact of certain significant permanent pay increases along with one-time incentive and bonus payments.[12] It is important to note that this table is not intended to address the more routine cost-of-living pay increases of 1% to 3.5% per

[12] While the "Unwind" case (Case No. 2007-00455) was pending, BREC filed an application for emergency rate relief (Case No. 2009-00040), in which it sought, among other things, permission to require its ratepayers to reimburse $441,000 in bonus payments to 84 employees. Although BREC withdrew its application in Case No. 2009-00040 after it was fully litigated, the Commission's final order (dated Aug. 14, 2009), at p. 2 sharply criticized BREC for asking ratepayers to pay for bonuses during such a period of extraordinary financial hardship:

> "It is for this reason that the Commission would be remiss if it did not caution Big Rivers to **be diligent in determining future expenditures to ensure that all non-essential spending is eliminated.** For example, we note that Big Rivers filed this rate application on March 2, 2009, requesting a 21.6 percent increase, along with a motion to implement the increase on an interim basis 30 days thereafter, claiming that it "will not have sufficient cash to pay its bills as and when due, and its credit or operations will be materially impaired or damaged" [footnote 3: Big Rivers application at 3]. However, Big Rivers subsequently disclosed that, in the two months immediately prior to its rate filing, it paid a total of $441,000 in bonus payments to 84 employees [footnote 4: Big Rivers' Response to Kentucky Industrial Utility Customers, Inc.'s May 4,2009 Second Data Request, item 15]. **The timing of these bonuses was clearly inappropriate in light of Big Rivers' cash crisis. Big Rivers must be diligent in determining future expenses, as well as capital investments, to ensure that it is providing a high quality of service at the lowest reasonable cost.** [emphasis added]

year. It should also be noted that despite the Commission's harsh criticism for attempting to pass along bonuses in BREC's emergency rate case 2009-00040, it appears the company went ahead and did just that, and more, sometime between 2009 through 2012, as indicated in Table BCO-1 above.

Table BCO-1 shows a stair-step process, whereby pay increases were most significant in the early years around the Unwind decision (years 2009 to 2011), and then the pay increases became less as this rate case approached. It appears that BREC has been careful to not include any significant one-time pay increases in its forecasted test period,[13] which is perhaps an attempt to avoid scrutiny and review in this rate case for these important payroll increase issues. Also, BREC would not provide specific information regarding the amount of pay increases by Officer/employee in 2009, and would not even provide the amount of the one-time Retention bonus paid in 2010.[14] It is clear that BREC is very sensitive

[13] BREC did include some lesser amounts of about $38,000 of incentives and "other" compensation in the forecasted test period which are also removed by this adjustment.
[14] BREC's response to PSC 1-32 claims it cannot provide payroll data for 2009 and prior years. BREC's response to OAG 1-253(b) provided only the average or range of pay increase "percentages" for 2009 and other years, but did not provide the amount of increase by Officer or employee. BREC's response to OAG 2-56 would not identify the total amount of Retention bonus paid in 2010, or the amount paid per Officer or employee.

about these significant pay increases, especially those increases tied closely to the timing of the Commission's decision in the Unwind case.

The most substantial permanent salary pay increases were made in 2009, the year of the Commission's decision in the Unwind case. The Officer pay raises in 2009 averaged 48% (ranging from 14.75% to 69.58%)[15], and Mr. Bailey and Mr. Berry were the primary beneficiaries of this pay increase, along with the currently retired Mr. Blackburn. Management and Nonmanagement employees (not including Union employees) also received greater than normal pay raises, averaging 5% to 6% in 2009, along with Management pay raises averaging 7% in 2010 (these 2010 pay raises were grouped into 2009 for simplicity). These amounts were subject to inclusion in my Adjustment OAG-2-BCO which I will address later in this testimony.

In June 2010 (one year after the Unwind case), BREC paid a lump-sum Retention bonus to those employees that accepted the Company's offer of employment, and which were actively employed one-year after the Unwind case.[16] I have estimated this Retention bonus at $1.0 million,

[15] BREC response to OAG 1-253(b).
[16] BREC response to OAG 1-78.

although it could be more or less, but this approximates about 5% of Management payroll (not including Union payroll). The Retention bonus is only in my table for information purposes about significant payroll amounts, and is not part of Adjustment OAG-2-BCO that I will address later.

In 2011 and 2012, BREC paid substantial incentives and bonuses of $1.1 million and $.7 million, respectively. This was the last of the significant pay increases, and BREC did not include any significant incentives or bonuses in the future test period revenue requirement of this rate case. These incentive and bonus amounts are only in my table for information purposes regarding the significant payroll amounts and they are not part of Adjustment OAG-2-BCO (which I will address later) because they were one-time payments and were not permanent increases in payroll levels.

Q. HOW SHOULD THE PRECEDENT OF BREC SUBSTITUTION OF SIGNIFICANT PAY INCREASES FOR IMPORTANT MAINTENANCE ACTIVITY IMPACT THIS CASE?

A. It should certainly contribute to adoption of Adjustment OAG-2(a)-BCO which removes $1.4 million (of the total $4.4 million of significant pay increases) of these significant pay increases that are permanently built into Officer and Management payroll costs today and which are included in the forecasted test period. Of course, if BREC had provided the specific information regarding payroll cost that the OAG requested, the $1.4 million adjustment may have been greater (and there is the possibility the adjustment could be less also).

A policy argument could be made that the Commission's 2011 rate case decision to give BREC $4.3 million in revenue requirements related to deferred maintenance issues has instead been used to subsidize the significant historical pay increases and to finance, and even promote, the Company's $2 million of significant incentive and bonus payments in 2011, 2012, and the base period. Those substantial and important concerns could support a policy decision to withhold at least the same $4.3 million of revenue requirements in this rate case which was arguably not used for its intended purposes from the 2011 rate case.

In addition, if there is any question at all, the Commission should use this as an additional reason to adopt my recommended 1.10 MFIR instead of a 1.24 TIER. The 1.24 TIER provides about $6 to $7 million in additional revenue requirements (or margin) on an annual basis to BREC, over and above the 1.10 MFIR. However, BREC's significant pay increases over time have eaten up 60% to 70% of a one-year margin difference between the 1.10 MFIR and 1.24 TIER. The Company should not be awarded the higher TIER of 1.24 when they cannot be trusted to use this additional revenue requirement of $6 to $7 million to pay for priority maintenance instead of self-serving actions to reward themselves with substantial pay increases. There is no guarantee the Company will not make similar types of questionable decisions in the future to favor their interests over customer interests, and take advantage of the extra margin provided by the 1.24 TIER.

Q. DO YOU PROPOSE A MONITORING PROCESS FOR BREC IN THE FUTURE?

A. Yes, this is addressed near the end of my testimony and this monitoring process is certainly supported by this example of questionable decision making.

Q. SHOULD LOAN HOLDERS ADOPT MORE PROTECTIVE COVENANTS AND CONTROLS OVER BREC?

A. Yes. I have seen cases where loan agreements have included specific covenants for TIER-driven companies that prohibit payments of dividends and certain pay increases for Officers and employees. If this type of covenant had been in place this would have prevented these types of substantial pay increases, but most importantly it would have reduced the amount of deferred maintenance and provided a direct benefit to customers. The OAG cannot tell BREC's loan holders how to run their business, but I believe these types of protective and prohibitive covenants are justified. In addition, it vests another outside party with responsibility and accountability over BREC, so some weight is shifted from the Commission's shoulders. If BREC had to file quarterly reports with lien holders regarding questionable or substantial pay increases, this inserts another party into the equation with a vested interest in BREC's actions and adds another layer of controls to lessen the Commission's burden.

Q. WILL YOU EXPLAIN ADJUSTMENT OAG-2(a)-BCO WHICH REMOVES $1.4 MILLION RELATED TO SIGNIFICANT PAYROLL INCREASES?

A. Yes. This Adjustment OAG-2(a)-BCO is only related to three significant pay increases awarded to Officers and Management and Nonmanagement employees that permanently remains in these employee's pay levels for the forecasted test period, consisting of: 1) significant pay increases during the 2009 period of the Unwind Case; 2) the significant pay increase for Mr. Berry in 2011; and 3) Incentives and "Other" Compensation included for Mr. Bailey and Mr. Berry in the forecasted test period (and these pay raises are shown in detail at Exhibit BCO-2, Schedule A-3, page 1 of 3).

This Adjustment OAG-2(a) differs from the following Adjustment OAG-2(b)-BCO which is only related to the partially forecasted <u>2.25% pay raises</u> awarded to <u>Non-bargaining</u> employees and which are limited to just the base period and the forecasted test period (and both of these 2.25% pay raises are included in the rolled-forward payroll levels for the forecasted test period).

The Adjustment OAG-2(a)-BCO is summarized in Table BCO-2 below in its two parts for: 1) Officers; and 2) Management and Nonmanagement:

Table BCO-2 – Adjustment OAG-2(a)-BCO:

OAG ADJUSTMENT SUMMARY:	Forecasted Test Period	Adjusted Total
M. Bailey - President and CEO	188,667	(188,667)
R. Berry - VP Production	126,211	(126,211)
Adjustment - Officers		(314,878)
Adjustment for Management/Nonmanagement		(1,129,395)
Total Adjustment		**(1,444,273)**

Q. WILL YOU EXPLAIN THE ADJUSTMENT TO <u>OFFICER</u> PAY RAISES RELATED TO ADJUSTMENT OAG-2(a)-BCO?

A. The first sub-part of the adjustment removes $314,878 of payroll increases for Officers Mr. Bailey and Mr. Berry, and this includes removing about $212,667[17] of estimated permanent payroll increases granted to Mr. Bailey and Mr. Berry in 2009 (Unwind case year), about $65,400[18] in additional increases to Mr. Berry in 2011, and $36,811[19] of "Other" compensation for both Mr. Bailey and Mr. Berry that was included in the forecasted test period. As previously indicated, BREC would not provide the amount of payroll increases by Officer/employee in 2009, although BREC did

[17] Exhibit BCO-2, Schedule A-3, page 1 of 3, Mr. Bailey's estimated 2009 pay increase of $170,667 at Column J, line 30, and Mr. Berry's estimated 2009 pay increase of $42,000 at Column J, line 51.
[18] Exhibit BCO-2, Schedule A-3, page 1 of 3, Mr. Berry's 2011 pay increase of $65,400 at Column J, line 45.
[19] Exhibit BCO-2, Schedule A-3, page 1 of 3, Mr. Bailey's "Other" pay increase of $18,000 at Column J, line 14, and Mr. Berry's "Other and Incentive" pay increase of $18,811 at Column J, line 35.

provide information for 2009 showing average pay increases for Officers of 48%, ranging from about 15% to 70%.[20] I used this information and estimated a 50% increase for Mr. Bailey and estimated a 25% increase for Mr. Berry.[21] I have included additional calculations regarding this part of the adjustment at Exhibit BCO-2, Schedule A-3.

Q. WILL YOU EXPLAIN THE ADJUSTMENT TO <u>MANAGEMENT AND NONMANAGEMENT</u> PAY RAISES RELATED TO ADJUSTMENT OAG-2(a)-BCO?

A. This second sub-part of the adjustment removes about $1,129,395[22] of payroll increases for Management and Nonmanagement employees (but not including any Union employees), and this includes removing about 6% of the total pay increases covering both the 2009 period (Management average pay increase of 6.40% plus Nonmanagement pay increase of 4.56%) and the 2010 period (Management average pay increase of 7.08%).[23] I only removed a portion of the pay increases for these years because the percent of pay increase was above more normal levels of 1%

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[20] BREC response to OAG 1- 253(b).
[21] I used a smaller percentage increase for Mr. Berry, because he subsequently received another 31% pay increase in 2011 of $65,400, thus bringing his pay increase percentage to 56% (25% estimated in 2009 and 31% actual in 2011).
[22] Exhibit BCO-2, Schedule A-3, page 1 of 3, Column K, line 11.
[23] BREC provided the average percentage pay increase at OAG 1-253(b).

to 3.5% provided to these employees in most years. I have lumped the adjustment for both the 2009 and 2010 Management and Nonmanagement pay increases into previous Table BCO-1[24] as "2009" pay increases, for simplicity purposes. Again, this amount is an estimate because BREC would not provide the actual amount of payroll increases given for these years. I have included additional calculations regarding this part of the adjustment at Exhibit BCO-2, Schedule A-3, page 1 of 3.

Q. WHY DID YOU REMOVE A PORTION OF OFFICER, MANAGEMENT, AND NONMANAGEMENT PAYROLL INCREASES IN ADJUSTMENT OAG-2(a)-BCO?

A. I only removed that portion of Officer, Management and Nonmanagement pay increases that represents permanent pay increases that are still carried forward and included in these related employee's payroll levels for the forecasted test period. In addition, I only adjusted for unusually significant and questionable pay increases for the period 2009 through the forecasted test period that are included in existing payroll levels of employees, and I did not remove more routine cost-of-living payroll increases as part of this adjustment (although I will address later in this

[24] Also, see Exhibit BCO-2, Schedule A-3, page 3 of 3, the "2009 pay increases" of $1.4 million at Column C, line 1, which includes total adjustment amounts of OAG-2(a)-BCO for Officers of $314,878 plus OAG-2(a)-BCO for Management and Nonmanagement of $1,129,395.

testimony the removal of the 2.25% pay increase for the base period and forecasted test period as the second part of Adjustment OAG-2(b)-BCO).

The largest part of this adjustment removes the significant payroll increases awarded in 2009 during the year of the Commission's decision in the Unwind case. I question the timing and prudency of these payroll increases in relation to the Unwind proceeding. And as I previously indicated, I don't believe it is reasonable that BREC placed significant payroll increases as a priority over necessary maintenance, and which caused the deferral of important maintenance. BREC continues to assert problems with deferred maintenance in this proceeding as addressed in the testimony of Mr. Holloway, but the Company needs to assume responsibility for part of this deferral problem that it helped create based on its apparent decision to substitute questionable payroll increases for necessary maintenance. The Company's payroll increases are contrary to customer interests regarding the importance of maintenance in preserving and promoting service quality and safety.

BREC should not be rewarded for its historical and continuing actions that placed a premium on officer and management payroll increases, because there is no guarantee that these actions will not be repeated in future years when the Company knows it does not face a rate case review. It appears that the Company has at least temporarily cut-back its amount of incentives and bonuses in the base period and test period in an attempt to avoid scrutiny and review of these issues in this rate case, although the Company has also thwarted OAG's attempt to objectively evaluate this information and its impact on this rate case. The Commission should adopt OAG's payroll adjustment and send a strong signal to BREC that maintenance must be a priority over significant pay increases for officers and management.

Q. MOVING TO THE SECOND PART OF THIS ADJUSTMENT, REGARDING OAG-2(b)-BCO, WHY DID YOU REMOVE THE BASE PERIOD AND FORECASTED TEST PERIOD PAY INCREASES OF 2.25% RELATED TO NON-BARGAINING EMPLOYEES?

A. This portion of my adjustment is shown in Table BCO-3 below, and BREC seeks recovery in this rate case of both the 2.25% Base Period pay increase of $470,802, along with the 2.25% Forecasted Test Period pay increase of

$449,504 per its response to PSC 1-34.[25] I have removed both of these Company-proposed adjustments.

Table BCO-3 – Remove 2.5% Pay Increases Non-Bargaining Employees:

		Base Period	Forecasted	
% Pay Increase		2.25%	2.25%	
Officers & Management	PSC 1-34	470,802	449,504	**(920,306)**

I have removed the Forecasted Test Period pay increase of 2.25% because this is related to the 12-months ending August 31, 2014, and these increases are not known and measurable at this time. Furthermore, it is not possible to anticipate or evaluate non-bargaining employee performance or cost of living this far in advance of August 2014 to determine if a 2.25% increase is justified. Also, the number of related employees could change by August 31, 2014, so the number of employees to which the pay increase is applied is not known or measurable at this point. It can also be argued that pay increases in the past have been sufficient and significant. Finally, the Company should not be rewarded for withholding important payroll data from OAG, other intervenors and the Commission, especially when those costs are included in the revenue requirements and can significantly impact rates in this case.

[25] Exhibit BCO-2, Schedule A-3, page 1 of 3, Columns D, E, and F, line 11.

I removed the Base Period pay increase of 2.25% related to non-bargaining employees because I am not aware that BREC has provided any updated actual calculations to substitute for its "forecasted" 2.25% increase. It is not clear if the 2.25% forecasted amount is accurate or reasonable. Again, I believe it can be argued that pay increases in the past have been sufficient and significant. Finally, I believe it is reasonable to put all pay increases on hold so that BREC can use these funds in part to catch-up on its deferred maintenance, and BREC needs to show a good faith commitment to improving maintenance as a priority over pay increases.

Q. WHY DID YOU ALLOW BREC'S PROPOSED UNION PAY INCREASES IN THIS RATE CASE?

A. It is my understanding that these pay increases are supported by actual union contracts and so the amounts are more known and measurable than the pay increases for Officers and Management. There is some argument for removing these amounts, but my position on payroll is mitigated by allowing these union-related pay increases.

Q. HAS BREC ATTEMPTED TO JUSTIFY ITS SIGNIFICANT PAY INCREASES IN 2009 AND OTHER YEARS WITH A COMPENSATION STUDY OR A COMPARISION OF ITS SALARIES TO SIMILAR COMPANIES IN THE MARKET?

A. No. BREC has not provided any explanation or supporting documentation for these significant payroll increases. BREC seems more interested in deferring attention away from this subject matter, by virtue of its failure to provide documentation identifying the total pay increases in 2009 (and other years) and the amounts by Officer and employee.

The OAG 1-254 asked BREC to identify the most recent date that it (or an outside consultant) compared its employee compensation levels to market compensation studies, and to provide a copy of the report, analysis, assumptions underlying the study, findings, and to identify all payroll increases that were implemented as a result of the review. BREC did not provide this requested information. Instead, BREC's response referred to PSC 1-33 and findings from the Towers Watson Competitive Market Assessment Review completed in 2012 and several other salary/benefits studies.

Q. WHAT DID YOU CONCLUDE FROM REVIEWING THE TOWERS WATSON REPORT AND RELATED MATERIALS?

A. I reviewed the Towers Watson Report ("TW Report") provided with PSC 1-33, along with other information. However, I did not see any detailed studies or supporting documentation that justified the significant pay increases in 2009 and 2011 for officers Mr. Bailey and Mr. Berry. In addition, adequate supporting documentation was not available to fully assess and evaluate the reasonableness of compensation levels of Mr. Bailey and Mr. Berry in comparison to the market for similar benchmarked job positions. In total, BREC did not provide any information that supported the current pay levels of Mr. Bailey and Mr. Berry.

ADJUSTMENT OAG-3-BCO - CORRECTION TO INCLUDE THE COMMISSION'S RATE RELIEF IN PRIOR REHEARING ORDER AND OTHER BREC CORRECTIONS

Q. WILL YOU SUMMARIZE ADJUSTMENT OAG-3-BCO?

A. This adjustment considers the impacts of BREC's proposed revised exhibits (and related revised adjustments) provided in response to PSC DR 2-36, and changes the reduction in the revenue requirement impact from BREC's proposed amount of $1,507,989 to a corrected amount of $1,568,516 as shown at Exhibit BCO-2, Schedule A-4.

BREC's response to PSC DR 2-36 states that the revised exhibits reflect the impact of the Commission's Rehearing Order (increased revenues of $1,042,535), along with corrections of errors and other changes in proposed adjustments and revenue requirements. BREC claims this information supports a reduced revenue requirement of $1,507,989, although the detailed workpapers appear to support a reduced revenue requirement of $1,568,516 (and this is the amount of adjustment that I will propose) as set forth below:

1) Impacts of additional revenue increases of $1,042,535 from the Commission's Rehearing Order;

2) Correction of the BREC adjustment related to prior year rate case expense amortization at Exhibit Wolfram-2, Reference Schedule 1.09 (this change is not identified in the written response by BREC, but is included in calculations at revised Exhibit Wolfram-4.2, page 11 of 16).

3) Correction of expense adjustments for FAC, ES, Non-FAC PPA (Exhibit Wolfram-2, Reference Schedules 1.01, 1.02, 1.03, respectively), along with Lobbying Expenses (although BREC's written response identified a change in Lobbying Expense in its revised exhibits, the adjustment amount of $70,923 is the same as BREC's original filing) - - all identified in PSC 2-39 (all updated amounts included at revised Exhibit Wolfram-4.2, page 11 of 16);

4) Elimination of the rounding errors identified in PSC 2-40; and

5) Correction of the calculation of depreciation expense on fully-depreciated plant identified in AG-277(c).

Q. **BEFORE ADDRESSING THE REVISION TO BREC'S RATE FILING RELATED TO THE COMMISSION'S DECISION IN THE PRIOR RATE CASE, WILL YOU PROVIDE SOME RELEVANT BACKGROUND?**

A. Yes. In the prior rate case (Case No. 2011-00036), BREC initially sought a rate increase of $39.95 million (9.2% increase over its normalized test year revenues), BREC subsequently revised its filing to $39.34 million and the Commission's Order relied on this amount for adjustments (although this amount did not reflect three items which reduced BREC's proposed increase to $29.60 million).[26]

The Commission's Order dated November 17, 2011, granted BREC an increase in wholesale electric base rates of $26,744,776.[27] It is my understanding that BREC reflected the entire amount of these additional revenues in its forecasted test year rate filing in the current rate case.

[26] *In the Matter of: Application of Big Rivers Electric Corporation for a General Adjustment in Rates*, Case No. 2011-00036, dated November 17, 2011 (page 1).
[27] *In the Matter of: Application of Big Rivers Electric Corporation for a General Adjustment in Rates*, Case No. 2011-00036, dated January 29, 2013 (page 1). The amount of the rate increase of $26,744,776 granted to BREC in the Commission's Order dated November 17, 2011 is specifically identified in the Commission's Rehearing Order dated January 29, 2013 (page 1), along with additional rate relief of $1,042,535 (p. 24).

However, the Commission's Rehearing Order dated January 29, 2013, modified the original order and granted BREC additional rate and revenue increases of $1,042,535 which were not included in BREC's filing.

Q. HAS BREC FORMALLY REVISED ITS APPLICATION FOR THE IMPACT OF ADDITIONAL REVENUES OF $1,042,535 FROM THE PRIOR RATE CASE?

A. No. At this time, BREC has not formally revised its application, has not formally filed any amended testimony, and has not formally reduced the original amount of its proposed revenue increase of $74.5 million to the best of my knowledge. The Company has provided what it references as updated exhibits, and these might be used for an updated filing in the future. Therefore, I am proposing these revised amounts as an adjustment.

Q. DID YOU PRIMARILY RELY ON BREC'S UPDATED EXHIBITS FOR YOUR REVISION TO BREC'S FILING?

A. Yes. Mr. Wolfram's testimony states that if the Commission issues an order on rehearing in Case No. 2011-00036 resulting in a change in base rates, BREC would have to adjust the rates proposed in this filing. This decision is final now, so I am addressing the impact as an adjustment in this case. Subsequently BREC's response to PSC DR 2-36 provided certain revised exhibits as a result of the Commission's January 29, 2013 Rehearing Order.[28] These revised exhibits reflect the impact of additional revenues of $1,042,535 from the Commission's Rehearing Order, along with additional changes and corrections of errors. In addition, BREC states that these revised exhibits do not include the impact of BREC's amended application in Case No. 2012-00492 (to reflect the reduction in certain costs due to refinancing) as described in its response to PSC DR 2-13 (and other data requests).

Q. CAN YOU SUMMARIZE THE TYPES OF CHANGES REFLECTED IN BREC'S REVISED EXHIBITS AND DO THESE AMOUNTS RECONCILE?

A. BREC's response to PSC DR 2-36 states that the total impact of these changes is a reduction in the original revenue requirement of $1,507,989. However, there is a small unreconciled difference of about $60,000 between Mr. Siewert's revised exhibits and Mr. Wolfram's revised exhibits. Mr. Wolfram's revised Exhibit Wolfram-4.2, page 9 of 16, shows

[28] BREC's response to PSC DR 2-36 included certain revised exhibits for Mr. Wolfram, Mr. Yockey, and Mr. Siewert.

total operation and maintenance expense of $389,053,393 and Mr. Siewert's revised Exhibit Siewert-3.2, page 1 of 1, shows Total Operation and Maintenance Expense of $389,115,893 (which is calculated as $41,106,471+$5,244,047+$216,483), which results in an unreconciled difference of $62,500 (which is calculated as $389,115,893 - $389,053,393).

In addition, the original forecasted amounts at August 31, 2014 (without the proposed rate increase) shows Total Operation, Maintenance, and Depreciation Expense of $433,158,383 less Wolfram's revised adjustments (Adjustments at Reference Schedules 1.01 through 1.12) of $53,452,088 equals adjusted Expenses of $379,706,295. However, Mr. Wolfram's revised Exhibit Wolfram-4.2, page 11 of 16, shows an amount of $379,644,679, for an unreconciled difference of $61,616 ($379,706,295 - $379,644,679).

I have reflected the adjustment of $1,568,516 at Exhibit BCO-2, Schedule A-4, Column C because this appears to be more consistent with underlying amounts included in BREC's original filing.

Q. WERE YOU ABLE TO RECONCILE BREC'S REVISED ADJUSTMENT RELATED TO PRIOR YEAR RATE CASE AMORTIZATION EXPENSE TO ITS ORIGINAL ADJUSTMENT?

A. No. BREC's filing includes an adjustment of $640,753[29] to reflect the 3-year amortization of rate case expense in the prior rate case (Case No. 2011-00036), and BREC's revised exhibits show a reduced adjustment amount of $203,352.[30] BREC's response to Supplemental OAG DR 2-23 states that the revised amount of $203,352 reflects the amortization of the uncollected balance of rate case costs approved by the Commission's Rehearing Order dated January 29, 2013 and this reflects an adjustment for ratemaking purposes only, because there are no prior rate case expenses included in the forecasted test period. Although BREC's revised exhibits appear to reduce prior year rate case expense amortization by $437,401 ($640,753 - $203,352), I could not reconcile the amount of $203,352 to any supporting documents or amounts addressed in prior Commission orders. Therefore, this revised rate case expense amount of $203,352 may be subject to further adjustment or changes.

[29] Wolfram, page 17, lines 18 to 22, and Exhibit Wolfram-2, Reference Schedule 1.09.
[30] BREC response to PSC 2-36 and related revised exhibits, revised Exhibit Wolfram-4.2, Adjustment 1.09.

ADJUSTMENT OAG-4-BCO - COST SAVINGS FROM JULY 12, 2012 REFINANCING OF RUS SERIES A NOTE

Q. WILL YOU SUMMARIZE ADJUSTMENT OAG-4-BCO?

A. This adjustment reflects the cost savings related to BREC's July 12, 2012 refinancing of its RUS Series A Note, resulting in a total cost savings of $4,189,083 as provided in BREC's response to OAG DR 1-63(c) and related to the amended application in Case No. 2012-00492 (Refinance Case). BREC's response to PSC DR 2-36 states that the Company has not reflected the amount of this cost savings in the rate case because the Commission has not yet approved BREC's proposed refinancing in Case No. 2012-00492. I am reflecting this adjustment is this rate case because the Commission has now approved BREC's revised application in that case.

The related impact by type of cost savings is set forth in Table BCO-4 that serves as the basis for the related adjustment:[31]

[31] This same table, along with additional information, is included at Exhibit BCO-2, Schedule A-5.

Table BCO-4 – Refinancing Cost Savings:

Description	Adj.
Series A Note refinancing ($440,771,549*1.43%)	(6,303,033)
Additional borrowing ($96,228,451*4.41%)	4,243,675
Int. expense CTC loan	2,214,409
Int. income CTC investment	(1,771,527)
OAG-4(a)-BCO -- Int. Expense Adjustment	**(1,616,476)**
OAG-4(b)-BCO - Estimated Patronage Allocation Adjustme	**(2,706,448)**
Amortized loss on reacquired RUS Series A Note	60,482
Amortize refinancing cost	73,359
OAG-4(c)-BCO - Amortized Loan Adjustment	**133,841**
Total Impact of Cost Savings from Loan Refinancing	**(4,189,083)**

In the above table, I have netted the Interest Income on CTC Investment of $1,771,527 with the related increases in Interest Expense to produce a net reduction in Interest Expense, because without this netting process the refinancing transaction would have produced a net increase in Interest Expense. I do not believe that it is reasonable, nor the intent, that this refinancing would result in a "net" increase in Interest Expense, so a net savings in Interest Expense is produced by this netting process.

ADJUSTMENT OAG-5-BCO: ADJUST BREC'S ESTIMATED RATE CASE EXPENSE

Q. WILL YOU SUMMARIZE ADJUSTMENT OAG-5-BCO?

A. BREC proposes to amortize total estimated rate case expenses of $1,585,977 over three years, for a total amortized expense of $528,659 in this proceeding. I am proposing to reduce total estimated rate case expense by $1,027,929, and disallow 3-year amortized rate case expenses of $342,643. These estimated rate case expenses should be removed and reduced for numerous reasons, including about 60% of related expenses that are unspent, speculative, no supporting documentation, and not known and measurable in terms of: if the amounts will be spent, when, by whom, and for what possible purpose besides rate case expense.

BREC has not provided reasonable documentation to support recovery of these significant and largely speculative rate case expenses. Exhibit BCO-2, Schedule A-6 provides supporting documentation for this rate case expense adjustment, including information that shows rate case costs incurred and unspent to-date by consultant/attorney.

Q. **WILL YOU SUMMARIZE SOME OF THE REASONS FOR ADJUSTING RATE CASE EXPENSE?**

A. Yes. Some of the reasons for removing and adjusting rate case expense for consultants and outside attorneys include the following:

1) Through January 2013, about 60%[32] (or $.9 million) of estimated rate case expenses remain unspent, and much of these remaining estimated expenses are speculative, not supported by meaningful documentation, are not explained as to the purpose of the costs, and are not known and measurable.

2) BREC has failed to provide documentation or other objective, verifiable evidence regarding its rate case expenses, and the Company did not provide various supporting information that was requested in OAG data requests.

3) Some of the hourly rates for legal services are excessive and BREC has not provided documentation to show that highly compensated legal counsel is essential for particular tasks as required by the Commission's Rehearing Order in the prior rate case.

4) In the prior rate case, intervenors raised concerns about excessive legal fees, indicating that BREC's Washington, D.C. attorneys Hogan Lovells US LLP charge hourly rates that are three times greater than BREC's Kentucky law firm. BREC still uses the firm Hogan Lovells, although none of these related legal expenses were designated as part of the estimated rate case expense for this proceeding (so presumably the firm is used for other services, although these amounts should also be removed as excessive). However, because 57% of estimated rate case legal fees remain unspent at this time, are speculative, and cannot be traced to a specific attorney - - it is possible that part of these legal fees will be paid to Hogan Lovells in the future (after this rate case is concluded) and thus excessive legal fees will have been spent after-the-fact and without recourse in this proceeding.

[32] The 60% of estimated unspent rate case expense has been updated for BREC's April 19, 2013, update of PSC DR 1-54(a) showing invoices and additional rate case expenditures.

5) Some of the legal costs are supported by contracts that identify lobbying or political activity as part (or most) of the services to be provided, and lobbying costs are not allowed to be recovered in the rate case.[33] Including these types of expenses in this proceeding as "rate case expenses" negatively impacts upon the credibility of BREC and raises concerns about the legitimacy and reasonableness of other claimed rate case expenses.

6) Because a significant portion of the consulting and legal costs are estimated and remain unspent as of the latest date, it is not possible to determine if the "estimated" amounts to be spent are related to the rate case or some other services to be provided in the future or if the amounts may be related to non-recurring issues that would normally be excluded from the rate case.

7) It is not clear why BREC needs rate case assistance from four different outside law firms, and this raises the concern of whether part of these estimated costs will be actually used for rate case purposes in the future, or whether BREC has included budgeted legal fees for other services in its estimated rate case costs.

8) At least one legal invoice includes the cover page designating all fees as related to "rate case", although the invoice has been marked up in writing to identify some costs that are not rate-case related.

9) It is not clear if complete legal invoices have been provided in all cases in support of the costs.

10) Some of the estimated consulting costs are excessive considering the scope of services, the remaining time for this engagement, and considering similar services provided in the prior rate case for which there are no significant economies of scale or cost savings.

11) Contracts or engagement letters are not available for any legal costs which could be used to document the purpose and amount of legal costs, thus leaving a significant portion of these costs as speculative and without supporting documentation.

[33] PSC 1-45.

Q. WHAT TYPE OF INFORMATION AND DATA REQUEST RESPONSES DID YOU REVIEW?

A. I reviewed BREC's responses to numerous data requests issued by the OAG and PSC Staff. BREC's January 29, 2013 response to PSC DR 1-54 showed the estimated rate case expenses for each consultant/attorney that comprise the Company's total estimated rate case expense of $1,585,977, and this amount is amortized over three years to reflect estimated amortized rate case expenses of $528,659 in the rate filing.

The January 29, 2013, initial response to PSC DR 1-54 showed actual costs incurred by consultant/attorney from July 2012 through November 2012. BREC has provided three subsequent updated responses to PSC DR 1-54, with the "First Update" provided February 15, 2013, which shows rate case expenses incurred by consultant for December 2012, the "Second Update" provided March 18, 2013, provides updated expenses for January 2013, and the "Third Update" provided April 19, 2013, provides updated expenses for February 2013.

Thus, for the seven-month period July 2012 through February 2013, the information shows that BREC has only incurred 36% (and not incurred

64% of its costs) of estimated <u>consulting</u> (non-legal) rate case expenses,[34] and has only incurred 43% (and not incurred 57% of its costs) of its estimated <u>legal-related</u> rate case expenses[35] as shown in the table below[36]:

Table BCO-5 - Rate Case Expense Not Incurred to Date:

Vendor	**Total Actual Incurred to Date**	Total Estimated Rate Case Expense	**% Expenses Not Incurred to Date**
Non-Legal:			
Catalyst Consulting	172,066	411,255	58%
Burns and McDonnell	42,300	100,297	58%
American Man. Con.	2,065	-	
Aces Power Marketing	-	42,940	100%
Other ($55,785)	-	55,785	100%
Dan Walker	7,750	-	
Subtotal Non-Legal	**222,181**	**610,277**	**64%**
Legal:			
Sullivan, Mountjoy	164,435	454,620	64%
Dinsmore & Shohl	233,707	521,080	55%
Orrick, Herrington	15,244	0.00	
Hunton & Williams	1,730	0.00	
Subtotal Legal	**415,116**	**975,700**	**57%**
Total - All Rate Case Expense	**637,297**	**1,585,977**	**60%**

Thus, a significant amount of estimated rate case expense remains unspent, speculative, not known and measurable in terms of when or if it

[34] Exhibit BCO-2, Schedule A-6, Columns I and K, line 7, which shows amounts spent and percent unspent to date for each non-legal consultant.
[35] Exhibit BCO-2, Schedule A-6, Columns I and K, line 14, which shows amounts spent and percent unspent to date for legal costs.
[36] This table is from information included at Exhibit BCO-2, Schedule A-6, which provides calculations supporting this rate case expense adjustment.

will be spent, by whom, and for what specific purpose besides this rate case.

Q. DID THE COMMISSION EXPRESS CONCERN WITH BREC'S RATE CASE EXPENSES IN THE PRIOR PROCEEDING AND ESTABLISH SPECIFIC CRITERIA FOR RECOVERING FUTURE RATE CASE EXPENSES?

A. Yes. In the prior rate case, various intervenors, Commission staff and the Commissioners themselves raised concerns about the level of rate case expenses and the excessive hourly rates charged by BREC's Washington, D.C. office of attorneys Hogan Lovells US LLP ("Hogan Lovells"), which were about three times the highest hourly rates charged by BREC's Kentucky law firm.[37] The Commission reduced Hogan Lovell's legal fees by 20% because their total fees of $897,200 significantly exceeded the original estimated fees of $174,000 included in BREC's application.[38] Most importantly, the Commission noted that BREC bears the burden of proof and the recovery of rate case expenses in future rate cases must meet the following criteria:

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[37] *In the Matter of: Application of Big Rivers Electric Corporation for a General Adjustment in Rates,* Case No. 2011-00036, January 29, 2013 Order, p. 3.
[38] *Id.*, p. 6.

1) the rate case expenses must be supported by unredacted copies of invoices; and

2) there must be a showing that the use of highly compensated legal counsel was essential for the particular tasks being performed.[39]

Q. DID YOU RELY UPON THE COMMISSION'S CONCERNS FROM THE PRIOR RATE CASE ORDER AS A REASON TO DISALLOW RATE CASE EXPENSES IN THIS PROCEEDING?

A. Yes, I relied on the Commission's specific criteria as the rationale for removing some rate case expenses, and I removed other expenses by relying on the Commission's underlying rationale. For example, I removed all of the legal expenses of attorneys Orrick, Herrington & Sutcliffe LLP ("Orrick") because the firm's hourly rates are excessive (in some cases higher than those charged by the Hogan Lovell Washington, D.C. firm) and BREC did not provide documentation to show that "the use of highly compensated counsel was essential for the particular tasks being performed" as required by the Commission's prior order.

I have not allowed $15,244 of rate case expenses of Orrick Herrington & Sutcliffe ("Orrick") incurred to date because of excessive legal fees (amounts provided in response to PSC 1-54). BREC did not specifically

[39] *Id.*, p. 6.

refer to Orrick in its estimated rate case costs, but BREC did include an "Other" category of estimated rate case expenses of $55,785 and Orrick could be interpreted to fall within this category. Orrick may have been excluded from mentioning in this "Other" category of rate case expense in an attempt to avoid scrutiny of its excessive legal fees. In addition, BREC did not include Orrick's hourly billing rates along with other attorney billing rates that were disclosed at the response to PSC 1-54(b), and this looks very unusual. It appears that BREC did intend to include Orrick costs as part of rate case expense because BREC's February 15, 2013 first updated response to PSC 1-54 provides copies of Orrick's invoices and this data request states, "Provide the following information concerning costs for the **preparation of this case."** (Emphasis added). Also, a handwritten note on this page identifies certain "rate case" expense amounts without an explanation of services (which also justifies removal of these expenses), although the remainder of the invoice is redacted.

Orrick's January 8, 2013, invoice shows the highest hourly rates of $995.00, $760.00, and $695.00 for three attorneys providing services to BREC.[40] In comparison, BREC's January 29, 2013 response to PSC DR 1-54 provides a

[40] BREC's response to PSC 1-54(a), page 18 of 22, first update of February 15, 2013.

comparison of hourly rates of all consultants/attorneys, and the highest hourly rates for the law firms are $280.00 for Dinsmore & Shohl LLP ("Dinsmore") and $220.00 for Sullivan, Mountjoy, Stainback & Miller, P.S.C. ("SMSM"). Clearly the Orrick hourly rates are excessive compared to the other attorney's hourly rates and these amounts should be removed. If any Orrick legal fees are included in other "non-rate case" expenses of the revenue requirement, these amounts should be removed also.

Q. IS BREC'S INCLUSION OF THE EXCESSIVE ORRICK LEGAL FEES CONTRARY TO MR. YOCKEY'S TESTIMONY?

A. Yes. Mr. Yockey states that BREC is "closely managing" its rate case costs, and it has "addressed the issue of outside legal expenses, which was contested in the 2011 Rate Case."[41] I interpret Mr. Yockey's comments to mean that BREC has not included any "excessive legal fees", or has at least provided an explanation of why those excessive legal fees are necessary in response to the Commission's prior rate case order. Mr. Yockey's testimony is not accurate or consistent with the rate case expenses sought by BREC, because the amounts of Orrick's legal fees are excessive and BREC does not explain why these fees are justified.

[41] Yockey Direct, Tab 65, page 11, lines 9 to 11.

Q. HAS BREC EXPLAINED WHY THE SIGNIFICANT AMOUNT OF LEGAL EXPENSES ARE NECESSARY FOR FOUR DIFFERENT LAW FIRMS IN THIS RATE CASE PROCEEDING?

A. No. Mr. Yockey's testimony explains that BREC is using two law firms for this rate case, both SMSM and Dinsmore.[42] However, Mr. Yockey's testimony is not accurate, because BREC is really using four law firms, including Orrick and Hunton & Williams.[43] The inaccuracy of Company testimony regarding rate case expense raises concerns with the credibility of all rate case expenses requested in the revenue requirement.

BREC has included estimated legal costs of $975,700[44] (not including Orrick and Hunton & Williams) in this rate case for SMSM and Dinsmore, and has incurred $398,142[45] (or 43% of estimated costs to date, although some of this amount is considered to be unreasonable or excessive) of its original estimated legal expenses to date through the April 19th update of

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[42] Yockey Direct, Tab 65, page 11, lines 11 to 15.

[43] Expenses for Hunton & Williams were incurred for the first time with the April 19, 2013 "Third Update" of expenses at PSC 1-54.

[44] Exhibit BCO-2, Schedule A-6, Column J, line 14.

[45] BREC's original estimated legal expenses that have been incurred to date are $398,142, and this consists of total legal expenses incurred to date of $415,116 (Exhibit BCO-2, Schedule A-6, Column I, line 14) less Orrick legal fees of $15,244 and Hunton & Williams legal fees of $1,730 (Exhibit BCO-2, Schedule A-6, Column H, lines 12 and 13) which <u>were not included</u> in BREC's original estimated legal expenses.

PSC 1-54.[46] BREC's estimated legal costs represent 62% of its total estimated rate case expense. I have allowed total legal expenses of $300,000[47] for SMSM and Dinsmore and disallowed $675,700 (and $560,584 of BREC's estimated legal costs have not even been incurred to date). All of this information is shown at Exhibit BCO-2, Schedule A-6.

The estimated legal fees are significant and unjustified. The total estimated legal costs of $975,700 (not including Orrick and Hunton & Williams), when divided by an average hourly rate of $230.00, equals 4,242 hours to be spent on this rate case. If these 4,242 hours were expressed as the required time of one person, this would translate to 106 weeks at 40 hours a week or about 27 months. The estimated legal fees are excessive and not supported by proper documentation.

In addition, BREC has not specifically explained why the services of four different law firms are necessary for this rate case, and why this does not result in overlap or inefficient services. In addition, because a significant amount of these estimated legal expenses are unspent, this raises concerns if part of these future legal expenses are unrelated to rate case expense

[46] Legal fees incurred to date are provided at PSC 1-54, the January 29th initial response, the February 15th update, the March 18th update, and the April 19th update.
[47] Exhibit BCO-2, Schedule A-6, Column N, lines 10 and 11.

and will be used for other purposes, including some possible non-recurring or extraordinary events or situations that might justify a rate case adjustment to remove these costs in a typical rate case.

Q. DID YOU REVIEW ACTUAL INVOICES OF ATTORNEYS AND DID YOU IDENTIFY PROBLEMS?

A. Yes. These invoices were provided by BREC primarily in response to PSC 1-45 and 1-54. I was not able to determine that all amounts on the attorney invoices were related to rate case expense, there appears to be overlap of legal charges within and between law firms, some charges appear to be excessive, and there are some unusual charges. I have identified some unusual and questionable charges below based on scanning of the legal invoices and while these amounts for one or two invoices may not be significant in dollar amount, these same types of issues spread over the entire estimated legal rate case costs could be material. Also, these issues go to the overall reasonableness of the legal costs. In total, I was not able to determine that legal costs related to the rate case are reasonable and appropriate.

I have summarized below some examples of unusual and questionable charges from the legal invoices (although I am not including a complete list of these items):

1) Dinsmore December 2012 invoice (PSC 1-54a) - Various hours were charged to issues related to "contract or contractual issues", although this contract is not explained. A handwritten note on the invoice identifies amounts related to discussion of "Smelter-related issues that are not rate case expenses." If the "contract" issue is related to the "Smelter contract" issues that BREC admits are not rate case expenses, then BREC has included inappropriate amounts in rate case expense. Furthermore, BREC has not included any "adjustment" in its rate case expenses to remove these amounts related to "Smelter" which they indicate are not rate case related.

2) Dinsmore December 2012 invoice (PSC 1-54a) - About one-half of the legal hours charged for December (29.4 hours charged of 63.80 billed), include various hours charged as communication between the Dinsmore Partner and Associate working on this case (although sometimes other related issues are mixed in with these charges). In addition, one line item indicates that the Dinsmore Associate charged nearly one and one-half hours to the case for writing deadlines and due dates into the calendar of the Partner on November 5, 2012. I understand that the Partner and Associate working on the case need to communicate, but these "internal" legal charges appear unusual and could be a significant part of the legal costs.

3) Dinsmore December 2012 invoice and SMSM January 2013 invoice (PSC 1-54a) - Dinsmore line items that include the attorneys review of "depreciation issues" totaled 17.6 hours for November (although sometimes other issues were mixed in). Also, there is at least one line item charge on an SMSM January invoice by a Partner that they are also reviewing depreciation issues for BREC. This would appear to be an overlap of charges between the two law firms, and raises concerns regarding other overlaps and charges.

4) Dinsmore February 2013 invoice (PSC 1-54 - updated April 19, 2013) - Dinsmore legal expenses for this one month are $178,000, and 764 hours (before discount), which equates to billings of 27 hours a day for all 28 days of the month, or 3 full-time legal persons a day for all days of the month (the Dinsmore invoice shows that 12 persons billed legal time during the month).

5) SMSM December and January invoices (PSC1-54a) - For some reason, a copy of SMSM's summary invoice and lead letter on SMSM letterhead is never provided with these billings. Only some listing of hours and amounts on plain paper support the billing, the amounts are not shown on SMSM letterhead. This appears very unusual and raises issues if the lead summary invoice page would identify different amounts allocated to the rate case, versus amounts attached as the billing detail.

Q. DOES BREC'S RATE CASE EXPENSE INCLUDE LOBBYING COSTS THAT SHOULD BE DISALLOWED?

A. Yes. BREC has included estimated rate case expenses of $2,065 for American Management Consulting LLC, ("AMC") and although these costs were not specifically identified as included in BREC's estimated rate case costs, the invoices have been included in response to PSC 1-45 which is cited in the response to PSC 1-54 (which relates to rate case expenses). I reviewed the July 17, 2012 letter from AMC to Mr. Bailey setting forth AMC's services to be provided, and the letter focuses on "lobbying and political assignment" services to be provided.[48] The term of the contract is proposed as one year, and AMC charges a monthly retainer, although any

[48] The letter from AMC to Mr. Bailey was provided in response to PSC 1-54 related to rate case expenses.

actual fees billed at $150/hour are offset against the month retainer. These services are clearly related to lobbying and should be removed from rate case expense and any other expenses in the revenue requirements.

Q. DID YOU REDUCE RATE CASE COSTS RELATED TO CATALYST CONSULTING?

A. Yes. Catalyst Consulting ("Catalyst") provides various services to BREC primarily via BREC witness Mr. Wolfram (and also other members of the firm). I reviewed three similarly constructed contracts dated June 1, 2012 (except the 2012-2013 general rates contract was dated July 25, 2012), between BREC and Catalyst related to the following four types of services: 1) Demand Side Management programs and tariffs; 2) 2012-2013 general rates and cost of service; 3) **2011 rate case**; and 4) Environmental Compliance Plan and Environmental Surcharge. All of these Catalyst contracts are with SMSM on behalf of BREC, although the specific reason for SMSM as the intermediary is not clear because the invoices appear to go directly to BREC, unless this treatment can impact SMSM's billing to BREC for oversight of the contract and related matters.

BREC's estimated rate case expense includes $411,255 related to Catalyst, although only $172,099 (42% incurred to date) has been incurred to date.[49] I have allowed $200,000 of these expenses and removed $211,255 of these expenses.[50] I have reduced the estimated expenses related to Catalyst for the following reasons:

1) The four Catalyst contracts only specify an hourly rate of $175/hour for Mr. Wolfram and associates, the contracts do not provide a total budget or estimate of costs for these four services or for this specific rate case. It is not clear how BREC determined estimated rate case expenses of $411,255 related to Catalyst, because I am not aware of any contracts or other documents from Catalyst that includes this amount or any estimated hours for rate case work.

2) A substantial part of the estimated rate case expense of $411,255 could be related to some of the other three services to be provided by Catalyst, and these may not be related to this rate case (or not entirely related to this rate case). The four contracts do not identify amounts or hours to be billed.

3) The total fee of $411,255 appears excessive for the types of services that Catalyst would be providing for this rate case.

4) Because of Catalyst's middleman contract with BREC's attorneys SMSM, the attorneys may be including an up-charge for their services related to managing the contract with Catalyst, or for periodic supervision or review of Catalyst's work. These amounts would be difficult to identify and determine, so a reasonable adjustment to BREC's estimated rate case expense for Catalyst is the only way to address this issue.

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[49] Amounts incurred to date are via the response to PSC 1-54, per the January, February, March, and April updates.
[50] Exhibit BCO-2, Schedule A-6, see the related amounts at Columns I, J, N, and Q, line 1.

ADJUSTMENT OAG-6-BCO: ADJUST FORECASTED PERCENT OF PAYROLL EXPENSED TO HISTORICAL LEVELS

Q. WILL YOU SUMMARIZE ADJUSTMENT OAG-6-BCO?

A. This adjustment takes BREC's forecasted August 31, 2014 test year payroll expense and adjusts it to the average percent of payroll expensed for the three most recent "actual" historical periods, resulting in a reduction of payroll expense of $555,308.[51] The calculation for this adjustment is provided at Exhibit BCO-2, Schedule A-7.

This adjustment is necessary because it appears that BREC's forecasted payroll includes an unusually greater percentage (and related greater amount) of "expensed" payroll which is not consistent with the three most recent actual historical periods. It appears to be very unusual for this spike in payroll expense to occur in the forecasted test period used for establishing revenue requirements in this rate case, because the percent of payroll expensed had been consistently declining for the three most recent actual historical periods of 2011, Base Period ending April 30, 2013, and 2012. This adjustment revises the percent and amount of forecasted payroll expense to the 3-year weighted average of historical actual results.

[51] BREC's forecasted test year payroll and related percentages of payroll expensed and capitalized are per BREC's response to AG 1-75(a).

Q. CAN YOU EXPLAIN THE CONCEPT OF EXPENSED AND CAPITALIZED PAYROLL?

A. Each company expenses a certain amount (and certain percentage) of total payroll to its operating expenses and also usually capitalizes a certain amount (and certain percentage) of its total payroll to the related plant accounts. Sometimes the percent of payroll expensed is called the payroll expense ratio, and the same for the payroll capitalized ratio.

Q. DID BREC ADEQUATELY EXPLAIN THE REASON FOR THE SPIKE IN PERCENTAGE OF PAYROLL EXPENSED IN THE FORECASTED TEST PERIOD?

A. No. OAG 1-55 asked BREC to explain why forecasted test period payroll showed an increase in the percentage of payroll expensed for the first time since 2011. BREC's response is vague and does not provide a meaningful or reliable explanation, and it does not provide any supporting calculations or documentation. BREC merely states that the percentage of payroll expensed and capitalized varies from year-to-year depending upon the number and amounts of more internal-labor-intensive projects and then BREC refers to the testimony of Mr. David G. Crocket regarding the derivation of capital costs included in budget. However, Mr. Crocket's cited testimony does not pertain to this issue, and he does not specifically address or explain the reasons for changes in the percent of payroll expensed or capitalized. BREC has not provided adequate documentation and explanation to support its forecasted payroll costs.

Q. ARE YOU AWARE OF ANY OTHER PUBLIC SERVICE COMMISSIONS THAT HAVE ADOPTED THIS SAME TYPE OF ADJUSTMENT IN A RECENT UTILITY RATE CASE?

A. Yes. The Public Service Commission of Maryland adopted this same adjustment that I proposed in the rate case of Potomac Electric Power Company, when I testified on behalf of the Office of People's Counsel.

> OPC, however, contests the Company's payroll expense factor, arguing that the percentage of total payroll expensed in the 2011 test period is at the highest level in at least the past six years, and is approximately 2.50% higher than the expense factor in 2010. OPC witness Ostrander reduced the payroll expense factor by 2.38% for Pepco and 2.82% for payroll charged to Pepco by Servco. Given that the Company failed to provide any such analysis in this record, we find that OPC's adjustment of a $1,103,000 increase in operating income and a $1,849,000 increase to rate base represents the more appropriate treatment.[52]

[52] In the Matter of the Application of Potomac Electric Power Company for Authority to Increase its Rates and Charges for Electric Distribution Service, Order No. 85028, Case No. 9286, dated July 20, 2012, pp. 27 to 28.

INCOME TAXES

Q. CAN YOU EXPLAIN WHY THERE ARE NOT ANY STATE AND FEDERAL INCOME TAX EXPENSES INCLUDED BY BREC AND OAG IN THE REVENUE REQUIREMENTS CALCULATION?

A. BREC currently has a significant federal and state net operating loss carry-over ("NOLC") which it can carry-forward and use to offset against future federal and state income tax obligations. Thus, there is no federal or state income tax expense to be included in this rate case, because the Company will not incur or pay any federal or state income taxes for the foreseeable future. BREC's filing at Tab 51, pages 1 and 2 explains why it has not included any federal or state income tax expense in this filing. BREC explains that it had a federal net operating loss of $30.1 million at the end of 2011, and for Kentucky state income tax it has a sizeable amount of NOL. OAG concurs with BREC's treatment of reducing income tax expense to $0 in this rate case and not calculating taxes based on rate case determined margins.

Q. DID BREC'S MOST RECENT DECEMBER 2012 AUDITED FINANCIALS REMOVE THE AMOUNT OF DEFERRED TAX ASSETS VIA A VALUATION ALLOWANCE?

A. Yes. BREC's 2012 financial statements (at page 19, Note 6) included an amount of $12.6 million for deferred tax assets related to the tax loss carryforward, and total deferred tax assets of $53.0 million. However, BREC has applied a valuation allowance of $53.0 million to offset and reduce the deferred tax asset balance to $0. Note 6 does not specifically explain the reason for the $53.0 million valuation allowance that reduces the deferred tax asset balance. However, this is presumably related to Note 1 (k) - Income Taxes, which cites to "FASB ASC 740 Income Taxes" and which indicates that tax benefits are recorded only when the more-likely than-not recognition threshold is satisfied and measured at the largest amount of benefit that is greater than 50% likely of being realized upon settlement. Apparently BREC does not believe the benefits of the deferred tax assets will be realized, and thus the amounts have been reduced by the valuation allowance as required by FASB ASC 740. I believe that BREC has accurately reflected the impact of this issue in this rate proceeding, along with reflecting $0 income tax expense in the rate filing.

Q. DO YOU PROPOSE REPORTING AND MONITORING REQUIREMENTS OF BREC?

A. Yes. Because of the OAG's concerns with BREC's financial condition and concerns with other issues identified in this rate case, the following monitoring and related reports should be required and provided to both the Commission and OAG:

1) Immediate Notification:

a) All correspondence and preliminary indications of a "going concern issue" as identified by BREC's auditors.
b) All notification and changes by credit rating agencies.
c) All acts of foreclosure, default proceedings by loan holders, and other similar activities against BREC.
d) All actions that potentially result in payments of incentives, bonuses, and pay raises exceeding 3% annually for each individual employee. A list should show the name of employee, job position, current pay for employee, increase amount and percentage, proposed ending pay for employee, reason for pay increase and how it will be recorded, and type of pay increase (bonus, incentive, retention, etc.).
e) Provide notice if the Company will not be able to meet any required TIER/MFIR or other similar debt/interest coverage requirements.
f) All Board of Director actions or responses related to all of the above.

2) Quarterly Filing:

a) A list of all deferred maintenance by work order and project (with a description of assets and other items by account number that are impacted), with an explanation and documentation supporting why the maintenance must be deferred. The deferred maintenance list must prioritize and rank the most important deferrals, with item (1) on the list being the most important, etc. BREC should explain the implications for safety and service quality of all deferred maintenance. A cash flow analysis should be provided which shows why the maintenance must be deferred.

b) Cash flow analysis of all major items exceeding $1 million individually or $5 million by account, and this should be used to support the previous deferred maintenance filing.

c) A list of all payroll amounts paid per employee that would exceed 3% annually. The information should summarize data as explained at item (1)(d) above.

d) Statement of Operations results showing amounts in Trial Balance format and by primary account, with variance analysis explaining and showing the changes in amount and percentage from the prior quarter of the same year and the prior year, and cumulative year-to-date information showing the same.

e) Identify all extraordinary events and actions that impact the Statement of Operations and Balance Sheet.

f) Identify the loss of major customers, the reason for the loss, and the impact on revenues, expenses and operations.

g) Identify all new and significant contracts that significantly impact revenues, expenses and balance sheet amounts and provide a summary explanation of the contract terms and how it will impact operations.

3) Annual Filing:

a) A summary of all actions and items on an annual basis for items (1) and (2) listed above.

b) The amount and use of federal and state Net Operating Losses in the financial statements.

Q. WHAT IS THE TOTAL IMPACT OF OAG RECOMMENDED ADJUSTMENTS?

A. The total impact of OAG recommended adjustments increases operating income and net margins by an amount of $72,048,665. Mr. Brevitz is sponsoring Adjustment OAG-1-DB which increases operating income and net margins by an amount of $63,028,536, and I am sponsoring the remaining adjustments, Adjustment OAG-2-BCO through OAG-6-BCO, which increase operating income and net margins by an amount of $9,020,129.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION, INC. FOR AN ADJUSTMENT OF RATES	)))	Case No. 2012-00535

AFFIDAVIT OF BION C. OSTRANDER

State of Kansas)

Bion C. Ostrander, being first duly sworn, states the following: The prepared Pre-Filed Direct Testimony, and the Schedules and Appendix attached thereto constitute the direct testimony of Affiant in the above-styled case. Affiant states that he would give the answers set forth in the Pre-Filed Direct Testimony if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, his statements made are true and correct. Further affiant saith not.

Bion C. Ostrander

Bion C. Ostrander

SUBSCRIBED AND SWORN to before me this 7th day of May, 2013.

DELLA J. SMITH
Notary Public - State of Kansas
My Appt. Expires January 26, 2017

NOTARY PUBLIC

My Commission Expires: 01-26-2017

General- Ostrander

Mr. Ostrander is an independent regulatory consultant, a practicing Certified Public Accountant (CPA) and has thirty-four years of regulatory and accounting experience. Mr. Ostrander's firm, Ostrander Consulting, has been providing consulting services since 1990 and he has addressed more than 180 cases in numerous jurisdictions.

Previously, Mr. Ostrander served as the Chief of Telecommunications for the Kansas Corporation Commission (KCC - the regulatory agency for the state of Kansas) from 1986 to 1990, and served as Chief Auditor for the KCC on gas, electric, transportation, and telecom cases from 1983 to 1986. Mr. Ostrander also worked for two CPA firms, and directed audits of utility companies and other entities for the international accounting/auditing firm Deloitte, Haskins and Sells (now Deloitte).

Mr. Ostrander formed Ostrander Consulting in October 1990, after leaving employment as Chief of Telecommunications for the Kansas Corporation Commission. Ostrander Consulting has operated successfully and continuously for over 20 years through the present date and is in legal and ethical good standing in the U.S. and internationally.

Mr. Ostrander is also a licensed and practicing certified public accountant in Kansas and is required to meet strict industry ethics and practice requirements.

Mr. Ostrander's background experience started with the energy utility industry, when he performed annual audits, tax, and specialized services of Kansas Gas & Electric as a CPA employed by Deloitte. Subsequently, Mr. Ostrander became Chief Auditor at the KCC and much of his work focused on rate cases of telecommunications, gas and electric utilities. Mr. Ostrander was subsequently appointed as Chief of Telecommunication at the KCC, with a focus on telecom issues, although his expertise was periodically used in rate case audits of gas and electric utilities.

Mr. Ostrander has investigated matters related to all of the largest telecom carriers in the United States including, Verizon, AT&T, SBC/Southwestern Bell, U S WEST, Sprint, Embarq, BellSouth, MCI, numerous independent local exchange companies ("ILECs"), Relay Service Providers (provide telecom services to the speech and hearing impaired), and others. In addition, Mr. Ostrander has evaluated various other international telecom carriers, including Cable & Wireless.

Mr. Ostrander has addressed a broad range of regulatory issues including (but not limited to the following):

- ✓ Traditional Rate Cases
- ✓ Price Caps and Alternative Regulation Plans
- ✓ Specialized or Unique Accounting and Auditing Issues
- ✓ Audits of Universal Service Funds
- ✓ Virtually All Rate Case Expense Issues
- ✓ Virtually All Rate Base Issues
- ✓ Compensation Issues - Reasonableness of Base Salary, Incentives, and Perks
- ✓ Payroll Issues - Pro forma and normalized changes
- ✓ Outsourcing issues
- ✓ Affiliate Transactions
- ✓ Allocation of Costs between Regulated/Nonregulated Operations
- ✓ Depreciation Expense and Depreciation Rate Issues
- ✓ OPEB and Pension Expense Issues
- ✓ Dues and donations (EEI and AGA, etc.)
- ✓ Research and Development
- ✓ Promotions Expense
- ✓ Uncollectibles
- ✓ Rate Case Expense
- ✓ Charitable Contributions
- ✓ TIER issues
- ✓ REC Revenues
- ✓ Pipeline Assessment Costs
- ✓ Self-Insurance - Utility Company "insuring itself" for distribution/transmission losses
- ✓ Tree Trimming
- ✓ Legal costs and settlements
- ✓ Plant Held for Future Use
- ✓ Cash Working Capital (Lead/Lag Studies)
- ✓ Income Tax Issues
- ✓ Competition Issues
- ✓ Interconnection Issues
- ✓ Cost Accounting and Cost Allocation
- ✓ Access Deficit Issues in Caribbean Nations
- ✓ Universal Service Issues
- ✓ Local Loop Unbundling
- ✓ Licensing Issues
- ✓ Broadband/Internet Access and Infrastructure
- ✓ Tariff Policy and Design Issues

- ✓ Infrastructure Issues
- ✓ Facilities Sharing/Collocation Issues
- ✓ Service Quality Issues
- ✓ International Calling Prices and Competition
- ✓ Mobile/Cellular Calling Prices and Competition
- ✓ On-Net and Off-Net Pricing/Policy Issues in Caribbean Nations
- ✓ Issues Regarding Duopoly of Mobile Providers in Caribbean Nations
- ✓ Broadband Pricing and Competition Issues
- ✓ Number Portability Issues
- ✓ Purchase and Acquisitions (Debt, Finance and Regulatory Issues)
- ✓ Affiliate-Relationship Issues
- ✓ Cross-Subsidization Issues
- ✓ Parts 32, 36, 64 and 69 Issues

Work History- Ostrander

Ostrander Consulting – 1990 to Current (22 years):
Principal

Ostrander Consulting principally addresses regulatory issues on behalf of governments and regulatory agencies, including Attorney Generals and U.S. and international regulatory agencies. Services include those related to revenue requirement issues, price caps or alternative regulation plans, competition assessment, costing/pricing, interconnection/local loop unbundling, universal service, management audits and other matters.

Kansas Corporation Commission:
Chief of Telecommunications

Supervised staff and directed all telecommunications-related matters including assessment of rate cases of SWBT, United/Sprint and rural LECs. Also, directed actions regarding alternative regulation plans, establishing access charge policy, transition to intrastate competition, depreciation filings, establishment of the Kansas Relay Center, filings with the FCC, billing standards, quality of service, consumer complaints, staff training and over one hundred docketed regulatory matters per year. Mr. Ostrander was the lead witness on all major telecommunications matters.

Kansas Corporation Commission:
Chief Auditor

Directed rate cases of gas, electric and telecom companies prior to promotion to Chief of Telecommunications.

Mize, Houser, Mehlinger and Kimes (now Mize Houser & Company Professional Association):
Auditor – CPA firm

Performed auditing, tax and special projects for various industries.

Deloitte, Haskins and Sells (now Deloitte) – (International CPA/Audit Firm):
Auditor – CPA firm
Performed auditing, tax and special projects in industries such as utilities, savings and loan, manufacturing, retail, construction, real estate, insurance, banking and not-for-profit.

Education- Ostrander

University of Kansas - B.S. Business Administration with a Major in Accounting, 1978.

Professional License and Affiliations - Ostrander

- Maintains a permit to practice as a CPA in Kansas.
- Member of the American Institute of CPAs (AICPA).
- Member of the Kansas Society of CPAs (KSCPA).

Recent Experience (10 Years) – Major Cases – Bion C. Ostrander

2012 – Baltimore Gas and Electric – Before the Public Service Commission of Maryland - Case 9299: Mr. Ostrander reviewed most operating expense revenue requirement issues, including payroll, benefits/OPEB, deferred compensation, merger costs and savings, RM 43 and 44 plant and expenses, rate case expense, taxes, injuries and damages, tree trimming/vegetation management, and other expenses.

2012 – Potomac Electric Power Company – Before the Public Service Commission of Maryland - Case 9286: Mr. Ostrander reviewed most operating expense revenue requirement issues, including payroll, benefits/OPEB, deferred compensation, uncollectibles, rate case expense, taxes, injuries and damages, expenses incurred for complying with Commission's service quality directive, tree trimming/vegetation management, and other expenses.

2012 – Delmarva Power and Light Company – Before the Public Service Commission of Maryland - Case 9285: Mr. Ostrander reviewed most operating expense revenue requirement issues, including payroll, benefits/OPEB, deferred compensation, uncollectibles, rate case expense, taxes, injuries and damages, expenses incurred for complying with Commission's service quality directive, tree trimming/vegetation management, and other expenses.

2011 - Washington Gas Light – Before the Public Service Commission of Maryland - Case 9267: Mr. Ostrander reviewed all revenue requirement issues including a detailed review of the complicated outsourcing arrangement with Accenture, long-term incentives, other payroll issues, research & development, pipeline assessment costs, various rate base additions, and other issues. Mr. Ostrander pre-filed three sets of testimony and appeared as a witness for the Maryland Office of People's Counsel.

2012/2011 - PacifiCorp – Before the Washington Utilities and Transportation Commission - Docket UE-111190: Mr. Ostrander pre-filed testimony for certain revenue requirement issues including various accounting adjustments, payroll issues, "self-insurance" for transmission & distribution assets, management fees charged from Corporate to the regulated utility, and other matters for the Washington State Attorney General's Office - Public Counsel Section.

2011 – Review of the Revenue Requirements of Washington Electric Cooperative, Inc. (WEC) - Docket No. 7691 before the Vermont Public Service Board: Mr. Ostrander performed this work for the Vermont Department of Public Service, reviewing the revenue requirements, adjustments, TIER, affiliate transactions issues, and other related issues of WEC.

2012 - Docket No. 12-GIMT-170-GIT - before the Kansas Corporation Commission – Mr. Ostrander represents the Citizens' Utility Ratepayer Board of Kansas (CURB) in this proceeding to address the impacts that the FCC's Omnibus Order (issued November 2011) regarding Federal Universal Service, Connect American Fund (broadband USF and mobility fund), intercarrier compensation, lifeline, separations reform, cost models, and other related issues could have on the Kansas USF (KUSF). In addition, the KUSF is being reviewed for policy changes that could impact the fund and related annual assessments.

2011 – Docket No. 11-GIMT-420-GIT (Docket 420) - before the Kansas Corporation Commission – This docket was initiated in 2010. Mr. Ostrander represents the Citizens' Utility Ratepayer Board of Kansas (CURB) in this proceeding to address changes in policy and review of cost studies to determine cost-based Kansas Universal Service Fund support for price capped telecom carriers. This costs of universal service included in the KUSF have not been reviewed in over ten years for these carriers, and this docket will evaluate those costs and other policy issues.

2008 – 2010 - Docket No. 08-GIMT-1023-GIT (Docket 1023) – before the Kansas Corporation Commission – This docket was initiated May 2008 and essentially completed June 2010. Mr. Ostrander worked on this case from beginning to end for CURB. In this proceeding, Sprint filed a petition to reduce CenturyLink's intrastate access charges to the interstate level (mirror interstate access). There were differences of opinion regarding interpretation of language in existing Kansas statute regarding how often, and when, mirroring of interstate access charges is required for mid-sized carriers like CenturyLink (CL). CL's intrastate access rates had previously been reduced to interstate levels in 1997/1998, 2000, and 2002, and Mr. Ostrander participated in all of these proceedings. In these prior cases, part of the access charges were rebalanced to increases in basic local rates and discretionary services, and the remainder was included in the KUSF. The current proceeding rebalancing the entire difference between intrastate and interstate access rates to the KUSF, and there were no increases in any other rates of CL. There will continue to be similar proceedings in the future for periodic updates to interstate access rates.

Mr. Ostrander's responsibilities in Docket 1023 included:

- Perform analysis
- Prepare discovery and review responses to all discovery
- Prepare direct and rebuttal testimony
- Participate as a witness in hearings
- Participate in negotiations with Sprint and CenturyLink regarding the flow-through of access reductions to retail rates.

2010 - Docket No. 10-GIMT-188-GIT – (Docket 188) - before the Kansas Corporation Commission – This docket was addressed by Mr. Ostrander from June to October 2010. Mr. Ostrander reviewed Staff's testimony and calculations and no problems were identified. Hearings were not held in this proceeding because no problems or issues were identified. Kansas statute requires rural LEC access rates to update their intrastate access rates to interstate levels every 2 years, with the difference between intrastate and interstate rates included in the KUSF. Mr. Ostrander has reviewed calculations and participated in these proceedings for the past 14 years during the existence of the KUSF.

1999 to 2010 – Kansas Universal Service Fund (KUSF) Calculations and Competitive Impact – Kansas: On behalf of the Citizens' Utility Ratepayer Board of Kansas, Mr. Ostrander has addressed the calculation of KUSF assessments for each of the 14 years of the fund, including the evaluation of the projected gross revenue base, safe harbor percentages for wireless and VoIP providers, the treatment of VoIP revenues, withdrawals from the fund, statutory compliance, internal control procedures, and evaluation of competitive data and analysis submitted by carriers to ensure that assessments to consumers are reasonable and within the proper guidelines.

2009 – Review KCPL Iatan Coal Plant Charges - Docket No. 09-KCPE-246-RTS before the Kansas Corporation Commission: Mr. Ostrander represented the Citizens' Utility Ratepayer Board (CURB) in Kansas. Mr. Ostrander made numerous on-site inspections of the Iatan 2 Coal Plant of Kansas City Power & Light in order to address percent completion and in-service dates of environmental upgrades and other construction, which affects treatment in the related rate case. Errors were detected in the control budgets and allocation of common costs between Iatan units 1 and 2, KCP&L failed to comply with FERC guidelines regarding treatment of common costs, and it became necessary to analyze plant and separate the common costs between Units 1 and 2 in order to make sure such costs were not double-counted on KCP&L's books (and in rate base).

2002 to 2010 - Evaluation of the Intrastate IntraLATA/InterLATA Embedded Cost of Service of Various Alaska Rural LECs for Purposes of Establishing Annual Access Charge Rates - Alaska: For this nine year period, Mr. Ostrander evaluated the embedded costs of the intrastate jurisdiction (intrastate intraLATA/interLATA revenue requirement) of rural LECs in Alaska (using a traditional rate case approach) for purposes of establishing intrastate access charge rates in Alaska each year.

2010 - Evaluate Rural LEC Request for Increased Universal Service Fund Disbursements: On behalf of the Citizens' Utility Ratepayer Board, Mr. Ostrander determined that a rural LEC did not properly meet the filing requirements for expedited withdrawals from the Kansas Universal Service Fund (KUSF), and the company will re-file a traditional rate case in future months. Mr. Ostrander may participate in that future proceeding when it is filed.

2009 to 2010 - ECTEL - Evaluate Competition and Implement Price Caps Plan: On behalf of the Eastern Caribbean Telecommunications Authority (the centralized regulatory agency representing the Caribbean nations of St. Lucia, St. Vincent, Grenada, St. Kitts/Nevis, and Dominica), Mr. Ostrander completed an evaluation of competition, assessment of duopoly market, access deficit issues raised by the incumbent carrier, pricing/costing issues, imputation, impact of the initial price cap plan, retail prices for international, mobile, internet and local service, wholesale interconnection prices, financial operations of the incumbent, and infrastructure issues. Interviews were conducted with the various stakeholders and a detailed consultation process was used for gathering and assessing information from various stakeholders. All of these issues were considered in recommending the implementation of a new price cap plan for the ECTEL member nations.

2009 - 2010 - Evaluate Access Costs, Rebalance to Kansas Universal Service Fund, and Related Policy for Major Carriers - Kansas: On behalf of the Citizens' Utility Ratepayer Board of Kansas, Mr. Ostrander recently completed assessment of policies and evaluating costs/pricing for intrastate interconnection/access between the largest carriers in Kansas and other competitive carriers. Also, the calculation of proper amounts to be rebalanced and included in the Kansas Universal Service Fund were addressed. Mr. Ostrander also addressed universal service and the impacts of rate rebalancing proposals by Embarq, Sprint and AT&T.

2010 – Evaluate Access Charges for Rural Telephone Companies - Kansas: On behalf of Citizens' Utility Ratepayer Board of Kansas, Mr. Ostrander will address costing, legal, and policy issues related to interconnection/access charges for rural telephone companies in Kansas (after previously addressing this same issue for the largest carriers in Kansas). The interconnection aspects relates to the cost of the local service carrier providing access to its public switched network and facilities so that other carriers can provide competitive long distance/other services.

February 2009 to June 2009, USAID Capacity Assessment and Development for the Department of Public Services Regulatory Commission of Armenia: Mr. Ostrander assisted with this project to conduct a telecom sector strategic analysis, legal and regulatory assessment, and human and institutional capacity assessment for the PSRC in Armenia, under the auspices of USAID and the Academy for Educational Development. The team consisted of three experts from the US, and local experts in Armenia. The team delivered a comprehensive Final Report to AED and USAID on May 31, 2009, which addressed government's plan for IT sector development, market structure and technological potential, the current telecommunications
law and regulatory environment, current regulatory performance and priorities, overlapping responsibilities, performance gaps, and human and institutional capacity assessment regarding areas including independence, accountability, transparency, institutional characteristics, organizational structure, and financing and budget.

2008 to 2010 – Evaluate Competition/Price Caps/Tariffs - Maryland: On behalf of the Maryland Office of Public Counsel (regulatory agency), Mr. Ostrander addressed competition, costing/pricing issues, tariff policy, universal service, preservation of reasonable prices for low income citizens, infrastructure issues related to fiber/DSL and other financial matters that impacted the recommendation of a new price cap plan applicable to Verizon Maryland (the dominant incumbent carrier).

1999 to Current – Universal Service Fund Calculations and Competitive Impact – Kansas: On behalf of the Citizens' Utility Ratepayer Board (CURB) of Kansas, Mr. Ostrander has addressed the calculation of Kansas Universal Service Fund (KUSF) assessments for each of 11 years of the operation of KUSF, including the evaluation of competitive data and analysis submitted by carriers and ensuring that assessments to consumers are reasonable and within the proper guidelines.

2009/2008 - Verizon Michigan Cost Studies and Competitive Impact: On behalf of the Michigan Attorney General (regulatory agency), Mr. Ostrander addressed cost studies for the retail cost of basic local service and the wholesale cost of local service (local loop unbundling), identified problems with Verizon Michigan (incumbent carrier) cost studies, and evaluated the related impacts on competition and universal service.

2008/2007 - Cable & Wireless (C&W) Barbados Price Caps and Competition: On behalf of the Fair Trading Commission (FTC) of Barbados (the regulatory agency in Barbados), Mr. Ostrander addressed a new price cap plan for C&W, policy related to competition, cost of regulated/deregulated services, international calling rates, cost allocation matters, tariff issues, and infrastructure matters.

2008/2007 - Price Caps and Competition Impacts for AT&T and Embarq – Kansas: On behalf of the Citizens' Utility Ratepayer Board of Kansas, Mr. Ostrander addressed price caps and related impacts upon competition as it relates to the carriers AT&T and Embarq in Kansas.

2007 - UNE Costing Embarq Nevada: On behalf of the Nevada Bureau of Consumer Protection-Attorney General, Mr. Ostrander addressed unbundled network elements (local loop unbundling).

2007 - Legislation/Deregulation and Competitive Impacts - Embarq Nevada: On behalf of the Nevada Bureau of Consumer Protection-Attorney General, Mr. Ostrander addressed Legislative issues regarding competition, deregulation and pricing flexibility related to Embarq.

2007 – Affordable Local Rates – Michigan: On behalf of the Michigan Attorney General, Mr. Ostrander addressed Verizon's failure to file proper tariffs to comply with Michigan law regarding affordable rates for basic local telephone service.

2007 – RTB – Alaska: On behalf of GCI, Mr. Ostrander addressed the issue of the proper treatment of funds received by telephone companies related to the dissolution of the Rural Telephone Bank (RTB).

2007 – Verizon Deregulation – Virginia: On behalf of the CWA, Mr. Ostrander addressed Verizon's request for deregulation and detariffing in Virginia and related competition issues.

2007 - 2005 – Verizon Maine: On behalf of AARP, Mr. Ostrander addressed the revenue requirements of Verizon Maine, including issues such as Yellow Pages, affiliate transactions and DSL-related issues.

2007 - 2008 Legislative Kansas: Assisted CURB in Kansas with 2007 legislative issues related to telecom, competition and other matters.

2006/2005 – Embarq/LTD & Sprint/Nextel Change of Control – Kansas: On behalf of CURB of Kansas, Mr. Ostrander evaluated the separation and creation of a new local service holding company and the potential impact on customers, rates, competition, service quality and other issues.

2006 – Embarq Sale of Exchanges to Rural Telephone – Kansas: On behalf of CURB of Kansas, Mr. Ostrander reviewed Embarq's sale of local exchanges to Rural Telephone Company and addressed issues such as rates, due diligence, service quality, acquisition adjustments, tariff design, competition and policy issues.

2006/2005 – Verizon & AT&T Local Rate Rebalance – Michigan: On behalf of the Michigan Attorney General, Mr. Ostrander reviewed the requests of Verizon and AT&T to rebalance and increase local rates, including the necessity to preserve affordable and reasonable local rates.

2006 – Embarq Proposal to Reduce MetroPlus Rates as a Competitive Response – Kansas: On behalf of CURB, Mr. Ostrander reviewed Embarq's proposal to significantly reduce its charge for MetroPlus service as a response to competition in several of its exchanges.

2006/2005 – ETC Policy in Kansas – Kansas: Mr. Ostrander assisted CURB with comments regarding the establishment of state policy and filing requirements for Eligible Telecommunication Carriers (ETCs) in Kansas, while also considering the FCC's related policy and requirements. Mr. Ostrander addressed these issues in three separate generic dockets (06-GIMT-446-GIT, 06-GIMT-082-GIT and 05-GIMT-112-GIT) before the Kansas Corporation Commission.

2006 – United Telephone (now Embarq) Sale of Exchanges to Twin Valley – Kansas: On behalf of CURB, Mr. Ostrander reviewed United Telephone's sale of local exchanges to Twin Valley Telephone Company and addressed issues such as rates, service quality, acquisition adjustments, tariff design, competition and policy issues.

2006 – Kansas Universal Service Fund (KUSF) Assessment – Kansas: On behalf of CURB, Mr. Ostrander evaluated the Kansas Universal Service Charge annual calculation and assessment.

2006/2005 – Unsubstantiated Rate Additives by CLECs – Kansas: On behalf of CURB, Mr. Ostrander has addressed issues related to excessive and unsubstantiated recurring charges Placed on telephone bills by CLECS such as Sage, CIMCO, ITC/DeltaCom, etc.

2005 – United Telephone (now Embarq) Sale of Exchanges to Blue Valley – Kansas: On behalf of CURB, Mr. Ostrander reviewed United Telephone's sale of local exchanges to Blue Valley Telephone Company and addressed issues such as rates, due diligence, service quality, acquisition adjustments, tariff design, competition and policy issues.

2005 – Saudi Arabia Communications and Information Technology Commission (CTIC): Assessed Saudi Telecom's proposed accounting separation and allocations manual on behalfof the CITC.

2005 – Embarq/LTD & Sprint/Nextel Change of Control – Nevada: On behalf of the Nevada Board of Consumer Protection, Mr. Ostrander evaluated the separation and creation of a new local service holding company and the potential impact on customers, rates, service quality and other matters.

2001 – 2003 - Kansas Gas & Electric Rate Case - Docket No. 01-WSRE-436-RTS before the Kansas Corporation Commission: Mr. Ostrander represented the Citizens' Utility Ratepayer Board (CURB) in Kansas. In this electric utility rate case, Mr. Ostrander filed testimony and appeared as a witness. Mr. Ostrander addressed issues and adjustments related to proper cost allocation policy and procedures, including the correct allocation of executive and corporate compensation, taxes, Board of Director fees, insurance, building cost, and software. In addition, he addressed the company's improper accounting treatment of restricted shares and dividend benefits to executives, and adjustments related to professional services expenses. Also, Mr. Ostrander reviewed the company's internal aircraft logs and used this information to allocate additional executive payroll costs to nonregulated operations based on extensive use of the company's aircraft for both nonregulated operations and personal use by company executives, their families, and associates.

2005/2004 – Verizon Vermont: On behalf of the Vermont Department of Public Service, Mr. Ostrander evaluated Verizon Vermont's revenue requirements, Yellow Pages, affiliate transactions, work force reductions, depreciation issues, infrastructure/modernization, and policy issues as part of a new alternative regulation plan ("ARP") to go in place in 2005, after the expiration of the current plan. Mr. Ostrander previously conducted an earnings review and evaluation of the prior ARP five years ago in Vermont.

2005 - Southwestern Bell Kansas: On behalf of CURB, Mr. Ostrander assisted with the review of SWBT's request for deregulation of local and other services in certain metro exchanges.

2005/2004/2003 – Cable & Wireless Barbados ("C&W"): On behalf of the Fair Trading Commission ("FTC"), the regulatory agency in Barbados), Mr. Ostrander evaluated a proposal by C&W in 2003/2004 to move away from flat-rate local service to introduce "measured or usage-based" local service at increased rates, as well as policy issues to expand cellular competition and other competition issues. Mr. Ostrander addressed the revenue requirements of C&W, proposed significant revisions to these revenue requirements, and reviewed the C&W cost model and the costs of local, cellular, and other services. The FTC's final decision in July 2004 rejected the C&W proposal, and maintained local rates at existing levels without a switch to measured service.

2004/2003 – Cable & Wireless Eastern Caribbean States: On behalf of the Eastern Caribbean Telecommunications Authority ("ECTEL"), the regulatory agency for certain Caribbean nations), and the nations of St. Lucia, Grenada, St. Vincent, St. Kitts/Nevis, Mr. Ostrander evaluated implementation of the first price caps plan, policy to introduce and expand cellular and other competition in these Caribbean nations, reviewed C&W cost models, evaluated the cost of fixed local and cellular service, as well as other issues. This project resulted in substantial regulatory concessions to customers and significant reductions in prices and increases in infrastructure investment by competitors.

Kentucky Office of Attorney General
Summary of TIER Revenue Requirements and OAG Adjustments
Big Rivers Electric Corporation - Case No. 2012-00535
Adjusted Forecasted Test Period

Exhibit BCO-2
Schedule A-1

A	B	C	D	E	F	G
Line No.	Description	BREC Orig. Filing	OAG Direct	Adj. No.	Adj. Description	OAG Adjustments
					OAG Operating Adjustments:	
1	*Operating Revenues*	355,554,623	355,554,623	OAG-1-DB	Remove Century smelter lost margins	($63,028,536)
2	Operating Expenses	376,347,350	376,347,350	OAG-2-BCO	Adjust Officer and Management Compensation	($2,364,579)
3	Int. Exp. on LT Debt	46,983,291	46,983,291	OAG-3-BCO	Impact of rehearing rate relief, corrections, etc.	($1,568,516)
4	**Total Cost of Electric Service**	423,330,641	423,330,641	OAG-4(c)-BCO	July 2012 re-finance RUS note - amortize cost	$133,841
5	**Gross Operating Margin**	$ (67,776,018)	$ (67,776,018)	OAG-5-BCO	Reduce current rate case expense	($342,643)
6	Other Non-operating income	$ 4,681,304	4,681,304	OAG-6-BCO	Adjust percent of payroll expensed to historical levels	($555,308)
7	Net Margin	$ (63,094,714)	(63,094,714)			
8						
9	**ADJUSTMENTS:**					
10	OAG Adjustments - Int. Exp. on LT Debt		1,616,476			
11	OAG Adjustments - Gross Margin		$ 67,725,741		**Total Operating Adjustments**	**($67,725,741)**
12	**OAG Adjusted Operating Margin**	$ (67,776,018)	$ 1,566,199			
13					**OAG Non-Operating Adjustments:**	
14	KYOAG Adjustments - Non-operating		$ 2,706,448	OAG-4(b)-BCO	July 2012 re-finance RUS note - patronage alloc	($2,706,448)
15	**KYOAG Adjusted Net Margin**	$ (63,094,714)	$ 8,953,951			
	nterest income on reserve	$ (105,415)	$ (105,415)			
	OAG Adjustments - Int. income on res.					
19	Adjusted Int. Income on Reserve	$ (105,415)	$ (105,415)		**Total Non-Operating Adjustments**	**($2,706,448)**
20	Margin calculation for TIER (deduct Int. Inc.)	$ (63,200,129)	$ 8,848,536			
21					**OAG Interest Expense Adjustments:**	
22	Unadjusted Actual TIER (deduct Reserve income)	-0.35	1.20	OAG-4(a)-BCO	July 2012 re-finance RUS Note	($1,616,476)
23	*Unadjusted Actual MFIR (include Reserve income)*	-0.34	1.20			
24						
25	Contract Smelter TIER Required (Note 1)	1.24	1.24		**Total Interest Expense Adjustments**	**($1,616,476)**
26	Loan Agreement MFIR Required (Note 1)	1.10	1.10			
27					**OAG Interest Income on Reserve Adjs.**	
28	Margins Required for Smelter TIER 1.24	$ 11,381,405	$ 10,993,451			$0
29	Revenue Required for Smelter TIER 1.24	$ (74,476,119)	$ (2,039,500)	Note 2		
30	**Required Revenue Increase - TIER 1.24**	$ 74,476,119	$ 2,039,500			
31					**Total Interest Income on Reserve Adjs.**	**$0**
32	Margins Required for Loan Covenant MFIR 1.10	$ 4,698,329	$ 4,536,682			
33	Revenue Required for Loan Covenant MFIR 1.10	$ (67,793,043)	$ 4,417,270		**Total OAG Adjustments above**	**($72,048,665)**
34	**Required Revenue Increase - MFIR 1.10**	$ 67,793,043	$ (4,417,270)		**Brevitz sponsored adjustments**	**($63,028,536)**
35					**Ostrander sponsored adjustments**	**($9,020,129)**
36	**Difference between 1.24 and 1.10 TIER**	$ (6,683,076)	$ (6,456,769)		**Total OAG Adjustments**	**($72,048,665)**
37						

40 Note 1 - TIER and MFIR Calculation:
41 Smelter Contract TIER 1.24 = Margin + Int. Exp. on LT Debt/Interest Exp. on LT Debt. Per Section 4.7.5(f)of Smelter Agreements, interest income on Reserve funds
42 must be adjusted out of the TIER calculation (BREC response to KIUC DR 1.53(c).
43 Loan Agreement MFIR 1.10 = Margin + Int. Exp. on LT Debt + Income Taxes/Int. Exp. on LT Debt (This calculation is same as TIER calculation because BREC has no income taxes).
44 However, interest income on Reserve funds are retained in the calculation of the MFIR/TIER (BREC response to KIUC DR 1.53(c).
45 Note 2 - TIER calculation method same as Exhibit Wolfram-2, page 2 of 14.

Kentucky Office of Attorney General
Remove Century Margins
Big Rivers Electric Corporation - Case No. 2012-00535
Adjusted Forecasted Test Period

Exhibit BCO-2
Schedule A-2
Adj. OAG-1-DB

A	B	C	D
Line No.	Century Smelter Impact	OAG Adj.	Source
1	**Adj. OAG-1-DB**	**63,028,536**	Note 1
2	Note 1: Source is Exhibit Berry-4, page 1 of 1.		

Kentucky Of[illegible] Attorney General

Remove Office[illegible]Management Excessive Salary Increases and Proposed Pay Raises — **Exhibit BCO-2**

Big Rivers Electric Corporation - Case No. 2012-00535 — **Schedule A-3, page 1 of 3**

Adjusted Forecasted Test Period — **Adj. OAG-2-BCO**

A	B	C	D	E	F	G	H	I	J	K
	OAG ADJUSTMENT SUMMARY:		Base	Forecasted	Adjusted					
No.			Period	Test Period	Total		Comment			
1	**Remove significant/unsupported pay increases for Officers, Management and NonManagement (No Union) after Unwind Case:**									
2	M. Bailey - President and CEO	see below		188,667	(188,667)	BREC only reports two Company Officers				
3	R. Berry - VP Production	see below		126,211	(126,211)	BREC only reports two Company Officers				
4	C. Blackburn - Sr. VP and CFO					Retired in 2012				
5	**Adjustment - Officers**				(314,878)	OAG-2(a)-BCO				
6	**Adjustment for Management/Nonmanagement**				(1,129,395)	OAG-2(a)-BCO				
7	**Total Adjustment**				**(1,444,273)**	**OAG-2(a)-BCO**				
8	**Remove future pay increases not known and measurable (performance/employment unknown):**									
9			Base Period	Forecasted						
10	% Pay Increase		2.25%	2.25%						
11	**Non-bargaining**	PSC 1-34	470,802	449,504	**(920,306)**	**OAG-2(b)-BCO**				
12	**TOTAL PAYROLL ADJUSTMENT OAG-2-BCO**				**(2,364,579)**	**OAG-2-BCO**				
13	**Mark Bailey - President and CEO:**	Source	Pay	Other	Incentive	Retention	SERP	Total	Adjustment	
14	FTP- end Aug. 31, 2014 - payroll	Tab 53	542,308	18,000	-	-	-	560,308		**18,000**
15	FTP - end Aug. 31, 2014 - payroll increase		16,001	-				16,001	Adjusted at part (b)	
16	FTP - % Increase		3.04%							
17	Base Period - end April 30, 2013 - payroll	Tab 53	526,307	18,000	-	-	-	544,307		
18	Base Period - end April 30, 2013 - payroll increase		4,067					4067	Adjusted in part (b)	
19	Base Period - % Increase		0.78%							
20	2012- payroll	PSC 1-40	522,240					522,240	Note 4	
21	2012 - payroll increase	PSC 1-40	0					0	Note 4	
22	2012 - % Increase	PSC 1-40	0					0	Note 4	
23	2011 - payroll	PSC 1-40	522,240					522,240	Note 4	
24	2011 - payroll increase	PSC 1-40	10,240					10,240	Note 4	
25	2011 - % Increase	PSC 1-40	2.00%						Note 4	
26	2010 - payroll (Note 3)	PSC 1-40	512,000					512,000	Note 4	
27	2010 - payroll increase	PSC 1-40	-						Note 4	
28	2010 - % Increase	PSC 1-40	**0%**						Note 4	
29	2009- payroll		512,000					512,000		
30	2009 - payroll increase (Note 1)	AG-253(b)	**170,667**					170,667		**170,667**
31	2009 - % Increase (Note 1)	AG-253(b)	**50%**							
32	**BAILEY TOTAL ADJUSTMENT**									**188,667**
33										
34	**Robert W. Berry - VP Production:**									
35	FTP- end Aug. 31, 2014 - payroll	Tab 53	293,418	8,811	10,000	-	-	312,229		**18,811**
36	FTP - end Aug. 31, 2014 - payroll increase		8,657	-				8,657	Adjusted at part (b)	
37	FTP - % Increase		3.04%							
38	BP - end April 30, 2013 - payroll (Note 2)	Tab 53/PSC 1	284,761	8,337	155,631	-	-	448,729		
39	BP - end April 30, 2013 - payroll increase		2,201					2201	Adjusted in part (b)	
40	BP - % Increase		0.78%							
41	2012- payroll	PSC 1-40	282,560					282,560	Note 4	
42	2012 - payroll increase	PSC 1-40	7,160					7160	Note 4	
43	2012 - % Increase	PSC 1-40	2.60%					0.025998548	Note 4	
44	2011 - payroll	PSC 1-40	275,400					275,400	Note 4	
45	2011 - payroll increase	PSC 1-40	65,400					65,400		**65,400**
46	2011 - % Increase	PSC 1-40	31.14%						Note 4	
47	2010 - payroll (Note 3)	PSC 1-40	210,000					210,000	Note 4	
48	2010 - payroll increase	PSC 1-40	-						Note 4	
49	2010 - % Increase	PSC 1-40	**0%**						Note 4	
50	2009- payroll		210,000					210,000		
51	2009 - payroll increase (Note 1)	AG-253(b)	**42,000**					42,000		**42,000**
52	2009 - % Increase (Note 1)	AG-253(b)	**25%**							
53	**BERRY - TOTAL ADJUSTMENT**									**126,211**

	OAG 1-75(a)	
Management & Nonmanagement	Payroll	Reference
Total Exempt labor - FTP	19,695,793	Exh. BCO-2, Sch. A-7, CoL. E, line 1.
Deduct: Officer's FTP payroll above	(872,537)	
Net payroll subject to pay increases	18,823,256	
Remove 6.48% of pay increases	6.00%	Note 5
Remove large Exempt pay increases	**1,129,395**	**OAG-2-BCO**

Kentucky Office of Attorney General
Remove Officer/Management Excessive Salary Increases and Proposed Pay Raises
Big Rivers Electric Corporation - Case No. 2012-00535
Adjusted Forecasted Test Period

Exhibit BCO-2
Schedule A-3, page 2 of 3
Adj. OAG-2-BCO

No.	Notes to Exhibit BCO-2, Schedule A-3, page 1 of 2.
1	Note 1 - BREC claims it cannot provide payroll data for 2009 and prior years per PSC 1-32, so the % increase was estimated using the
2	average increase of 48% for 2009 for Officers (the range of increase was 14.75% to 69.58% for Officers) per OAG 1-253(b).
3	Note 2 - Tab 53 and PSC 1-40 differ slightly in amounts reported, amount from Tab 53 is used here.
4	Note 3 - BREC would not identify the amount of Retention Bonus paid in total or by employee in July 2010 (1 year after the Unwind Case), per AG 2-56.
5	Note 4 - PSC 1-40 only appears to report total compensation, without reporting individual components such as incentives, etc.
6	Note 5 - OAG 1-253(b) reports the following higher pay increases - Management average pay increases of 6.40% in 2009 and 7.08% in 2011,
7	and Non-Management pay increases were 4.56% in 2009. This adjustments would normally remove about 5% of the 2009 pay increases
8	(of total 9.96% in 2009) plus 3% of pay increases in 2011 - - for a total decrease of about 8% that is included in FTP payroll.
9	To make this adjustment conservative, only 6% will be removed. Because total payroll costs were presumably greater in 2009 than in the forecasted
10	test period for which amounts are being removed, this should balance out so that excessive amounts are not removed.

Kentucky Office of Attorney General
Significant Payroll Increases Substituted for Deferred Maintenance Exhibit BCO-2
Big Rivers Electric Corporation - Case No. 2012-00535 — **Schedule A-3, page 3 of 3**
Adjusted Forecasted Test Period — **Adj. OAG-2-BCO**

A	B	C	D	E	F	G	H	I
No.	Significant Pay Increases	Unwind Order 2009	2010	2011	2012	Base Period	Forecast Test Period	Total
1	Pay increases in year of Unwind	$1.4 m						$1.4 m
2	Retention bonus -1 year after Unwind		$1.0 m					$1.0 m
3	Various incentives/bonuses			$1.1 m				$1.1 m
4	Various incentives/bonuses				$.7 m			$.7 m
5	Incentives					$.2 m		$2. m
6	Incentives						$.04 m	$.04 m
7	**Total Signficant Pay Increases**							**$4.4 m**

8

	Officers/Management/NonManagement (No Union Employees)	Employee	Forecast Test Period	Base Period	2012	2011	2010	Unwind 2009	Total
11	Significant Increases in Base Pay After Unwind Case	Bailey and Berry (a)				$75,640	$0	$212,667	$288,307
12	Significant Increases in Base Pay After Unwind Case	Management (b)	$0	$0	$0	$0	$0	$1,129,395	$1,129,395
	Significant Increases in Base Pay After Unwind Case	Blackburn - Retired	$0	$0	$0	$60,600	$0	$42,000	$102,600
	Significant One-Time Incentives	Various - (c)	$36,811	$181,968	$644,193	$926,107		not provided	$1,789,079
15	Significant Bonuses	Various - (d)			$32,648	$33,586		not provided	$66,234
16	Significant SERP	Various - (d)			$20,890	$20,858		not provided	$41,748
17	Retention Pay 1 Year After Unwind Case (July 2010)	Various - (e)					$1,000,000		$1,000,000
18	**Significant Pay Increases In Place of Deferred Maintenance**		$36,811	$181,968	$697,731	$1,116,791	$1,000,000	$1,384,062	**$4,417,363**

19

20 Note: This schedule does not include all pay raises from year to year, only those that are significant, paid immediately after the Unwind Case, and other
21 one-time nonrecurring pay increases.
24 (a) - Significant increases in Officer base pay in 2009 after Unwind Case were an average of 48% (range of 14.75% to 69.58%), but BREC would not provide
25 specific pay increases for each Officer per response to OAG 1-253(b), so amounts were estimated.
26 (b) - Significant increases in Management/Non-Management base pay (not include Union employees) mostly in 2009 and 2010, although amounts
27 were allocated to 2009 for simplifying this table (after Unwind Case) and were an average of 5% to 7%), but BREC would not provide specific pay increases
28 pay increases by Management per OAG 1-253(b), so amounts were estmated.
29 (c) - Relates to various Officers and Management Employees, but not all identified by employee - Att. 53 Haner, pages 1 to 3, plus response to OAG 1-76.
30 (d) - Relates to various Officers and Management Employees, but not all identified by employee - response to OAG 1-76.
31 (e) - The response to AG 1-78 states the Retention Bonuses were paid one year after the Unwind Case (July 2010), but BREC would not provide the
32 amounts paid so this is an estimate using about 5% of total Management payroll (without benefits).

Kentucky Office of Attorney General
Corrections to Include Commission's Rate Relief Order and Other BREC Corrections
Big Rivers Electric Corporation - Case No. 2012-00535
Adjusted Forecasted Test Period

Exhibit BCO-2
Schedule A-4
Adj. OAG-3-BCO

A	B	C
No.	Corrections	Amounts
1	BREC Proposed Change	1,507,989
2	**OAG Proposed Change and Adjustment**	**1,568,516**
3	Note 1	**Adj. OAG-3-BCO**

4 Note 1 - See Ostrander Direct Testimony for explanation

Kentucky Office of Attorney General
Cost Savings Related to July 2012 Refinancing of RUS Series A Note
Big Rivers Electric Corporation - Case No. 2012-00535
Adjusted Forecasted Test Period

Exhibit BCO-2
Schedule A-5
Adj. OAG-4-BCO

A	B	C	D
No.	Description	Adj.	Source
1	Series A Note refinancing ($440,771,549*1.43%)	(6,303,033)	AG DR 1-63(c)
2	Additional borrowing ($96,228,451*4.41%)	4,243,675	AG DR 1-63(c)
3	Int. expense CTC loan	2,214,409	AG DR 1-63(c)
4	Int. income CTC investment	(1,771,527)	AG DR 1-63(c)
5	**OAG-4(a)-BCO - Int. Expense Adjustment**	**(1,616,476)**	
6			
7	**OAG-4(b)-BCO - Estimated Patronage Allocation Adjustmen**	**(2,706,448)**	AG DR 1-63(c)
8			
9	Amortized loss on reacquired RUS Series A Note	60,482	AG DR 1-63(c)
10	Amortize refinancing cost	73,359	AG DR 1-63(c)
11	**OAG-4(c)-BCO - Amortized Loan Adjustment**	**133,841**	
12			
13	**Total Impact of Cost Savings from Loan Refinancing**	**(4,189,083)**	
14			
15	Note: This adjustment is related to refinancing addressed in Case No. 2012-00119		

Kentucky Office of Attorney General
Current Rate Case Expense — **Exhibit BCO-2**
Big Rivers Electric Corporation - Case No. 2012-00535 — **Schedule A-6**
Adjusted Forecasted Test Period — **Adj. OAG-5-BCO**

A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
				BREC Current Rate Case Expense per PSC 1-54 (Note 1)					**PSC 1-54**							
				Costs for Jly. - Nov. '12 1st DR - Jan. 29th	Costs for Dec. '12 1st update - Feb. 15th	Costs for Jan. '13 2nd update - Mar. 18th	Costs for Feb. '13 3rd update - Apr. 19th	**Total Actual Incurred**	Total Estimated Rate Case	**Percent Expenses Not Incurred**	Allowed			Not Allowed		
No.	Vendor	Srv.	Nt.	Actual Incurred				**to Date**	Expense	**to Date**	Actual	Estimated	Total	Actual	Estimated	Total
	Non-Legal:															
1	Catalyst Consulting	a	2	69,147	33,955	23,830	45,134	172,066	411,255	58%	172,066	27,934	200,000	0	211,255	**211,255**
2	Burns and McDonnell	b		31,663	10,637	-		42,300	100,297	58%	42,300	7,997	50,297	0	50,000	**50,000**
3	American Man. Con.	c		2,065	-	-		2,065	-		-		-	2,065	-	**2,065**
4	Aces Power Marketing			-	-	-		-	42,940	100%	-		-	0	42,940	**42,940**
5	Other ($55,785)		3	-				-	55,785	100%	-		-	0	55,785	**55,785**
6	Dan Walker				5,750		2,000	7,750	-		7,750		7,750			-
7	**Subtotal Non-Legal**			102,875	50,342	23,830	45,134	**222,181**	**610,277**	**64%**	222,116	35,931	**258,047**	2065	359,980	**362,045**
8																
9	**Legal:**															
10	Sullivan, Mountjoy	d		53,373	27,388	41,980	41,694	164,435	454,620	64%	164,435	(14,435)	150,000		304,620	**304,620**
11	Dinsmore & Shohl	d		19,141	24,926	11,639	178,001	233,707	521,080	55%	233,707	(83,707)	150,000		371,080	**371,080**
12	Orrick, Herrington	d		12,605	2,179	460		15,244	0.00		-		-	15,244		**15,244**
13	Hunton & Williams	d		-	-	-	1,730	1,730	0.00				-	1,730		**1,730**
14	**Subtotal Legal**			85,119	54,493	54,079	221,425	**415,116**	**975,700**	**57%**	398,142	(98,142)	**300,000**	15,244	675,700	**692,674**
15																
16	**Total - All Rate Case Expense**			**187,994**	**104,835**	**77,909**	**266,559**	**637,297**	**1,585,977**	**60%**	**620,258**	**(62,211)**	**558,047**	**17,309**	**1,035,680**	**1,054,719**
17				**BREC uses 3-year amort. - divided by 3 years**					**3**		3-year amort.		**3**			3
18				**BREC amortized 3 years and in rate case filing**					**528,659**		OAG allowed - 3 year		**186,016**			351,573
19				**OAG portion of BREC "estimated" that is allowed**					**186,016**					"Not Allowed" includes some		
20				**OAG-5-BCO**					**342,643**					amounts actually incurred		
21														that were not in original estimate		
22	Note 1: BREC original estimated rate case expense at PSC 1-54 (January 29, 2013), and updated costs incurred to date at 1st update February 15, 2013, 2nd update															
23	March 18, 2013, and 3rd updated April 19, 2013.															
24	Note 2: Mr. Wolfram and associates - various (see testimony for description of services).															
25	Note 3 - PSC 1-54 (January 29, 2013) does not explain "Other" estimated legal/consulting witness costs or identfy amounts by specific consultant/attorney.															
26	Services - (a) - Various; (b) - Depreciation; (c) - lobbying; and (d) - legal.															

Kentucky Office of Attorney General
Reduce Expensed Amount of Forecasted Payroll to Historical Levels
Big Rivers Electric Corporation - Case No. 2012-00535
Adjusted Forecasted Test Period

Exhibit BCO-2
Schedule A-7
Adj. OAG-6-BCO

A	B	C	D	E	F	G	H	I	J
		FTP August 31, 2014							
			Note 2		Note 3		Note 1		
No.		Total Payroll with Wilson	Remove BREC Wilson Lay-Up Payroll Adj.	Net Payroll Without Wilson	Payroll Loadings Factor	Loaded Payroll Costs	Revised Exp. Factors	Reduce % Expensed to 3-Period Avg.	Payroll Expense Reduction
1	Exempt labor	19,695,793	0	19,695,793	130%	25,604,531	1.27%	-0.52%	(134,084.39)
2	Non-Exempt Labor	26,073,154	(1,558,742)	24,514,412	130%	31,868,736	2.14%	-1.32%	(421,223.76)
3	Total	45,768,947	(1,558,742)	44,210,205	130%	57,473,267	1.77%		**(555,308)**
4									**Adj. OAG-6-BCO**

5 Note 1 - 3 periods averaged are YTD 2011, Base Period, and YTD 2012.
6 Note 2 - Wilson Lay-Up Payroll Cost Adj. per AG 2-60-(a)
7 Note 3 - Per PSC DR 1-57, Financial Model, O&M tab, rows 137-169 is 30%. In addition, 30% loadings factor appears conservative.
8 **Company Response to OAG DR 1-75(a) and 1-76(a) for 2012**

No.	Test Period	Labor Type	Expensed	Capitalized	Total	Percent Expensed	Percent Capitalized
12	FTP -August 31, 2014	Exempt labor	19,549,570	146,223	19,695,793	99.26%	0.74%
13	FTP -August 31, 2014	Non-exempt labor	25,860,574	212,580	26,073,154	99.18%	0.82%
14		Total	45,410,144	358,803	45,768,947	99.22%	0.78%
15							
16	YTD 2012	Exempt labor	20,170,137	272,067	20,442,204	98.67%	1.33%
17	YTD 2012	Non-exempt labor	28,112,427	729,945	28,842,372	97.47%	2.53%
18		Total	48,282,564	1,002,012	49,284,576	97.97%	2.03%
19							
20	Base Period	Exempt labor	21,419,119	255,530	21,674,649	98.82%	1.18%
21	Base Period	Non-exempt labor	28,437,329	638,926	29,076,255	97.80%	2.20%
22		Total	49,856,448	894,456	50,750,904	98.24%	1.76%
23							
24	YTD 2011	Exempt labor	19,817,638	259,834	20,077,472	98.71%	1.29%
25	YTD 2011	Non-exempt labor	28,277,648	483,535	28,761,183	98.32%	1.68%
26		Total	48,095,286	743,369	48,838,655	98.48%	1.52%
27							
28	3-Period Wtd. Avg. (Note 1)	Exempt labor	61,406,894	787,431	62,194,325	98.73%	1.27%
29	3-Period Wtd. Avg. (Note 1)	Non-exempt labor	84,827,404	1,852,406	86,679,810	97.86%	2.14%
30		Total	146,234,298	2,639,837	148,874,135	98.23%	1.77%

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC	)	
CORPORATION FOR A GENERAL	)	Case No.
ADJUSTMENT IN RATES	)	2012-00535

DIRECT TESTIMONY

OF

LARRY W. HOLLOWAY, P.E.

ON BEHALF OF

KENTUCKY OFFICE OF ATTORNEY GENERAL

PUBLIC REDACTED VERSION

FILED: May 24, 2013

DIRECT TESTIMONY
OF
LARRY W. HOLLOWAY, P.E.

Table of Contents

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2012-00535

DIRECT TESTIMONY OF

LARRY W. HOLLOWAY, P.E.

I. INTRODUCTION

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

A. My name is Larry W. Holloway. My business address is 830 Romine Ridge, Osage City, Kansas. I am an independent consultant testifying on behalf of the Kentucky Office of the Attorney General ("OAG").

Q. Briefly describe your education and work experience.

A. I am a registered professional engineer and have worked over 30 years in all aspects of the electric industry; including generation construction, startup, and operations; regulatory oversight, ratemaking and public policy; and utility resource procurement and management.

My professional experience began outside of the electric industry and includes one year as a field engineer for a natural gas utility and two years as a project engineer for an inorganic chemical plant. Since 1981, the majority of my professional experience has been in the electric industry. I have twelve years of construction, design, startup and operations engineering experience with power plants, primarily nuclear. In 1993, I started work at the Kansas Corporation Commission (KCC) as Chief of Electric Operations, Rates and Services. In 1998, I was promoted to Chief of Energy Operations.

In March of 2009, I accepted the position of Operations Manager with Kansas Power Pool (KPP), a Kansas municipal energy agency. I continue to work at the KPP and do consulting on a part time basis, provided there is no conflict with the responsibilities of my KPP position and I can arrange the necessary time away from my KPP position.

A short summary of my experience and education is attached as Exhibit Holloway-1.

Q. Have you previously filed testimony before this Commission, the Federal Energy Regulatory Commission, or any other state regulatory commissions?

A. I have not previously filed testimony before this Commission. I have filed analysis for settlement purposes at the FERC, and I filed testimony in numerous cases before the Kansas Corporation Commission both as a member of KCC Staff and on behalf of KPP. Testimony I have filed before the KCC includes analysis, review and policy recommendations on utility ratemaking; generation reliability, resource acquisition, planning, dispatch, siting, and fuel and operating costs; utility merger proposal savings and benefits; transmission siting, policy, classification, cost recovery and regionalization; energy cost adjustment mechanisms; and disposition of gain on sale of utility assets. For a full listing of these dockets see Exhibit Holloway-1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I have been asked by the OAG to review the application, testimony, and data responses in this matter, with particular attention to any potential issues in the areas of cost of service, engineering and load forecasts. My comments and recommendations are included in this testimony and cover the topics of maintenance deferral, Wilson layup and depreciation, allocation of costs among rate classes and rate design, transmission cost recovery, and the issue of electric deregulation (specifically retail competition for generation service).

Q. Are you sponsoring any exhibits?

A. Yes, I have prepared the following exhibits:

1. Holloway-1 – Qualifications of Larry W. Holloway, P.E.
2. Holloway-2 – Frequency and Dates of Last Inspections
3. Holloway-3 – RUS Communications on Creep Testing
4. Holloway-4 - RUS Communications on Deferred Maintenance
5. Holloway-5 – Layup Adjustment for Wilson Depreciation Expenses
6. Holloway-6 – Allocation of Transmission Costs to Customer Classes

II. MAINTENANCE DEFERRAL

Q. Have you reviewed Big River's deferral of major maintenance at its generating units?

A. Yes. Big Rivers has deferred major maintenance work at its generation facilities for years. Big Rivers' position is described in the direct testimony of Robert W. Berry, Big Rivers' Vice President, Production ("Berry"):[1]

> **Q. Has Big Rivers deferred any significant planned unit outages since the closing of the Unwind Transaction in July 2009?**
>
> A. Yes. Of the twenty-four maintenance outages that were planned between July 2009 at the closing of the Unwind Transaction and the end of 2014, only two have not been delayed, deferred, reduced in scope and duration, or completely cancelled. …

Q. Has Mr. Berry explained why Big Rivers deferred planned major maintenance activities on its generating facilities?

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[1] See the Direct Testimony of Robert W. Berry, filed January 15, 2013 in this proceeding, p.7, l.14 to p.8, l.1.

A. Berry implies that Big Rivers' precarious financial position prevented it from making the expenditures necessary to properly maintain their assets:[2]

> **Q. Why did Big Rivers defer maintenance outages during this timeframe?**
> A. Big Rivers has had to defer maintenance outages in each of the years 2010, 2011, and 2012 because that was the only option for Big Rivers to meet the minimum margins for interest ratio ("MFIR") required by its loan agreements. …

Q. Why does Berry believe that Big Rivers is in this precarious financial position?

A. According to Berry it is apparently due to the depressed off-system sales market and the Commission's decision not to grant Big Rivers' entire requested revenue increase in the 2011 rate case:

> "As a result of the continued depression in the off-system sales market and the failure of Big Rivers to obtain the full amount of the increase it was seeking in the 2011 Rate Case, Big Rivers was required to defer additional maintenance outages in both 2011 and 2012."[3]

Q. But didn't the Commission grant additional revenue for Big Rivers to perform needed maintenance in the 2011 rate case?

A. Yes. The Commission allowed a substantial adjustment ($4,263,292) in Big Rivers test year revenue requirements to provide the funds necessary to complete deferred maintenance.[4]

Q. What types of maintenance activities has Big Rivers deferred at its generating facilities?

A. Ted J. Kelly ("Kelly") of Burns and McDonnell provides direct testimony regarding Big Rivers' proposed depreciation rates, derived from a depreciation study performed by

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2 Ibid., p.8, l.10 to l.15.
3 Ibid.,p.11, l.7 to l.11.
4 See p. 12 to p. 13 of the November 17, 2011, Order in Case No. 2011-00036 ("the 2011 Rate Case").

Burns and McDonnell. In the depreciation study Burns and McDonnell concludes that: "Since the Unwind Closing in 2009, Big Rivers has not performed major maintenance such as valve inspections and turbine generator inspections on a schedule consistent with prudent utility operations."[5] Additionally, in the review of each of Big Rivers' steam powered generating units - the two Green units, the Reid Plant, the Wilson Plant, the 2 HMP&L units, and the 3 Coleman units - Kelly explains that the depreciation study's engineering assessment of these facilities relies on the Boiler Condition Spreadsheet prepared by Big Rivers for each of these units. Importantly, the following statement occurs in Kelly's testimony regarding each of these units:[6]

> ... Of particular note is the Boiler Condition Spreadsheet that contains a status report on all of the major components in the boiler as well as the High Energy Piping ("HEP") and hangers. A consistent program like this for monitoring status and identifying areas to address in future budgets is very good. The HEP and hanger review addresses the concern over creep damage with an aging plant. This type of review program is critical and is currently being performed on all units.

Q. What does Kelly mean by "creep" damage?

A. Technically creep describes a mechanism where a solid material slowly and permanently deforms while being stressed. In high energy piping systems, such as the steam, boiler or feedwater piping in a steam generating unit, this refers to the deformation of high pressure components over time. While steam plant components are designed and built with materials that have sufficient strength to maintain

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5 See Page ES-3 of Exhibit Kelly-1, 2012 Depreciation Study, from the Direct Testimony of Ted J. Kelly filed January 15, 2013 in this proceeding.

6 See the Direct Testimony of Ted J. Kelly filed January 15, 2013 in this proceeding. For Green units see p.16, l.6 to l.12; for HMP&L units see p.18, l.4 to l.10; for the Reid Plant see p.19, l.19 to p.20, l.3; for the Wilson Plant see p.21, l.8 to l.14; and for the Coleman units see p.23, l.18 to p.24, l.2.

structural integrity when the unit is first constructed, over time operating stresses accumulate and can eventually cause slow and cumulative deformation. While this phenomenon does not occur suddenly, over time creep deformation can lead to a rupture of pressure boundary material.

Q. If creep stress primarily affects HEP, why would prudent utility maintenance practices include inspections of hangers?

A. Kelly is referring to pipe hangers and supports. Pipe hangers and supports for HEP are designed to allow HEP components to expand when heated without creating additional stresses on the piping pressure boundary. Deformed or damaged pipe hangers and supports can cause additional stresses on the HEP as well as identify sections of the HEP where deformation has caused hanger and support damage or misalignment.

Q. What are the possible ramifications of creep damage?

A. As discussed by Kelly, if damage is detected, the components should be evaluated on a regular basis and repaired or replaced.[7] Kelly, however, does not dwell on the possible consequences of not performing these inspections on a regular basis. Failure of the high energy piping components while operating can cause damage to other plant components and injuries to plant personnel. Such an event could result in an unplanned and extended outage.

Q. Is creep damage the only phenomenon addressed by the Boiler Condition Spreadsheet?

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7 Ibid, ES-3.

A. No. While this is an emphasis of Kelly's review, the spreadsheet itself lists many different types of inspections of boiler and HEP components. In response to the OAG's Request for Information dated February 14, 2013 (AG 1) question 140 (AG 1-140) Big Rivers provided the latest Boiler Condition Spreadsheet. A summary of scheduled inspections and when these inspections were last performed is provided as a summary in Exhibit Holloway-2.

Q. Are there any observations that raise concerns regarding the inspections and the schedule of inspections shown on the Boiler Condition Spreadsheet?

A. Yes. As shown on Exhibit Holloway -2 it appears that several of the units are behind on Big Rivers' inspection schedule for pressure relief devices, HEP and HEP supports.[8] It is important to note that the maintenance activities detailed in this Boiler Condition Spreadsheet are not my recommendations, the spreadsheet is a tool developed by Big Rivers to indicate when prudent utility maintenance should occur.

One of the critical components listed is the overpressure protection devices on the high energy piping system and components. These devices are typically a form of relief or safety valve and are listed here as "safeties". Just as the relief valve on your hot water tank protects your home and its occupants from damage resulting from an over-pressure explosion of your hot water heater, these devices protect power plant components and personnel from over-pressurization of high energy piping and components. I am not familiar with the specific boiler code requirements for each of

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[8] On Exhibit Holloway-2, Examples of Pressure Relief Devices are highlighted in yellow Examples of HEP and HEP Supports are highlighted in green.

these components at each of Big Rivers' steam units. However, it is a reasonable assumption that the specific boiler code requirements, whatever their year, version, chapter and verse, require Big Rivers to properly maintain, inspect and test these overpressure protection devices at regular intervals. Nonetheless, as indicated by the following table, it would appear that Big Rivers has seriously neglected its own maintenance plan for these critical components on a number of its units.

Table 1
Inspections of Over Pressure Protection Devices (Safeties) Indicated on Latest Boiler Condition Spreadsheet Provided in Response to AG 1-140

Unit	Frequency	Last Performed	Years Overdue
Coleman 1	3 years	May-08	2
Coleman 2	3 years	May-07	3
Coleman 3	3 years	Jun-09	1
Green 1	4 years	Nov-11	Current
Green 2 (main steam and drum)	4 years	May-09	Current
Green 2 (reheat)	4 years	May-05	4
HMPL 1	4 years	Mar-11	Current
HMPL 2	4 years	Feb-12	Current
Reid	4 years	Jun-08	1
Wilson	2 years	Nov-09	1

In addition to overpressure protection devices, Big Rivers' Boiler Condition Spreadsheet also list inspections and maintenance requirements for HEP and HEP supports. As shown in the following table, Big Rivers has also not met its own maintenance schedule for these important components at several of its steam plants.

Table 2
Inspections of High Energy Piping and Piping Supports

Unit	Frequency	Last Performed	Years Overdue
Coleman 1	3 years	May-08	2
Coleman 2	3 years	May-07	3
Coleman 3	3 years	Jun-09	1
Green 1 (hangers)	Annually	Nov-11	1
Green 1 HEP (most)	2 years	Nov-11	Current
Green 2 (hangers)	Annually	Apr-09	3
Green 2 HEP (most)	2 years	May-09	2
HMPL 1	4 years	Mar-11	Current
HMPL 2	4 years	Feb-12	Current
Reid	4 years	Jun-08	1
Wilson (hangers)	2 years	Nov-09	1
Wilson (Piping)	6 years	Nov-09	Current

Q. Has Big Rivers performed inspections for creep damage at its steam units?

A. Yes, however, it has not done so on its own maintenance schedule. In a response to questions by the Rural Utility Service (RUS), Big Rivers provided its creep testing completion results.[9] As a result of the most recent inspections, problems were identified at Coleman 1, Coleman 3 and Reid. Despite this, Big Rivers has not met the inspection intervals on its Boiler Condition Spreadsheet for several of its units.

Q. Has RUS expressed concern regarding Big Rivers' deferral of maintenance activities on its units?

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9 See Exhibit Holloway-3.

A. Yes. When Big Rivers submitted its depreciation study to RUS, RUS responded with concern that this maintenance deferral was "not acceptable to RUS" and that "Big Rivers needs to resume their scheduled major inspections and maintenance per prudent utility operations promptly."[10]

Q. How did Big Rivers respond to the RUS?

A. RUS based its concerns on the depreciation study performed by Burns and McDonnell. As shown on Exhibit Holloway-4 on February 6, 2013 Big Rivers responded to RUS by providing a few pages of Kelly's direct testimony. In particular Big Rivers defended its position based on a statement added to Kelly's testimony *[emphasis added]*:

> "... RUS indicated that Big Rivers needs to resume its scheduled major inspections and maintenance practices. RUS may have misunderstood what we were indicating in the report. As a result of prevailing resource constraints, Big Rivers selectively deferred some major maintenance while RUS indicated that Big Rivers needs to resume its scheduled major inspections and maintenance practices. RUS may have misunderstood what we were indicating in the report. As a result of prevailing resource constraints, Big Rivers selectively deferred some major maintenance while continuing routine maintenance. *Inspections performed by Burns & McDonnell and a review of operating results over the last several years indicated no adverse conditions as a result of this short term deferral.* Burns & McDonnell did review Big Rivers' plans, developed in May 2012, to reschedule the maintenance activities that are described by Bob Berry in his testimony. In light of the favorable operating results and assuming timely rescheduling of the deferred maintenance, in our opinion Big Rivers showed good judgment in the use of available resources and its facilities are being reasonably and prudently operated."[11]

Q. What type of inspections did Burns and McDonnell perform?

A. As described by the depreciation study, none. In 2010 Burns and McDonnell completed "physical site observations" and applied "engineering judgment" to

[10] See the December 27, 2012 letter from RUS to Bailey, included with related correspondence in Exhibit Holloway-4.

[11] See the Direct Testimony of Ted J. Kelly filed January 15, 2013 in this proceeding, p.13, l.19 to p. 14, l.9.

approximate the remaining lives of Big Rivers' generating facilities.[12] Physical site observations do not rise to the level of the types of inspections expected and documented on the Boiler Condition spreadsheet. In addition, as described by Kelly, Burns and McDonnell did not even perform these site observations in preparing its depreciation study for this case:

> "Burns and McDonnell's approach to meeting the requirements for the Study was based substantially on performance of the previously completed physical site observations of the generating and transmission facilities by experienced power plant design engineers and transmission system engineers, respectively. These engineers then applied their experience and engineering judgment in approximating the remaining lives of each of Big Rivers' generating facilities. ..."[13]

Burns and McDonnell is a reputable firm with extensive power plant engineering experience. Nonetheless, this hardly supports Kelly's defense of Big Rivers' decision to defer maintenance. There were no Burns and McDonnell inspections over the last several years, instead there were "physical site observations" and these were performed in 2010. Kelly's attempt to justify Big Rivers' maintenance deferral exaggerates the scope and extent of Burns and McDonnell's single visit in 2010.

Q. But doesn't Kelly also base his conclusions on Big Rivers' "favorable operating results"?

A. Yes. However, it is important to understand that Burns and McDonnell's engineering assessment of the remaining life of Big Rivers' generating plants is primarily based upon their susceptibility to creep stress.[14] But creep stress failure is a long-term

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12 Ibid, ES-1.
13 Ibid, ES-1.
14 Ibid, ES-3 to ES-4.

phenomenon and would likely have no effect on short-term reliability. Deferring maintenance activities that are needed to address this long-term failure mechanism could cause problems many years from now. The mere observation that extended and unplanned maintenance activities have not occurred recently does not mean that delaying needed maintenance has caused no harm. In fact it is possible that future equipment failures could be prevented if this maintenance had been performed as scheduled.

Q. Do you believe that favorable operating results justify Big Rivers' maintenance deferral decisions?

A. No. As discussed above, the types of maintenance activities deferred - creep stress testing, inspection and testing of HEP and HEP supports, inspection and testing of overpressure protection devices, major valve inspections and turbine generator inspections - are not activities that, if skipped, are likely to affect short-term reliability measurements. In fact, these are the type of maintenance activities that help prevent major catastrophic equipment failures or unexpected extended outages in the future and will ensure that these assets remain useful for a long and productive service life.

As an example, consider many modern cars with overhead camshafts and close valve clearances. On many of these vehicles the manufacturer recommends that the timing belt should be replaced every 100,000 miles or so. However if you have ever looked at a timing belt that has been removed and replaced after 100,000 miles you will usually notice that it looks as if you could continue to operate the vehicle for another 100,000 miles with little risk of the belt breaking. Nonetheless, the manufacturer recommends this replacement because the consequences of the timing belt breaking is severe and would likely result in destroying the engine. Because of this possibility, most prudent owners would prefer to spend several hundred dollars replacing the timing belt, rather than take the chance that they would need to spend thousands of dollars to repair or replace the engine.

I believe that by deferring these important maintenance activities Big Rivers may be risking its most valuable assets. Just because the performance of the units has not been affected to date does not indicate that the decision to defer this maintenance has been prudent. Furthermore, it would seem that the Commission granted Big Rivers the needed revenue specifically to perform this maintenance in the 2011 Rate Case and Big Rivers chose not to do so. Granted there would appear to be reasons Big Rivers chose not to do this. Referring to the prior analogy, I am sure we could all come up with reasons not to spend the money to replace the timing belt. Nonetheless I believe this is indicative of questionable management priorities and judgment.

Q. **Do you have other concerns regarding Big Rivers' deferral of important maintenance activities?**

A. Yes and these concerns are primarily one of incentive. In the 2011 Rate Case, the Commission granted Big Rivers the revenue necessary to perform the maintenance it chose to defer. In this proceeding Big Rivers has included the revenue necessary to "catch up" on its deferred maintenance. Furthermore, Kelly has indicated that if this maintenance is not performed, depreciation rates could be increased due to shortened life expectancy of Big Rivers' generating plants. Where is the incentive for Big Rivers to perform this maintenance? In the next proceeding Big Rivers can merely ask for even more revenue to perform maintenance it has deferred. Furthermore, the next depreciation study can ask for higher depreciation rates because of the lack of adequate maintenance. While I do not doubt that Big Rivers would like to perform needed maintenance on its generating facilities, it would seem that their current regulatory plan creates a perverse incentive to avoid proper and prudent maintenance of their generation facilities.

Q. Do you have any recommendations for the Commission regarding the issue of deferred maintenance?

A. Yes. Big Rivers has provided a forecast of anticipated maintenance activities needed to "catch up" on its deferred maintenance. The Commission should require Big Rivers to file at regular intervals, but at no less than annually an updated report on its progress to complete these maintenance activities. To the extent Big Rivers has not completed the maintenance activities by the targeted dates, Big Rivers should be required to immediately refund the revenues granted by the Commission in this proceeding to complete these activities to its customers.

III. WILSON DEPRECIATION

Q. Have you reviewed the depreciation study provided by Big Rivers?

A. I have reviewed the depreciation testimony and recommendations provided as a result of the Burns and McDonnell depreciation study. I have not performed an alternative depreciation study. Nonetheless, I do have a few observations regarding the depreciation study and the conclusions reached regarding the Wilson plant.

Q. What is the primary basis for establishing the estimated useful lives for Big Rivers' generating plant assets in the Burns and McDonnell depreciation study?

A. As stated in the study, Burns and McDonnell based its analysis, at least in part, on the expected accumulated creep stresses on the unit due to hours of service.[15] In fact, the basis for the engineering assessment performed on the units uses an assumed estimated remaining plant life based on total estimated hours of service.[16]

Q. What did Kelly conclude regarding the Wilson Plant?

A. Kelly concluded that the average remaining service life for Wilson account 311, structures, could be assumed to be 28 years and the average remaining service life for plant account 312, Boiler Plant, and account 314, Turbine, was 26 years.[17] Table ES-1 of the study goes further and provides remaining service lives for all of generating plant accounts

Q. How does this affect the depreciation rate for the Wilson unit?

A. Big Rivers' Forecasted Test Period ("FTP") presented in its application assumes that the Wilson unit will be in layup for the next 4 years. In essence this means that Wilson will incur no hours of service over the next 4 years. Therefore it seems reasonable to conclude that the following changes should be made to the Remaining Service Lives for the Wilson Plant accounts as I provide on Table 3.

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15 Ibid, ES-3.

16 Ibid, II-2 through II-7.

17 Ibid, ES-III-8

Table 3
Wilson Remaining Service Life with 4 Year Layup

Plant Account	Description	Remaining Service Life per Table ES-1	Remaining Service Life with 4 Years of Layup
311	Structures	28.2	32.2
312	Boiler Plant	26.1	30.1
312 A-K	Boiler Plant - Environment Compliance	26.3	30.3
312 L-P	Short-Life Production Plant - Environmental	4.4	8.8
314	Turbine	26.5	30.5
315	Electric Equipment	18.3	22.3
316	Miscellaneous Equipment	24.3	28.3

Q. Assuming that all Wilson remaining service lives are extended by 4 years while the plant is in layup, have you provided a calculation for the effect on depreciation expenses?

A. Yes. By using the July 2012 plant account balances provided in response to KIUC 2-20(a) and modifying table ES-1 to show the extended remaining lives for these Wilson Accounts, I calculated the change in depreciation expenses from the current depreciation expenses being charged in the forecasted test period. This calculation and the resulting adjustment of ($2,907,791) are shown on Exhibit Holloway-4.

Q. Are you recommending that this adjustment should be made to recognize the Wilson layup during the forecasted test period?

A. I believe the entire issue of rate treatment of Wilson costs should be carefully considered by the Commission. To the extent that the Commission believes that Wilson costs should be recovered even though the facility will be neither used nor useful during the forecasted test period, I believe the Commission should at the very least adjust the Wilson depreciation expenses to recognize that the remaining service life of the plant accounts will be extended by the forecasted layup period. Mr. Brevitz further addresses in his testimony the extent to which Wilson is "used and useful" from a ratemaking perspective and whether therefore Wilson costs should be included in revenue requirements in this case.

IV. COST OF SERVICE MODEL

Q. Have you reviewed the cost of service study presented by Big Rivers' witness John Wolfram ("Wolfram")?

A. Yes. While I have not provided an alternative cost of service study, I do have several comments and observations regarding Wolfram's study. First, I have concerns regarding the presentation of revenue increases as I believe it does not accurately reflect the effect of the proposed changes the requested rates will have on each customer class. Second, I am concerned that the forecasted billing determinants for the rural and industrial customers contain a bias that could result in a rate design that would recover more than the requested revenue increase. Third, as I will discuss later, Big Rivers has based the costs in its application on the assumption that Century will continue to take transmission service from Big Rivers, therefore it is reasonable to assume Big Rivers will continue to recover revenue for Century's use of its transmission system.

Q. Please describe your concerns regarding the presentation of the revenue increases.

A. It is always difficult to simply present how the change in rates collected from customers will increase their bills in terms of percentage or similar general observations. However, it is important to understand that Big Rivers' rate increase is a major change in rate design as well as a major increase in overall revenue collected from each rate class. While I do not fault Big Rivers for its overall presentation of these increases, it is important to note that there will be a much greater impact on certain customers than others. In the rural class, for example, while the overall increase is estimated to be an increase of revenue of $39,375,628, or an increase of 28.3%[18], this increase in revenue is collected through a major change in rate design. Of the $39,375,628 increase, Big Rivers is proposing to collect $38,059,745, or 98.3%, by increasing the Rural Demand Charge from $9.697/kW-Mo to $16.848/kW-Mo, or by increasing this charge by 74%.[19] Assuming Big Rivers' members pass these costs along to the Rural residential and small commercial customers in the same fashion, this will result in a much larger rate impact for those customers with lower than average load factors. For example schools, small retail businesses, churches and residentials often have lower-than-average load factors because no one is present for large periods of time. These types of residences,

[18] See revised Exhbit Wolfram-5.2 as provided in response to PSC 2-36.

[19] Ibid.

institutions and businesses will be most impacted by this dramatic shift to demand-based cost recovery for this customer class.

Q. Would you agree that increasing the Rural Demand Charge by 74% is a "gradual" increase?

A. No. This is a dramatic increase in this charge and a major change in the way revenues from the Rural customer class are collected. It is my understanding that the Commission has a policy of gradualism for adjustments in cost allocation among rate classes.[20] Nonetheless I am concerned that for many retail customers the net effect of this increase will be anything but gradual.

For example Big Rivers' members Kenergy and Jackson Purchase have their retail tariffs available online. After reviewing these tariffs I observed that even small commercial customers on their systems have demand charges. Should these utilities pass through the same magnitude of demand charge increase Big Rivers is advocating for the Rural customer class, the net effect on small businesses, schools and churches among others would certainly not seem gradual. Additionally this will likely eventually filter down to residential customers on fixed incomes and others that make a conscious effort to conserve usage.

Q. How would the proposed increase in Big Rivers Rural demand rate affect the members' retail residential customers if these customers do not have a demand rate?

A. Moving to a rate design that involves higher revenue recovery from demand charges has a net result of increasing costs for customers with lower load factors. When Big

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[20] See response to AG 1-30

Rivers' members design their retail rates to allocate theses costs to their retail customers they will be faced with the difficult decision to either dramatically increase charges for residential customers, or to implement further rate subsidies from commercial customers. Because residential customers typically do not have demand meters, the only way to recover these costs without subsidy from other rate classes will be to dramatically increase customer charges, energy rates, or both. Under either of the above mentioned approached the residentials and commercials would be straddled with rate increases that would simply not be economically feasible.

V. LOAD FORECAST

Q. Have you reviewed the load forecast used in Big Rivers' fully forecasted test period?

A. I have not performed an alternative load forecast, but I have reviewed the forecast used by Big Rivers to arrive at its allocation of costs and rate design. I do have concerns with some of the assumptions used by Big Rivers and the resulting load forecast. From an overall perspective, Big Rivers' load forecast assumes very little growth in the industrial load and an increasing load in the rural class. This appears questionable when one reviews the actual historic data and compares it to the forecasted test period and beyond.

Q. Please elaborate on your observation of the actual Industrial and Rural load as compared to Big Rivers' load forecast.

A. I compared the actual loads recorded for the industrial and rural customers for the periods of 2010, 2011 and 2012, as provided in the confidential response to AG 1-128 with the forecasted values used in the fully forecasted test period and beyond, as provided in the public response to AG 1-127. As a result, the comparison seems to indicate a slight emphasis to assigning costs to the rural customers. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** These observations are shown on the following tables. Table 4 illustrates the actual and forecasted rural demand from 2010 through 2016, as well as the fully forecasted test period. Table 5 illustrates the actual and forecasted industrial demand over the same periods. Table 6 illustrates the annual change in Demand for both the industrial and retail customer classes over the same period.[21]

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21 Annual monthly demands represent the monthly demands for every month of the year added together. For example if a load had a demand of 1 kW for each of 6 months in a year and a demand of 2 kW for the other 6 months of a year, the annual monthly demand would be (1 kW X 6 months) + (2 kW X 6 months) = 18 kW-Mo for the year.

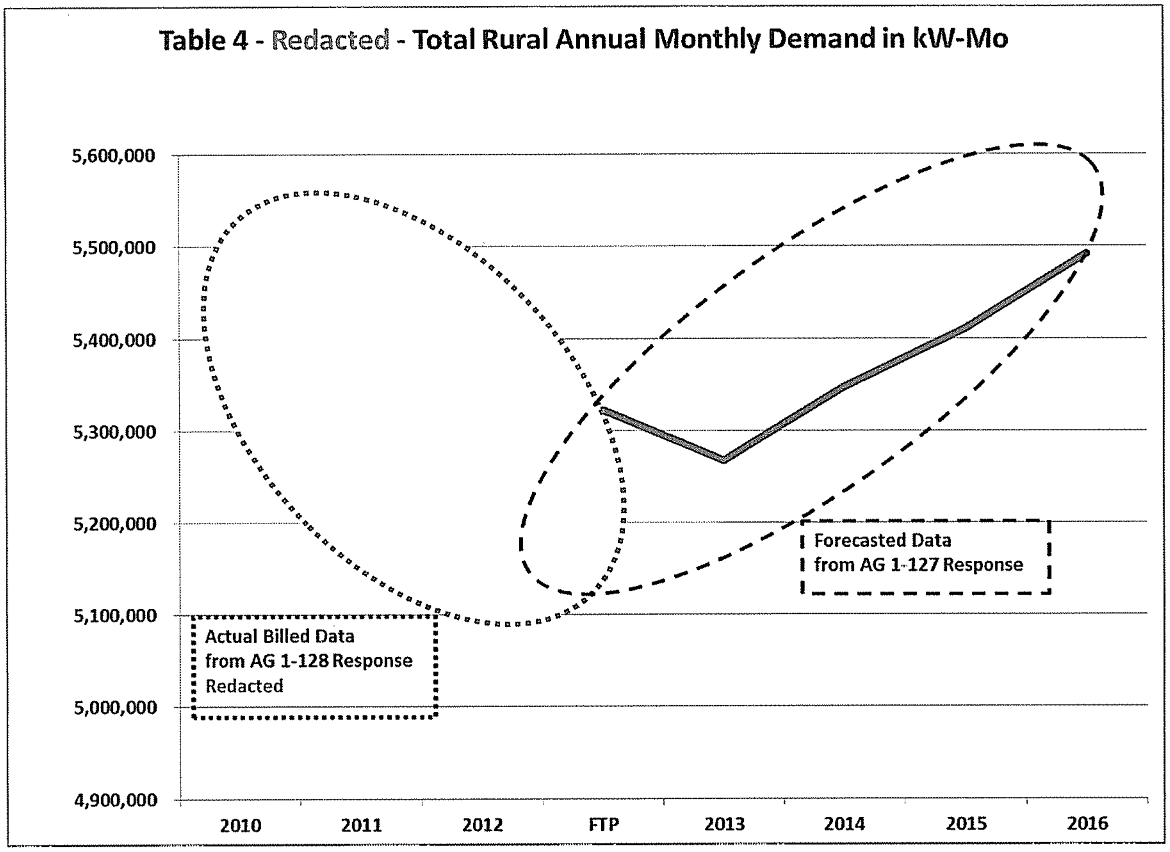


Table 4 - Redacted - Total Rural Annual Monthly Demand in kW-Mo
5,600,000
5,500,000
5,400,000
5,300,000
5,200,000
5,100,000
5,000,000
4,900,000
Actual Billed Data
from AG 1-128 Response
Redacted
Forecasted Data
from AG 1-127 Response
2010
2011
2012
FTP
2013
2014
2015
2016

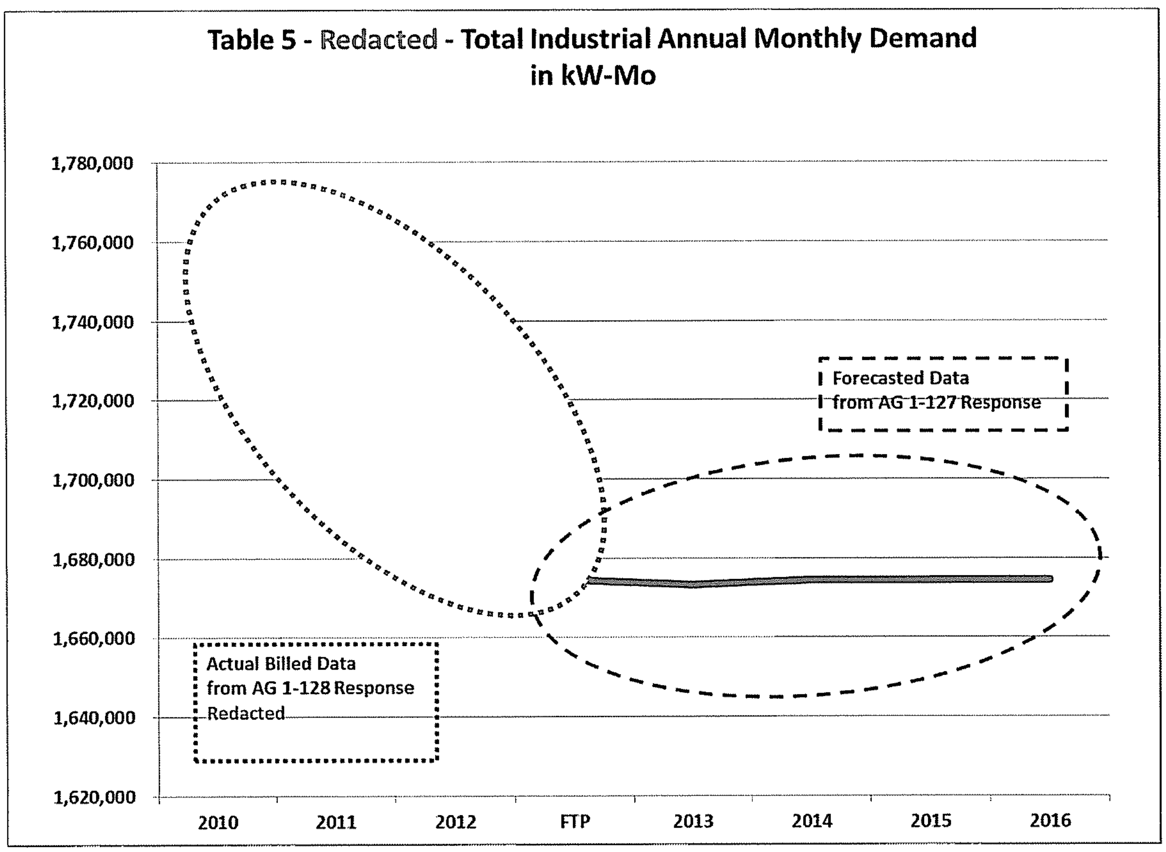
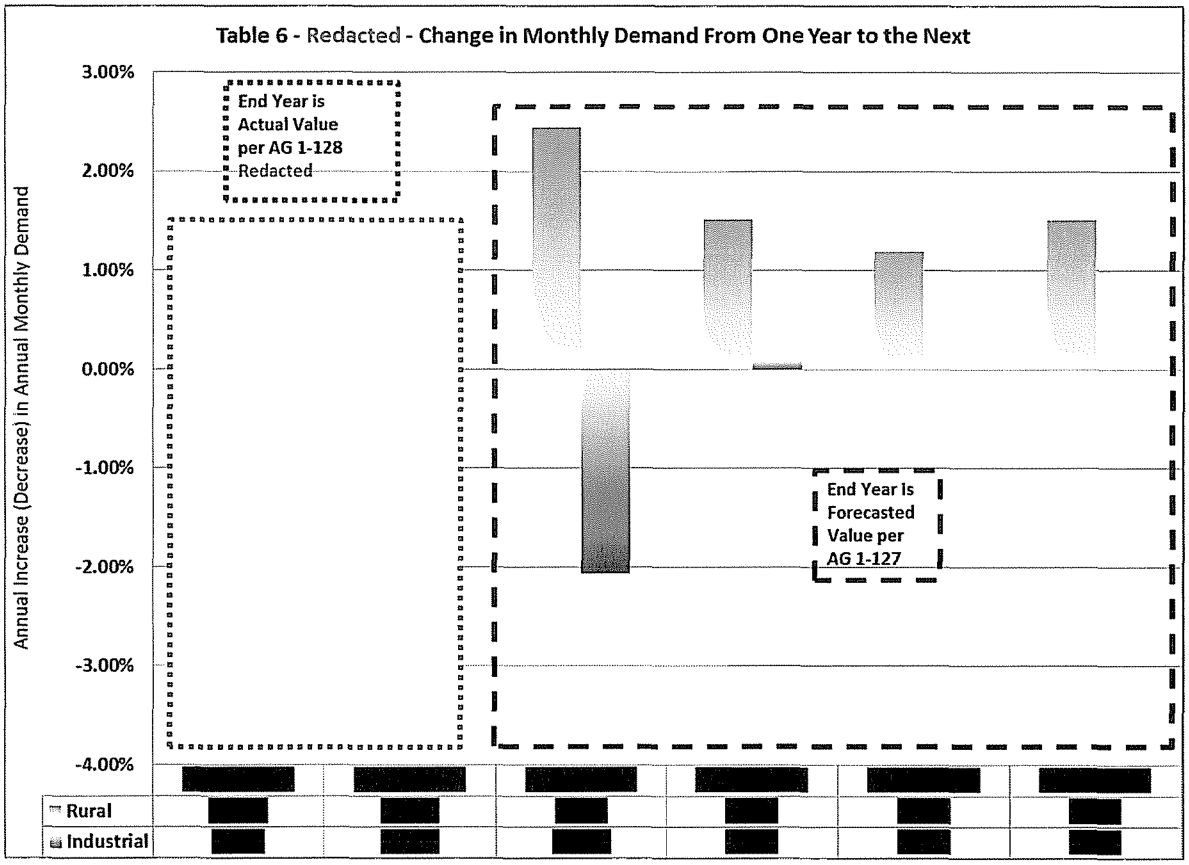


Table 5 - Redacted - Total Industrial Annual Monthly Demand
in kW-Mo
1,780,000
1,760,000
1,740,000
1,720,000
1,700,000
1,680,000
1,660,000
1,640,000
1,620,000
Forecasted Data
from AG 1-127 Response
Actual Billed Data
from AG 1-128 Response
Redacted
2010
2011
2012
FTP
2013
2014
2015
2016



Q. Do the same observations hold for the energy use in the Rural and Industrial forecasts?

A. Yes. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** Nonetheless, Big Rivers forecasts decreased and flat energy usage for the industrial customer class over the forecasted period. These observations are shown on the following tables. Table 7 illustrates the actual and forecasted rural energy use from 2010 through 2016, as well as the fully forecasted test period. Table 8 illustrates the actual and forecasted industrial energy use over the same periods. Table 9 illustrates the annual change in energy use for both the industrial and retail customer classes over the same period.

Table 7 - Redacted - Total Rural Energy Annual Use in kWh

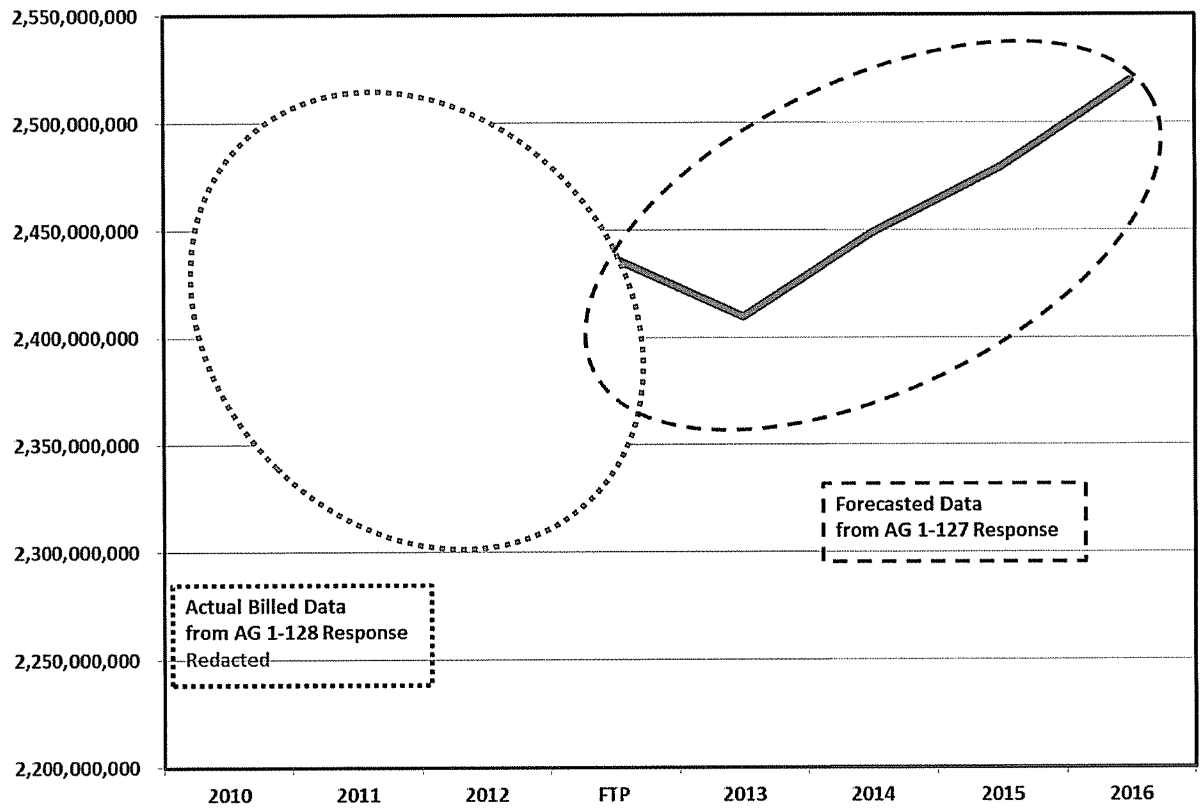


Table 8 - Redacted - Total Industrial Annual Energy in kWh

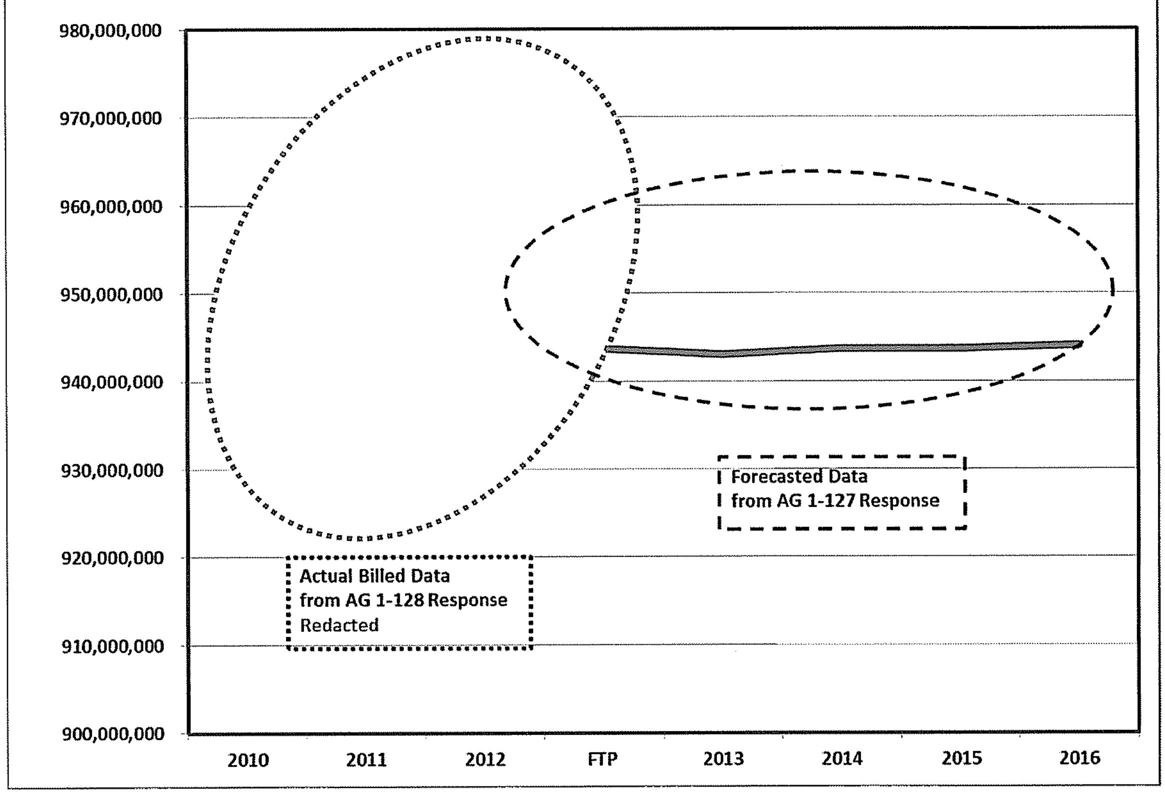
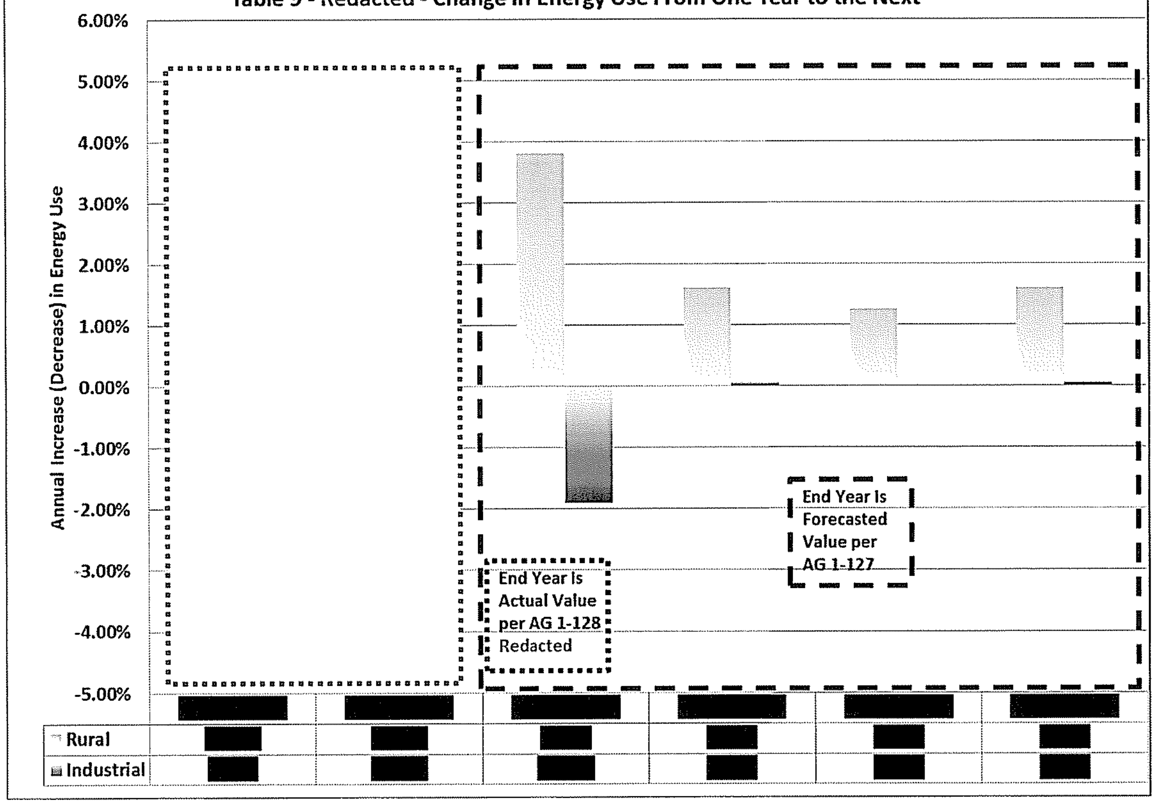


Table 9 - Redacted - Change in Energy Use From One Year to the Next



Q. What does the load forecast for the fully forecasted test period indicate?

A. The forecast implies that the only growth actually expected is the growth in Rural Demand and Rural energy use. However, in various responses Big Rivers has indicated that it hopes to be able to make up for the loss of Century load with the addition of industrial customers. It is ironic that Big Rivers is anticipating increasing its industrial sales as a way out of its financial problems but its actual forecasts show load growth only for Rural customers, despite recent trends.

VI. REMOVAL OF CENTURY TRANSMISSION REVENUES

Q. Have you reviewed the costs of transmission included in the cost of service study?

A. Yes. Wolfram includes the bundled cost of transmission service in his allocation of costs and subsequent determination of rates using the fully forecasted test period. Transmission costs included in the revenue requirements per the cost allocation worksheets are $31,508,389 for the fully forecasted test period.[22]

Q. How are these costs allocated?

A. These costs are allocated to three customer classes, Rural customers, large industrial customers and the Alcan smelter using the 12 CP methodology.

Q. Are there any costs allocated to the Century Smelter?

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22 See revised Exhibit Wolfram-4.2 as provided in response to PSC 2-36.

A. No. The premise of the fully forecasted test period is to assume the Century load is no longer served by Big Rivers. In other words Big Rivers simply assumed that no costs projected from the fully forecasted test period would be recovered from Century.

Q. Is this approach consistent with the various assumptions that Big Rivers has made in developing its revenue requirements?

A. No. While this will be discussed in further detail later in my testimony, it is sufficient at this point to merely state that the overall assumption of many of the costs estimated in the fully forecasted test period is that the Century load will continue to receive transmission service from Big Rivers.

Q. If the Century load remains on Big Rivers' transmission system, is the cost allocation of transmission revenue requirements provided by Wolfram valid?

A. The overall estimate of transmission revenue requirements based on the fully forecasted test period is unaffected. However, the allocation among customer classes would change.

Q. How would the allocation of transmission costs among customers change if the Century load continues to take transmission service from Big Rivers during the fully forecasted test period?

A. Big Rivers' cost of service study allocates the $31,508,389 of transmission revenue requirements as follows: $15,037,920 to the Rural rate class, $3,994,404 to the Large Industrial rate class, and $12,476,695 to the Smelter class (Alcan only). As shown in Exhibit Holloway-6, if the Century load is considered to remain on Big Rivers' transmission system, the $31,508,389 of transmission revenue requirements would be allocated as follows: $9,901,763 to the Rural rate class, $2,630,237 to the Large Industrial rate class, $8,215,660 to Alcan and $10,760,729 to Century. The result is that the fully forecasted test period revenue deficiency that Big Rivers is seeking to collect from the full requirements Rural rate class, the large industrial rate class and Alcan is overstated by $10,760,729.

VII. DECISION TO IDLE WILSON

Q. Why did Big Rivers decide to idle a generating plant?

A. As described by Berry, when Big Rivers received Century's Notice of Termination on August 20, 2012, Big Rivers began implementing its Load Concentration Mitigation Plan.[23] One of the steps in the plan is for Big Rivers to idle or reduce generation when the market price does not support the cost of generating.[24]

Q. Why did Big Rivers decide to idle the Wilson plant?

A. Berry provides an explanation of Big Rivers' decision in his testimony.[25] As a member of the Midwest Independent System Operator (MISO) Big Rivers must get approval to layup any generating station to ensure that there is not an adverse impact on transmission system reliability. Big Rivers assumed that because of the proximity of the Coleman station to the Century smelter that if Century continued to operate, it would not be allowed to idle the Coleman generating plants. Because Wilson is not in the same proximity as the Century facility, Big Rivers believes that idling the Wilson facility

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23 See the Direct Testimony of Robert W. Berry filed January 15, 2013 in this proceeding, p.19, l.8 to l.13.
24 Ibid, p.66, l.5 to l.8.
25 Ibid, p.23, l.6 to l.18

will not have the same impact on transmission system reliability should the Century facility continue to operate (and thus require use of the transmission system).

Q. Isn't the Wilson plant the newest generation source for Big Rivers and less expensive to operate than the Coleman units?

A. Yes. Big Rivers has provided a comparison of system fuel costs for its coal units over the 2014 through 2016 forecasted period in response to KIUC 2-3. In this response Big Rivers evaluated **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** Furthermore in response to KIUC 2-56 Big Rivers states that the fixed costs for operating Coleman and idling Wilson are **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** the 2014 to 2016 time period than the costs for idling Wilson and operating Coleman.

Q. Has Big Rivers finalized the decision to idle Wilson?

A. No. As stated Big Rivers must get approval from MISO before idling any generation facility. Currently Big Rivers has indicated that it has not received the necessary "Y-2 report" from MISO. Additionally Big Rivers is also not certain whether Century will be operating.[26]

Q. To clarify, Big Rivers does not know for sure if it will idle either Wilson or Coleman Stations, but has made a far more expensive assumption that it will idle Wilson in presenting its requested revenue increase for the fully forecasted test period, is that correct?

A. Yes. Big Rivers has assumed that Wilson will be idled because MISO would not allow Coleman to be idled if Century load remains on Big Rivers' transmission system.

Q. But doesn't Big Rivers assume that if the Century load goes away it would be allowed to idle Coleman instead?

A. Yes. Big Rivers assumes that if the Century load is no longer on its transmission system, MISO would probably not have reliability concerns that would require Big Rivers to operate Coleman instead of Wilson.

Q. So Big Rivers has included the extra costs of operating Coleman instead of Wilson in its fully forecasted test period AND assumed that it will receive no revenue from Century for use of its transmission system?

A. Yes. Big Rivers has played both sides of the court on this issue. The Commission must decide which it should allow, the extra costs for Coleman, or the assumption that Wilson will be idled and that Century will continue to purchase transmission service

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26 See response to KIUC 2-3.

from Big Rivers. Big Rivers cannot justify both assumptions in its application. Nonetheless, it is important to note that Big Rivers has decided to go with the assumption that Wilson will be idled, and this assumption is continued throughout its financial models and the case as presented.

VIII. WILSON LAYUP PLAN

Q. Have you reviewed the Wilson layup plan that Big Rivers intends to implement?

A. Yes. Big Rivers provided its layup plan in response to PSC 2-21. The layup plan is extensive and includes multiple spreadsheets with detailed and regularly scheduled activities, including procedures for various plant systems and equipment. Additionally many of the activities require equipment to be secured, disassembled, drained, disconnected, protected with corrosion inhibitors, lubricated and/or periodically rotated or operated. In response to PSC 2-21 (e) Big Rivers describes the layup state for Wilson as: "Mothballed – State where unit is unavailable for service, but can be brought back into service with the appropriate amount of notification, typically weeks or months."

Q. What do you conclude regarding the Wilson layup plan?

A. It would appear that Big Rivers is taking precautions and going to considerable effort to ensure that Wilson will not noticeably degrade or appreciably age while in this mothballed status.

Q. Does Big Rivers believe that these precautions to preserve the plant should increase its useful life?

A. No. In response to AG 2-25 Big Rivers indicated it did not agree that plant depreciation should be suspended while the plant is idled, because "Big Rivers expects that Wilson Station will remain in service and available to operate as needed to cover outages at other stations and to maintain its environmental permits."[27] Nonetheless, Big Rivers did concede that "The remaining useful life of fossil fired steam generating assets is typically estimated based on expected hours of operation and anticipated number of thermal cycles. ..."[28] But Big Rivers went on to state its belief that future depreciation studies would determine if the useful life of the facility was extended by the long period of layup anticipated. Regardless, as previously discussed, the current depreciation study relies heavily on the actual accumulated operating hours. I would recommend that if the Commission allows Wilson costs to remain in rates during the idled period, the depreciation expenses should be adjusted accordingly.

Q. How long does Big Rivers intend to idle Wilson?

A. As stated in Big Rivers' response to PSC 2-21 (c), the current financial model assumes the unit will be idled until 2019. Big Rivers also states that the "Wilson station will be available to operate as needed to cover outages at other stations and to maintain its current environmental permits."

Q. If Wilson is "mothballed" when it is idled, as planned, what level of activity is necessary to restart the unit?

A. While Big Rivers has stated that the Wilson Station will be available to operate as needed, in its response to AG 1-111 Big Rivers indicated that it expected it would take

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27 See response to AG 2-25 (c).

28 See response to AG 2-25.

approximately 43 days to restore the unit from an idled status. Additionally there would be a need to restore consumables such as fuel oil, water treatment chemicals and demineralizer resins, in addition to coal. Furthermore, the decision to idle Wilson also defers needed maintenance that should be performed before the unit can be restarted. As stated in Big Rivers' response to AG 1-111 (g):

> " ... Therefore, the bare minimum cost to restart Wilson Station is $1,470,492 with the aforementioned labor cost still to be added. It should be noted that Wilson Station has deferred maintenance from 2013 that amounts to $11,891,000 ($7,139,000 in Capital and $4,752,000 in fixed O&M). Big Rivers plans to complete this outage work before restarting Wilson Station."

Q. What do you conclude about the availability of Wilson to cover outages at other stations and to maintain its environmental permits?

A. While I am not familiar with the nuances of the Wilson environmental permits and how these would affect Wilson operations, it does not appear that Wilson would be readily available except for unplanned and unanticipated lengthy outages. I mention this for two reasons. First, it is difficult to argue that in this extended layup condition that Wilson is used and useful for utility operations. Second, I would hope that Big Rivers does not take the "availability" of restoring Wilson to service from its layup condition as a justification for deferring any needed maintenance at its other units.

IX. RETAIL COMPETITION (DEREGULATION)

Q. Are you familiar with the discussion going on in the State of Kentucky regarding deregulation for electric supply ("retail competition")?

A. It is my understanding that this issue has been debated during the recent legislative session and may be gaining support among industrial customers.

Q. Is this the first time this issue has been reviewed in the state of Kentucky?

A. No. House Joint Resolution (HJR) 95 passed during the 1998 session of the General Assembly established a Special Task Force on Electricity Restructuring. I have reviewed the task force's final report[29] and while this report was written over a dozen years ago most of the conclusions and findings appear current to the topics being discussed in the context of this proceedings

Q. What were the task forces' recommendations?

A. The task force recommended that the General Assembly take no action to restructure the Kentucky electric utility industry in 2000, continue to study the issue of retail competition, and monitor actions taken in other states that have opened retail markets to competition. Given some of the findings in the study the recommendations were not surprising.

Q. How did the study's findings support the task force's recommendations?

A. Many of the findings at that time seem very current today. For example, the study concluded that retail competition would mean that electricity prices would less than regulated prices with low fuel costs and higher with high fuel costs. As predicted by the study, today low natural gas prices are causing an increased interest in retail competition in Kentucky. Additionally the study concluded that deregulated

[29] Research Report No. 299, Legislative Research Commission, published September 2000, Final Report Special Task Force on Electricity Restructuring; *Restructuring Kentucky's Electric Utility Industry: An Assessment of and Recommendation for Future Action in Kentucky.*

generation costs would be expected to vary across the state depending on the existing utility's rates. As expected electricity costs would increase for customers being served by low cost utilities and decrease for customers served by high cost utilities. Furthermore the study found that Big Rivers was one of only three utilities in the state that would have stranded costs from implementation of retail competition:

> Positive stranded costs are comprised of purchase power contracts and are concentrated in three utilities: Cinergy's Union Light Heat & Power, Big Rivers, and distribution utilities served by TVA. Their positive stranded costs collectively could range from $295 million to over $1 billion.1 The remaining utilities are in a "negative stranded cost" position, which means that the market value of their generating assets and purchase power contracts is higher than the book value for these assets in a regulated market. Potential negative stranded costs in Kentucky range from nearly $700 million to $3.7 billion.[30]

Q. Do you have any related experience with this issue?

A. Yes. In 1996 the Kansas Legislature passed a bill establishing a retail wheeling task force. As part of this legislation the Kansas Corporation Commission (KCC, the public service commission in Kansas) was directed to not authorize retail competition before July 1, 1999. The task force was directed to provide a final report to the Kansas Legislature before the 1998 legislative session. As detailed in the legislation, the task force was made up of 23 members, including a member of the KCC Staff. I was appointed by the Commission to serve as the KCC Staff member. At the same time as this was going on, the KCC opened a "generic" docket to consider the issue.

Q. Why did the KCC open a docket if the issue was already being considered by the legislature?

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30 Ibid, Finding 4.A.

A. That was a question many people asked in the beginning but as it turned out it was, in my opinion, a good decision for a number of reasons.

First, and not the least, the docket allowed the KCC to somewhat isolate itself from the debate and remain impartial. This became important as their opinion was sought before the task force and it allowed commissioners to defer because there was an open matter under consideration. As the issues became increasingly contentious, and many of the proposals deferred details of implementation to the KCC, it also prevented the commissioners from being accused of prejudging the issues.

Second, because the issue had not been decided, it freed up commission staff to express their personal views publicly while making it clear they were not speaking on behalf of the commission."

Third, it allowed the KCC to collect utility and industry opinions and information and provide the results to the task force. Because the task force was a quasi-legislative body it followed legislative process, not the quasi-judicial regulatory process. What this means is that while parties frequently testify before legislative hearings in Kansas, they do not have to do so under oath. On the other hand the quasi-judicial regulatory process could gather sworn testimony.

Fourth, all of the proposals considered and debated by the task force included a large amount of decisions that were deferred to the KCC, assuming the legislation was enacted.

Finally, the KCC is a fee-based agency and by establishing a generic docket it was able to get the funds necessary to cover staff time and consultant fees.

Q. Who was primarily interested in promoting retail competition in Kansas?

A. At that time there were a few major manufacturers and a few utilities that supported the concept. Over the two years the task force met there was increasing support from the environmental community that saw the effort as a way to implement renewable energy and energy efficiency measures.

Q. What was the result of the retail wheeling task force's efforts?

A. In 1998 a retail wheeling bill was drafted by the task force and delivered to the legislature where it was met with little enthusiasm. The bill itself did not get passed out of a legislative committee and Kansas does not have retail competition today. Nonetheless the fact that the issue was debated, studied and discussed for several years was in itself a benefit. When the bill was finally drafted many of the parties that were enthusiastic at first realized the complexity of the issue. Additionally, many of the implementation details were left up to the KCC and, in my opinion, many of the early enthusiasts were not willing to continue battling their issues in the regulatory process.

Q. What were the major issues debated by the retail wheeling task force?

A. Primarily, They were the extent of stranded costs and how these costs would be recovered. As in Kentucky, the issue of stranded costs depended on the particular utility being studied.

Q. How are stranded costs defined?

A. The Kentucky study provides a concise description of the concept of stranded costs: "A utility's past investment costs or contractual obligations that are not recoverable in a competitive market."

Q. Do you have some examples of stranded costs?

A. In Kansas the primary example was costs related to the one nuclear plant. While the initial plant investment was expensive, the variable operating costs of the nuclear plant are low. Nonetheless deregulated market prices were predicted to allow recovery of the variable costs, but to "strand" the initial investment costs. In the Kentucky study the findings indicate that stranded costs were assumed to be incurred by utilities that had made major investments in coal generating plants. It was concluded that these utilities, including Big Rivers, would be able to recover their variable costs in a retail competition environment, but not the fixed investment costs.

Q. How did either the Kansas and Kentucky task forces propose to address stranded costs?

A. In Kansas the proposed legislation specifically tasked the KCC with the duty of identifying any stranded costs and developing non-bypassable transition costs that would be assigned to all utility customers. The Kentucky study recognized these transition costs as "stranded costs which are charged to a utility customer through some type of fee or surcharge."

Q. If a deregulated electric market creates stranded costs for excessive generation investment, how are these investments treated in a regulated market?

A. In a regulated electric market there are generally two key decisions. The first decision is whether or not the investment is needed, used and useful. For example, a utility may use a new generating plant, but if there were already adequate generation resources and the plant is not needed, the costs are often disallowed. The second decision is whether or not the investment was prudent and reasonable. Continuing the previous example, even if the new generating plant is needed, if the utility spent far more than was reasonable or prudent to obtain the resource, often a portion of these costs are disallowed.

Q. Please describe the costs related to unneeded Big Rivers' generation in a regulated and a deregulated context.

A. In this proceeding there are really two major possibilities. If Century ceases to operate entirely, Big Rivers will have a large amount of generation investment that is no longer needed or used and useful in the regulated environment. In that case the Commission must decide if Big Rivers' remaining customers will bear the additional costs. On the other hand, if Century continues to operate by purchasing power from the competitive market, Big Rivers will incur stranded costs and the Commission must consider whether or not Century will bear any of the transition costs.

Q. Does this conclude your testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS)
ELECTRIC CORPORATION, INC.) Case No. 2012-00535
FOR AN ADJUSTMENT OF RATES)

AFFIDAVIT OF LARRY HOLLOWAY

)
State of Kansas)
)

Larry Holloway, being first duly sworn, states the following: The prepared Pre-Filed Direct Testimony, and the Schedules and Appendix attached thereto constitute the direct testimony of Affiant in the above-styled case. Affiant states that he would give the answers set forth in the Pre-Filed Direct Testimony if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, his statements made are true and correct. Further affiant saith not.

Larry Holloway

SUBSCRIBED AND SWORN to before me this 2nd day of May, 2013.

Linda L. Meyer
NOTARY PUBLIC

My Commission Expires: LINDA L. MEYER Notary Public - State of Kansas My Appt. Expires 9-29-15

Exhibit Holloway-1

Qualifications of Larry W. Holloway, P.E.

Qualifications of Larry W. Holloway, P.E.

General

Electric industry professional with broad experience in public utility regulation, power plant operations, maintenance and performance testing, transmission service, resource planning, procurement and scheduling, utility load forecasting and planning, project management, and electric utility ratemaking.

Work History and Recent Relevant Experience

Kansas Power Pool (KPP) March 2009 - Present

Operations Manager

Preparation of annual budget, including load forecasts, purchase power and fuel costs, generation capacity costs, and pool wide rate design for a wholesale not for profit municipal energy agency that provides 34 municipal utilities with generation supplies and transmission service.

Responsible for securing generation resources and transmission service for KPP members. Oversight of administration of service contracts for transmission scheduling, Information technology, and metering services. Coordinating of regulatory services and responsible for expert testimony on transmission policy and services.

Kansas Corporation Commission (KCC) July 1993 to March 2009

Chief of Energy Operations

Provided electric utility industry expert testimony before the KCC as member of KCC Staff.in over 40 dockets, including dockets involving generating costs and performance,

.

Acted as Commission liaison before many groups including legislative committees, industrial groups, NARUC, environmental groups, civic organizations, utility groups, federal agencies, regional reliability councils, transmission organizations and state social agencies.

Provided presentations, courses and speeches on a variety of KCC and industry issues to many groups including legislative committees, regional transmission organizations, industry conferences and international regulatory bodies.

Wolf Creek Nuclear Plant -WCNOC — June 1989 to July 1993
BOP System Engineering Supervisor

Browns Ferry Nuclear Plant- TVA — August 1987 to June 1989
Senior System Engineer

Trojan Nuclear Plant - Portland General Electric — October 1984 to August 1987
System Engineer III

Wolf Creek Nuclear Plant - Matsco — April 1983 to October 1984
Contract Startup Engineer

Burns & Roe - WNP 2 — September 1982 to April 1983
Nuclear Design Engineer

Ebasco Inc - Waterford Nuclear Plant — June 1981 to September 1982
Construction Engineer

FMC Inc - Inorganic Chemical Plant — June 1979 to June 1981
Project Engineer

Kansas Power & Light - Natural Gas Division — June 1978 to June 1979
Field Engineer

Education

Univerity of Kansas, Kansas
Bachelor of Science Civil Engineering, December 1977
Bachelor of Science Mechanical Engineering, May 1978
Master of Science Mechanical Engineering, May 1997

Washington State University, Washington
Master of Engineering Management, May 1988

Professional Registration

Registered Professional Mechanical and Civil Engineer, State of Oregon, PE license No. 12989

Expert Witness Testimony

FERC	Provided analysis and affidavit in FERC Docket ER01-1305 for the KCC, which led to a negotiated settlement in an affiliate purchase power agreement between Westar Energy and Westar Generating Inc., and affiliate.
KCC	KCC Staff testimony in Docket Nos. 95-EPDE-043-COM, 96-KG&E-100-RTS, 96-WSRE-101-DRS, 96-SEPE-680-CON, 97-WSRE-676-MER, 98-KGSG-822-TAR, 99-WSRE-381-EGF, 99-WSRE-034-COM, 99-WPEE-818-RTS, 00-WCNE-154-GIE, 00-UCUE-677-MER, 01-WSRE-436-RTS, 01-WPEE-473-RTS, 01-KEPE-1106-RTS, 02-SEPE-247-RTS, 02-EPDE-488-RTS, 02-MDWG-922-RTS, 03-MDWE-001-RTS, 03-WCNE-178-GIE, 03-MDWE-421-ACQ, 03-KGSG-602-RTS, 04-AQLE-1065-RTS, 04-KCPE-1025-GIE, 05-EPDE-980-RTS, 05-WSEE-981-RTS, 06-WCNE-204-GIE, 06-SPPE-202-COC, 06-WSEE-203-GIE, 06-KCPE-828-RTS, 06-KGSG-1209-RTS, 06-MKEE-524-ACQ, 07-WSEE-616-PRE, 07-KCPE-905-RTS, 08-WSEE-309-PRE, 08-KMOE-028-COC, 08-WSEE-609-MIS, 08-MDWE-594-RTS, 08-WSEE-1041-RTS, 08-ITCE-936-COC, 09-KCPE-246-RTS, and 08-PWTE-1022-COC.
	Testimony on behalf of KPP in Docket Nos. 09-MKEE-969-RTS, 11-GIME-497-GIE, and 12-KPPE-630-MIS.

Exhibit Holloway-2

Frequency and Dates of Last Inspections

Note: Examples of Pressure Relief Devices are highlighted in yellow

Examples of HEP and HEP Supports are highlighted in green

Frequency and Dates of Last Inspections
From the Big Rivers Boiler Condition Spreadsheet provided in AG 1-140

Equipment (Section)	Tube Material & Size	PM Description	Frequency	Date of Last Inspection
Boiler (general)		Acquisition of tube samples, waterwalls, superheat and reheat	3 years or as needed	May-08
Economizer		Economizer Section, inspection and repair	3 years	Mar-05
Econ. Feed Piping (S)	8-5/8" OD x Sch. 140 SA 106 Gr. B			
Econ. Feed Piping (T)	6-5/8" OD x Sch. 160 SA 106 Gr. B			
Econ. Inlet Hdr.	10-3/4" OD x Sch. 140 SA106 Gr. C			
Econ. Elements	2" OD x 187 MW SA 210 W/ 4-5/8" & 5" Gills			
Econ. Outlet Hdr	6-5/8" OD x Sch. 160 SA106 Gr. C			
Drum		Drum, inspection and repair	yearly	May-08
		Magnetic Particle Testing	9 years	Apr-02
Drum Safeties	(1) - 2-1/2" Crosby HC85W	Complete disassemble, clean, inspection, lap disc & nozzle, set adjusting rings/overlap collar to manufacturers specs, reassemble and seal.	3 years	May-08
	(1) - 2-1/2" Consolidated 1739WB-2-S	Complete disassemble, clean, inspection, lap disc & nozzle, set adjusting rings/overlap collar to manufacturers specs, reassemble and seal.	3 years	May-08
	(1) - 3" Crosby HC85W	Complete disassemble, clean, inspection, lap disc & nozzle, set adjusting rings/overlap collar to manufacturers specs, reassemble and seal.	3 years	May-08
Downcomers				
Furnace RWW Downcomer	Unpierced Section - 12-3/4" OD x Sch. 120 SA 106 Gr. C			
	Pierced Section - 12-3/4" OD x 1-1/2" MW SA 106 Gr. C			
Furnace FWW Downcomer	Unpierced Section - 16" OD x Sch. 120 SA 106 Gr. C			
	Pierced Section - 16" OD x 1-3/4" MW SA 106 Gr. C			
Furnace SWW Downcomer	Unpierced Section - 14" OD x Sch. 120 SA 106 Gr. C			
	Pierced Section - 14" OD x 1-3/4" MW SA 106 Gr. C			
Waterwalls		Waterwall mapping and (NDE)	3 years	May-08
Lower Furn. Front, Rear, Side WW Hdr	8-5/8" OD x 1-5/16"MW SA 106 Gr. C			
Upper Furn. Front & Side WW Hdr	8-5/8" OD x 1-5/16"MW SA 106 Gr. C	UT waterwall drains		
Furnace Roof Hdr	10-3/4" OD x 1-1/8"MW SA 106 Gr. C			
Front WW	2-1/4" OD x 203 MW SA 178 Gr. C			
Side WW	2-1/4" OD x 203 MW SA 178 Gr. C			
Rear WW	2-1/4" OD x 203 MW SA 178 Gr. C			
Load Carry Tubes @ Screen	2-1/2" OD x 250 MW SA 210 Gr. A			
Furnace Roof	2-1/2" OD x 203 MW SA 178 Gr. C			
WW Feeder Tubes	4" OD x 319 MW SA 210 Gr. A-1			
WW Riser Tubes	4" OD x 319 MW SA 210 Gr. A-2			
Lower Arch	2-1/4" OD x 203 MW SA 178 Gr. C			
Knee Tubes	2-1/4" OD x 203 MW SA 178 Gr. C			
HRA		HRA sections, inspection and repair		
HRA Upper & Lower Side Wall Hdr	8-5/8" OD x 7/8" MW SA 106 Gr. C			
Partition Wall Tubes	1-3/4" OD x 165 MW SA 178 Gr. C			
	1-3/4" OD x 260 MW SA 210 Gr. A-1			
HRA Side Wall Tubes	1-3/4" OD x 165 MW SA 178 Gr. C			
	2" OD x 290 MW SA 210 Gr. A-1			
HRA Rear & Roof (RH Pass)	1-3/4" OD x 165 MW SA 178 Gr. C			
HRA Roof (SH Pass)	1-3/4" OD x 165 MW SA 178 Gr. C			
Steam Tubes				
Steam Supply Tubes	4" OD x 319 MW SA 210 Gr. A-1			
Transfer Tubes (Inlet & Outlet Spray Hdr)	Inlet - 4" OD x 380 MW SA 213 T12			
	Outlet - 4" OD x 338 MW SA 209 T12			
Distributing Tubes (Prim. SH Inlet Hdr to HRA Side Wall Hdr)	2-1/4" OD x 220 MW SA 178 Gr. C			
Primary Superheat (Convection)		Superheat sections, inspection and repair	3 years	May-08
SH Inlet Hdr	8-5/8" OD x 7/8" MW SA 106 Gr. C			
Inlet Assembly	2-1/4" OD x 220 MW SA 178 Gr. C			
Conv. SH Intermediate Hdr	12-3/4" OD x 1-5/16" MW SA 106 Gr. C			
Intermediate Assembly	2-1/4" OD x 280 MW SA 210 Gr. A-1			
Outlet Assembly	2" OD x 244 MW SA 210 Gr. A-1			
Conv. SH Outlet Hdr	16" OD x 2-1/4" MW SA 106 Gr. C			
Conv. SH Transfer Pipe (Lower Sprays)	14" OD x Sch. 140 SA 106 Gr. C			

Frequency and Dates of Last Inspections
From the Big Rivers Boiler Condition Spreadsheet provided in AG 1-140

Equipment (Section)	Tube Material & Size	PM Description	Frequency	Date of Last Inspection
Platen Superheater (Division Wall)		Superheat sections, inspection and repair	3 years	May-08
Division Wall Inlet Hdr	16" OD x 2-1/4" MW SA 106 Gr. C			
Inlet Assembly	2" OD x 180 MW SA 178 Gr. C			
Intermediate Assembly	2" OD x 375 MW SA 213 T22			
Outlet Assembly	2" OD x 188 MW SA 213 T12			
Division Wall Outlet Hdr	8-5/8" OD x 1-1/4"MW SA 335 P12			
Finish Superheat (Pendent)		Superheat sections, inspection and repair	3 years	May-08
Spray Control Hdr - Unpierced Section (Upper Sprays)	16" OD x Sch. 160 SA 335 P11	Boroscope header and inspect nozzle		
Spray Control Hdr - Pierced Section (Upper Sprays)	16" OD x 1-3/4" MW SA 335 P11	Boroscope header and inspect nozzle		
Inlet Header Tubes	2" OD x 165 MW SA 213 T12			
Pendent SH Inlet Hdr	14 OD x 1-3/8" MW SA 335 P11			
Inlet Assembly	2-1/4" OD x 320 MW SA 213 T22			
Outlet Assembly	2-1/4" OD x 417 MW SA 213 T22			
Outlet Header Tubes	2" OD x 283 MW SA 213 T22			
Pendent SH Outlet Hdr	23-1/2" OD x 3-5/16" MW (16-1/2" Min ID) SA 335 P22			
Superheat Safeties	Crosby 3M6 HCA-78A	Complete disassemble, clean, inspection, lap disc & nozzle, set adjusting rings/overlap collar to manufacturers specs, reassemble and seal.	3 years	May-08
	Crosby 2-1/2" HPV-78W	Complete disassemble, clean, inspection, lap disc & nozzle, set adjusting rings/overlap collar to manufacturers specs, reassemble and seal.	3 years	May-08
Reheater		Reheat Section, inspection and repair	3 years	May-08
Reheater Inlet Hdr	24" OD x Sch. 160 SA 106 Gr. B			
Inlet Assembly	2-1/4" OD x 150 MW SA 178 Gr. C			
Lower Assembly	2-1/4" OD x 150 MW SA 213 T2			
Intermediate Assembly	2-1/4" OD x 150 MW SA 213 T12			
Upper Assembly	2-1/4" OD x 150 MW SA 213 T22			
Outlet Assembly	2" OD x 156 MW SA 213 T22			
Reheater Outlet Hdr	22" OD x 1-5/16" MW (21-3/4" Min. ID) SA 387 Gr. D			
Reheater Safeties				
Reheat Inlet	(2) - 4" Crosby 4Q8-HC26W	Complete disassemble, clean, inspection, lap disc & nozzle, set adjusting rings/overlap collar to manufacturers specs, reassemble and seal.	3 years	May-08
Reheat Inlet	(1) - 6" Crosby 6R8-HC26W	Complete disassemble, clean, inspection, lap disc & nozzle, set adjusting rings/overlap collar to manufacturers specs, reassemble and seal.	3 years	May-08
Reheat Outlet	(1) - 4" Crosby 4Q8-HCA28W	Complete disassemble, clean, inspection, lap disc & nozzle, set adjusting rings/overlap collar to manufacturers specs, reassemble and seal.	3 years	May-08
Headers	Listed with Boiler Section	Boroscope, Mag. Particle, Hardness Testing, Replications, OD measurements	9 years	Apr-02

Frequency and Dates of Last Inspections
From the Big Rivers Boiler Condition Spreadsheet provided in AG 1-140

Equipment (Section)	Tube Material & Size	PM Description	Frequency	Date of Last Inspection
High Energy Piping and Hangers				
Main Steam Inlet to Turbine after Wye	10.75" OD x 1-9/16" AW SA 335 P22	Plastic Replications, MT/PT nozzles and attachments, and Guided Ultrasonic Inspection, and UT high energy piping	3 years	May-08
Main Steam Line	15.25" OD x 1-7/8" MW	Plastic Replications, MT/PT nozzles and attachments, and Guided Ultrasonic Inspection, and UT high energy piping	3 years	May-08
Main Steam Line Hangers	12 hangers	Inspection of hangers, cold and hot settings, adjustments, MT hangers	3 years	May-08
Cold Reheat outlet from Turbine to Wye	16" OD x .500 MW	Plastic Replications, MT/PT nozzles and attachments, and Guided Ultrasonic Inspection, and UT high energy piping	3 years	May-08
Cold Reheat Line	22" OD x .625 MW	Plastic Replications, MT/PT nozzles and attachments, and Guided Ultrasonic Inspection, and UT high energy piping	3 years	May-08
Cold Reheat Line Hangers	11 hangers	Inspection of hangers, cold and hot settings, adjustments, MT hangers	3 years	May-08
Hot Reheat Steam Inlet to Turbine after Wye	16" OD x .844 NW SA 335 P22	Plastic Replications, MT/PT nozzles and attachments, and Guided Ultrasonic Inspection, and UT high energy piping	3 years	May-08
Hot Reheat Line	22" OD x .983 MW	Plastic Replications, MT/PT nozzles and attachments, and Guided Ultrasonic Inspection, and UT high energy piping	3 years	May-08
Hot Reheat Line Hangers	9 hangers	Inspection of hangers, cold and hot settings, adjustments, MT hangers	3 years	May-08

Frequency and Dates of Last Inspections
From the Big Rivers Boiler Condition Spreadsheet provided in AG 1-140

Equipment (Section)	Tube Material & Size	PM Description	Frequency	Date of Last Inspection
Boiler (general)		Acquisition of tube samples, waterwalls, superheat and reheat	3 years or as needed	May-07
Economizer		Economizer Section, inspection and repair	3 years	May-07
Econ. Feed Piping (S)	8-5/8" OD x Sch. 140 SA 106 Gr. B			
Econ. Feed Piping (T)	6-5/8" OD x Sch. 160 SA 106 Gr. B			
Econ. Inlet Hdr.	10-3/4" OD x Sch. 140 SA106 Gr. C			
Econ. Elements	2" OD x 187 MW SA 210 W/ 4-5/8" & 5" Gills			
Econ. Outlet Hdr	6-5/8" OD x Sch. 160 SA106 Gr. C			
Drum		Drum, inspection and repair	yearly	Feb-09
		Magnetic Particle Testing	9 years	Mar-02
Drum Safeties				
Drum Safeties	(2) - 2-1/2" Crosby HC85W	Complete disassemble, inspection and repair	3 years	May-07
	(1) - 3" Crosby HC85W	Complete disassemble, inspection and repair	3 years	May-07
Downcomers				
Furnace RWW Downcomer	Unpierced Section - 12-3/4" OD x Sch. 120 SA 106 Gr. C			
	Pierced Section - 12-3/4" OD x 1-1/2" MW SA 106 Gr. C			
Furnace FWW Downcomer	Unpierced Section - 16" OD x Sch. 120 SA 106 Gr. C			
	Pierced Section - 16" OD x 1-3/4" MW SA 106 Gr. C			
Furnace SWW Downcomer	Unpierced Section - 14" OD x Sch. 120 SA 106 Gr. C			
	Pierced Section - 14" OD x 1-3/4" MW SA 106 Gr. C			
Waterwalls		Waterwall mapping and (NDE)	3 years	May-07
Lower Furn. Front, Rear, Side WW Hdr	8-5/8" OD x 1-5/16"MW SA 106 Gr. C			
Upper Furn. Front & Side WW Hdr	8-5/8" OD x 1-5/16"MW SA 106 Gr. C			
Furnace Roof Hdr	10-3/4" OD x 1-1/8"MW SA 106 Gr. C			
Front WW	2-1/4" OD x 203 MW SA 178 Gr. C			
Side WW	2-1/4" OD x 203 MW SA 178 Gr. C			
Rear WW	2-1/4" OD x 203 MW SA 178 Gr. C			
Load Carry Tubes @ Screen	2-1/2" OD x 250 MW SA 210 Gr. A			
Furnace Roof	2-1/2" OD x 203 MW SA 178 Gr. C			
WW Feeder Tubes	4" OD x 319 MW SA 210 Gr. A-1			
WW Riser Tubes	4" OD x 319 MW SA 210 Gr. A-2			
Lower Arch	2-1/4" OD x 203 MW SA 178 Gr. C			
Knee Tubes	2-1/4" OD x 203 MW SA 178 Gr. C			
HRA				
HRA Upper & Lower Side Wall Hdr	8-5/8" OD x 7/8" MW SA 106 Gr. C			
Partition Wall Tubes	1-3/4" OD x 165 MW SA 178 Gr. C			
	1-3/4" OD x 260 MW SA 210 Gr. A-1			
HRA Side Wall Tubes	1-3/4" OD x 165 MW SA 178 Gr. C			
	2" OD x 290 MW SA 210 Gr. A-1			
HRA Rear & Roof (RH Pass)	1-3/4" OD x 165 MW SA 178 Gr. C			
HRA Roof (SH Pass)	1-3/4" OD x 165 MW SA 178 Gr. C			
Steam Tubes				
Steam Supply Tubes	4" OD x 319 MW SA 210 Gr. A-1			
Transfer Tubes (Inlet & Outlet Spray Hdr)	*Inlet - 4" OD x 380 MW SA 213 T12*			
	Outlet - 4" OD x 338 MW SA 209 T12			
Distributing Tubes (Prim. SH Inlet Hdr to HRA Side Wall Hdr)	2-1/4" OD x 220 MW SA 178 Gr. C			

Frequency and Dates of Last Inspections
From the Big Rivers Boiler Condition Spreadsheet provided in AG 1-140

Equipment (Section)	Tube Material & Size	PM Description	Frequency	Date of Last Inspection
Primary Superheat (Convection)		Superheat sections, inspection and repair	3 years	May-07
SH Inlet Hdr	8-5/8" OD x 7/8" MW SA 106 Gr. C			
Inlet Assembly	2-1/4" OD x 220 MW SA 178 Gr. C			
Conv. SH Intermediate Hdr	12-3/4" OD x 1-5/16" MW SA 106 Gr. C			
Intermediate Assembly	2-1/4" OD x 280 MW SA 210 Gr. A-1			
Outlet Assembly	2" OD x 244 MW SA 210 Gr. A-1			
Conv. SH Outlet Hdr	16" OD x 2-1/4" MW SA 106 Gr. C			
Conv. SH Transfer Pipe (Lower Sprays)	14" OD x Sch. 140 SA 106 Gr. C			
Platen Superheater (Division Wall)		Superheat sections, inspection and repair	3 years	May-07
Division Wall Inlet Hdr	16" OD x 2-1/4" MW SA 106 Gr. C			
Inlet Assembly	2" OD x 180 MW SA 178 Gr. C			
Intermediate Assembly	2" OD x 375 MW SA 213 T22			
Outlet Assembly	2" OD x 188 MW SA 213 T12			
Division Wall Outlet Hdr	8-5/8" OD x 1-1/4"MW SA 335 P12			
Finish Superheat (Pendent)		Superheat sections, inspection and repair	3 years	May-07
Spray Control Hdr - Unpierced Section (Upper Sprays)	16" OD x Sch. 160 SA 335 P11			
Spray Control Hdr - Pierced Section (Upper Sprays)	16" OD x 1-3/4" MW SA 335 P11			
Inlet Header Tubes	2" OD x 165 MW SA 213 T12			
Pendent SH Inlet Hdr	14 OD x 1-3/8" MW SA 335 P11			
Inlet Assembly	2-1/4" OD x 320 MW SA 213 T22			
Outlet Assembly	2-1/4" OD x 417 MW SA 213 T22			
Outlet Header Tubes	2" OD x 283 MW SA 213 T22			
Pendent SH Outlet Hdr	23-1/2" OD x 3-5/16" MW (16-1/2" Min ID) SA 335 P22			
Superheat Safeties	Crosby 3M6 HCA-78A	Complete disassemble, inspection and repair	3 years	May-07
	Crosby 2-1/2" HPV-78W	Complete disassemble, inspection and repair	3 years	May-07
Reheater		Reheat Section, inspection and repair	3 years	May-07
Reheater Inlet Hdr	24" OD x Sch. 160 SA 106 Gr. B			
Inlet Assembly	2-1/4" OD x 150 MW SA 178 Gr. C			
Lower Assembly	2-1/4" OD x 150 MW SA 213 T2			
Intermediate Assembly	2-1/4" OD x 150 MW SA 213 T12			
Upper Assembly	2-1/4" OD x 150 MW SA 213 T22			
Outlet Assembly	2" OD x 156 MW SA 213 T22			
Reheater Outlet Hdr	22" OD x 1-5/16" MW (21-3/4" Min. ID) SA 387 Gr. D			
Reheater Safeties				
Reheat Inlet	(2) - 4" Crosby 4Q8-HC26W	Complete disassemble, inspection and repair	3 years	May-07
Reheat Inlet	(1) - 6" Crosby 6R8-HC26W	Complete disassemble, inspection and repair	3 years	May-07
Reheat Outlet	(1) - 4" Crosby 4Q8-HCA28W	Complete disassemble, inspection and repair	3 years	May-07
Headers	Listed with Boiler Section	Boroscope, Mag. Particle, Hardness Testing, Replications, OD measurements	9 years	Mar-02

Frequency and Dates of Last Inspections
From the Big Rivers Boiler Condition Spreadsheet provided in AG 1-140

Equipment (Section)	Tube Material & Size	PM Description	Frequency	Date of Last Inspection
High Energy Piping and Hangers				
Main Steam Inlet to Turbine after Wye	10.75" OD x 1-9/16" AW SA 335 P22	Plastic Replications, MT/PT nozzles and attachments, and Guided Ultrasonic Inspection	3 years	May-07
Main Steam Line	15.25" OD x 1-7/8" MW	Plastic Replications, MT/PT nozzles and attachments, and Guided Ultrasonic Inspection	3 years	May-07
Main Steam Line Hangers	12 hangers	Inspection of hangers, cold and hot settings, adjustments, MT hangers	3 years	May-07
Cold Reheat outlet from Turbine to Wye	16" OD x .500 MW	Plastic Replications, MT/PT nozzles and attachments, and Guided Ultrasonic	3 years	May-07
Cold Reheat Line	22" OD x .625 MW	Plastic Replications, MT/PT nozzles and attachments, and Guided Ultrasonic Inspection	3 years	May-07
Cold Reheat Line Hangers	11 hangers	Inspection of hangers, cold and hot settings, adjustments, MT hangers	3 years	May-07
Hot Reheat Steam Inlet to Turbine after Wye	16" OD x .844 NW SA 335 P22	Plastic Replications, MT/PT nozzles and attachments, and Guided Ultrasonic Inspection	3 years	May-07
Hot Reheat Line	22" OD x .983 MW	Plastic Replications, MT/PT nozzles and attachments, and Guided Ultrasonic Inspection	3 years	May-07
Hot Reheat Line Hangers	9 hangers	Inspection of hangers, cold and hot settings, adjustments, MT hangers	3 years	May-07

Frequency and Dates of Last Inspections
From the Big Rivers Boiler Condition Spreadsheet provided in AG 1-140

Equipment (Section)	Tube Material & Size	PM Description	Frequency	Date of Last Inspection
Boiler (general)		Acquisition of tube samples, waterwalls, superheat and reheat	3 years or as needed	Jun-09
Economizer		Economizer Section, inspection and repair	3 years	Jun-09
Economizer Inlet Header	10-3/4" OD x 1.125" AW SA 106C			
Economizer Feed Pipe to Drum	10-3/4" OD x 1.125" AW SA 106C			
Terminal Tubes @ Inlet/Outlet Hdr	2-1/2" OD x 220 MW SA 210			
Econ. Assemblies	2-1/2" OD x 250 MW SA 210			
Economizer Outlet Header	10-3/4" OD x 1.125" AW SA 106C			
Drum	60" ID x 4.749" MW	Drum, inspection and repair	yearly	Jun-09
		Magnetic Particle Testing	9 years	Fall-98
	Heads - 60" OD x 4.125" MW			
Drum Safeties	(3) - 3" -2500# Consolidated 1759WA (3"x5"x6")	Complete disassemble, inspection and repair	3 years	Jun-09
Downcomers	16" OD x 320 MW SA 106C			
Waterwalls		Waterwall mapping and (NDE)	3 years	Jun-09
Side Water Feeder Tubes	5" OD x 380 MW SA 210			
Sidewalls	2-1/2" OD x 203 MW SA 178C			
Knee Tubes (Deflector)	3" OD x 240 MW SA 178C			
Lower Arch	2-1/2" OD x 203 MW SA 178C			
Roof Tubes	2-1/2" OD x 203 MW SA 178C			
Convection Side Walls	2-1/2" OD x 240 MW SA 210			
Upper Side WW Hdr	8-5/8" OD x 1.25" AW SA 106C			
Lower Side WW Hdr	8-5/8" OD x 1.25" AW SA 106C			
Upper Front WW Hdr	8-5/8" OD x 1.25" AW SA 106C			
Roof Releaser Hdr	8-5/8" OD x 1.25" AW SA 106C			
Upper Furnace Rear WW Hdr	10-3/4" OD x 1.375 AW SA 106C			
Upper Conv. Rear WW Hdr	8-5/8" OD x 1.25" AW SA 106C			
Front Hopper Hdr	18-1/2" OD x 2.375" MW SA 106C			
Rear Hopper Hdr	18-1/2" OD x 2.375" MW SA 106C			
Side Hopper Hdr	16" OD x 2" MW SA 106C			
Primary Superheat		Superheat sections, inspection and repair	3 years	Jun-09
Primary Feeder Hdr				
Primary Superheater Inlet Header	10-3/4" OD x 1.375" AW SA 106C			
Primary Superheater Tubes	2-1/2" OD x 203 MW SA 178C			
	2-1/2" OD x 240 MW SA 178C			
	2-1/2" OD x 300 MW SA 210			
	2-1/2" OD x 281 MW SA 209 T1			
	2-1/4" OD x 203 MW SA 213 T11			
Primary Superheater Outlet Header	14" OD x 1.375" MW SA 335 P11			
Superheat Piping	Crossover Piping - 12-3/4" Od x 1.312" AW SA 335 P11			
	Terminal Piping - 16" OD x 2.125" MW SA 335 P22			
Superheat Safeties	Consolidated - 1738WD, 1533YX	Complete disassemble, inspection and repair	3 years	Jun-09

Frequency and Dates of Last Inspections
From the Big Rivers Boiler Condition Spreadsheet provided in AG 1-140

Equipment (Section)	Tube Material & Size	PM Description	Frequency	Date of Last Inspection
Secondary Superheat (Radiant & Hi-Temp)		Superheat sections, inspection and repair	3 years	Jun-09
Secondary Superheat Spray Attemperators Hdr	12-3/4" OD x 1.312" AW SA 335 P11	Boroscope Header and Inspect nozzle	3 years	Jun-09
Secondary Superheater Inlet Hdr	16" OD x 1.375" MW SA 335 P11			
Secondary Superheater Tubes	2" OD x 180 MW SA 213 T11			
	2" OD x 180 MW SA 213 T1			
	1-3/4" OD x 156 MW SA 213 T11			
	2" OD x 203 MW SA 2123 T11			
	2" OD x 313 MW SA 213 T22			
	1-3/4" OD x 313 MW SA 213 T22			
	2" OD x 375 MW SA 213 T22			
Secondary Superheater Outlet Hdr	8-5/8" OD x 1.25" MW SA 106C			
Superheat Safeties	2-1/2" - 2000# Consolidated 1738WD	Complete disassemble, inspection and repair	3 years	Jun-09
	2-1/2" - 2500# Consolidated 1533YX	Complete disassemble, inspection and repair	3 years	Jun-09
Reheater		Reheat Section, inspection and repair	3 years	Jun-09
Reheat Spray Attemperators Hdr	22" OD x SA 105 Gr.2	Boroscope Header and Inspect nozzle	3 years	Jun-09
Reheat Inlet Safeties	(4) - 600# Consolidated - 1775QWB, 1775QV13, 1785WB	Complete disassemble, inspection and repair	3 years	Jun-09
Reheat Inlet Header	16" OD x .656 AW SA 106B			
Reheat Inlet Extension Hdr	16" OD x .500 AW SA 106B			
Reheat Tubes	2-1/2" OD x 135 MW SA 178A			
	2" OD x 120 MW SA 213 T11			
	2" OD x 148 MW Sa 213 T22			
Reheat Outlet Header	22" OD x 1.25" MW SA 335 P2			
Reheat Outlet Safety	(1) - 600# Consolidated - 1775QWD	Complete disassemble, inspection and repair	3 years	Jun-09
Headers	Listed with Boiler Section	Boroscope, Mag. Particle, Hardness Testing, Replications, OD measurements	9 years	Fall-98
High Energy Piping				
Main Steam Line	15-1/4" OD x 2-1/16" AW SA 335 P22	Plastic Replications, MT/PT nozzles and attachments, and Guided Ultrasonic Inspection	3 years	Jun-09
Main Steam Inlet Header @ Turbine	15-1/4" OD x 2-1/16" AW SA 335 P22	Plastic Replications, MT/PT nozzles and attachments, and Guided Ultrasonic Inspection	3 years	Jun-09
Main Steam Line Hangers	10 hangers, 2 seismic restraints	Inspection of hangers, cold and hot settings, adjustments, MT hangers	3 years	Jun-09
Cold Reheat Header from Turbine to Wye	16" OD x .500" NW	Plastic Replications, MT/PT nozzles and attachments, and Guided Ultrasonic	3 years	Jun-09
Cold Reheat Header from Wye at turbine to Wye at boiler	22" OD x .750" MW	Plastic Replications, MT/PT nozzles and attachments, and Guided Ultrasonic Inspection	3 years	Jun-09
Cold Reheat Header after Wye to boiler inlet	16" OD x .500 MW	Plastic Replications, MT/PT nozzles and attachments, and Guided Ultrasonic Inspection	3 years	Jun-09
Cold Reheat Line Hangers	12 hangers, 4 seismic restraints	Inspection of hangers, cold and hot settings, adjustments, MT hangers	3 years	Jun-09
Hot Reheat Inlet Header to Turbine after Wye	16" OD x .844" NW SA 335 P22	Plastic Replications, MT/PT nozzles and attachments, and Guided Ultrasonic Inspection	3 years	Jun-09
Hot Reheat Line	22" OD x 1.125 MW	Plastic Replications, MT/PT nozzles and attachments, and Guided Ultrasonic Inspection	3 years	Jun-09
Hot Reheat Line Hangers	9 hangers, 3 seismic restraints	Inspection of hangers, cold and hot settings, adjustments, MT hangers	3 years	Jun-09

Frequency and Dates of Last Inspections

From the Big Rivers Boiler Condition Spreadsheet provided in AG 1-140

Equipment (Section)	Tube Size/Material	PM Description	Frequency	Date of Last Inspection
Boiler (general)		Acquisition of tube samples, waterwalls, superheat and reheat	2 years	Nov-11
Economizer Inlet Header	10.75" OD x 1.25" MW Thickness SA106B	Economizer Inlet Header Inspection	8 years	
Economizer	2.0" OD x .203" MW Thickness SA178A HF	Economizer Section, inspection and repair	2 years	Nov-11
Economizer Outlet Header	10.75" OD x 1.25" MW Thickness SA106B	Economizer Outlet Header Inspection	8 years	
Drum		Drum, inspection and repair	2 years	Nov-11
Drum Safeties	(3) Crosby size 3M6-HE-96W, (1) Crosby size 3M26-HE-96W	G1 Inspect & Reset all of the Boiler Safeties	4 years	Nov-11
Downcomers		Drum Piping Connections Inspections	8 years	
Waterwalls East and West	2.5" OD x .203" MW Thickness on 3" centers SA210A1	Waterwall mapping and (NDE)	2 years	Nov-11
Waterwalls North and South	2.5" OD x .203" MW Thickness on 3" centers SA210A1	Waterwall mapping and (NDE)	2 years	Nov-11
Boiler Knees	2.75" OD x .240" MW Thickness on 3" centers SA210A1	Waterwall mapping and (NDE) and B&W PSB Thermal Quenching	2 years	Nov-11
Furnace Arch	2.75" OD x .203" MW Thickness on 4" centers SA210A1	Waterwall mapping and (NDE)	2 years	Nov-11
Drum Safeties	3.0"O.D. x .245" MW SA209TA1 1.75" x .165 MW SA209TA1	Primary Superheater Section, inspection and repair	2 years	Nov-11
Primary Superheater Inlet Ring Header	10.75" OD SA-192	Primary Superheater Section, inspection and repair	2 years	Nov-11
Primary Superheater Inlet Bank	2.0" OD x .165" MW Thickness 2.5" OD x .284" MW Thickness SA178A	Primary Superheater Section, inspection and repair	2 years	Nov-11
Primary Superheater Intermediate Bank	2.0" OD x .275" MW Thickness 2.0" OD x .165" MW Thickness SA 213T2	Primary Superheater Section, inspection and repair	2 years	Nov-11
Primary Superheater Outlet Bank	2.5" OD x .345" MW Thickness 2.0" OD x .165" MW Thickness SA 213T2	Primary Superheater Section, inspection and repair	2 years	Nov-11
Primary Superheater Outlet Header	18.25" OD x 2.25" MW SA335P11	Primary Superheater Section, inspection and repair	2 years	Oct-08
Secondary Superheat Spray Attemperators		Secondary Superheat Spray Attemperators inspections	6 Years	Oct-08
Secondary Superheater Inlet	2.0" OD x .230" MW Thickness Lead Tube each bank SA213 TP304TH Other tubes SA209 T1A and SA 213T2	Superheat sections, inspection and repair	2 years	Nov-11
Secondary Superheater Intermediate	2.0" OD x .230" to .188" MW Thickness SA 213 T22	Superheat sections, inspection and repair	2 years	Nov-11
Secondary Superheater Outlet	1.75" OD x .316" MW Thickness SA213 T22	Superheat sections, inspection and repair	2 years	Nov-11
Main Steam Outlet Header	23.75 OD x 3.25" MW Thickness 25.5" OD x 4.125" MW Thickness SA-335P22	Big Rivers had B&W perform Hone and Glow test on Header. Inspection for ligament	8 years	Apr-07
Main Steam Safeties	(1) each - Crosby, size 3M6-HCA-98W, (1) each - Crosby size 2 1/2 K26-HCA-98W.	G1 Inspect & Reset all of the Boiler Safeties	4 years	Nov-11
Main Steam Inlet Header to Turbine after Wye	17.75 OD x 1.875" MW Thickness 15.0" OD x 1.125" MW Thickness SA-335P11	Inspect welds, monitor creep, inspect attachments	8 years	Apr-07
Main Steam Hangers		G1 inspect and adjust hangers, outage years perform inspection attachments on selected hangers	Annually	Hot Inspection April 2010 Cold Inspection Nov 11
Cold Reheat Safeties	(2) each - Crosby size 4Q8-HC-36W, (2) each - Crosby size 6R8-HC-36W.	G1 Inspect & Reset all of the Boiler Safeties	4 years	Nov-11
Cold Reheat Steam Hangers		G1 inspect and adjust hangers, outage years perform inspection attachments on selected hangers	Annually	Hot Inspection April 2010 Cold Inspection Nov 11
Reheat Inlet Header	27.5" OD x 1.625" MW Thickness SA-106C	Cold Reheat Inlet Header Inspection	8 years	
Reheat Inlet Bank	2.50" OD x .165" MW Thickness 2.50" OD x .180" MW Thickness SA178A	Reheat Inlet Section, inspection and repair	2 years	Nov-11
Reheat Intermediate Bank	2.50" OD x .203" MW Thickness 2.50" OD x .180" MW Thickness SA213 T38	Reheat Intermediate Section, inspection and repair	2 years	Nov-11
Reheat Outlet Bank	2.25" OD x .148" MW Thickness 2.25" OD x .188" MW Thickness SA213 T22	Reheat Outlet Section, inspection and repair	2 years	Nov-11
Reheat Outlet Header	28.75 OD x 2.25" MW Thickness 25.5" SA-335P22	Big Rivers had B&W perform Hone and Glow test on Header. Inspection for ligament cracking, none found	4 years	Feb-04
Reheat Outlet Safety	(1) each - Crosby size 6R8-HCA-38W	G1 Inspect & Reset all of the Boiler Safeties	4 years	Nov-11
Hot Reheat Inlet Header to Turbine after Wye	24" x1.067" MW A335 P22	Inspect welds, monitor creep, inspect attachments	4 years	Apr-07
Hot Reheat Steam Hangers		G1 inspect and adjust hangers, outage years perform inspection attachments on selected hangers	Annually	Hot Inspection April 2010 Cold Inspection Nov 11

Equipment (Section)	Tube Size/Material	PM Description	Frequency	Date of Last Inspection
Boiler (general)		Acquisition of tube samples, waterwalls, superheat and reheat	2 years	May-09
Economizer Inlet Header	10.75" OD x 1.25" MW Thickness SA106B	Economizer Inlet Header Inspection	8 years	
Economizer	2.0" OD x .203" MW Thickness SA178A HF	Economizer Section, inspection and repair	2 years	May-09
Economizer Outlet Header	10.75" OD x 1.25" MW Thickness SA106B	Economizer Outlet Header Inspection	8 years	
Drum		Drum, inspection and repair	2 years	May-09
Drum Safeties	(3) Crosby size 3M6-HE-96W, (1) Crosby size 3M26-HE-96W	G1 Inspect & Reset all of the Boiler Safeties	4 years	May-09
Downcommers		Drum Piping Connections Inspections		
Waterwalls East and West	2.5" OD x .203" MW Thickness on 3" centers SA210A1	Waterwall mapping and (NDE)	2 years	May-09
Waterwalls North and South	2.5" OD x .203" MW Thickness on 3" centers SA210A1	Waterwall mapping and (NDE)	2 years	May-09
Boiler Knees	2.75" OD x .240" MW Thickness on 3" centers SA210A1	Waterwall mapping and (NDE) and B&W PSB Thermal Quenching	2 years	May-09
Furnace Arch	2.75" OD x .203" MW Thickness on 4" centers SA210A1	Waterwall mapping and (NDE)	2 years	May-09
Drum Safeties	3.0"O.D. x .245" MW SA209TA1 1.75" x .165 MW SA209TA1	Primary Suiperheater Section, inspection and repair	2 years	May-09
Primary Superheater Inlet Ring Header	10.75" OD SA-192	Primary Suiperheater Section, inspection and repair	2 years	May-09
Primary Superheater Inlet Bank	2.0" OD x .165" MW Thickness 2.5" OD x .284" MW Thickness SA178A	Primary Suiperheater Section, inspection and repair	2 years	May-09
Primary Superheater Intermediate Bank	2.0" OD x .275" MW Thickness 2.0" OD x .165" MW Thickness SA 213T2	Primary Suiperheater Section, inspection and repair	2 years	May-09
Primary Superheater Outlet Bank	2.5" OD x .345" MW Thickness 2.0" OD x .165" MW Thickness SA 213T2	Primary Suiperheater Section, inspection and repair	2 years	May-09
Primary Superheater Outlet Header	18.25" OD x 2.25" MW SA335P11	Primary Suiperheater Section, inspection and repair	2 years	May-09
Secondary Superheat Spray Attemperators		Secondary Superheat Spray Attemperators inspections	6 Years	May-09
Secondary Superheater Inlet	2.0" OD x .230" MW Thickness Lead Tube each bank SA213 TP304TH Other tubes SA209 T1A and SA 213T2	Superheat sections, inspection and repair	2 years	May-09
Secondary Superheater Intermediate	2.0" OD x .230" to .188" MW Thickness SA 213 T22	Superheat sections, inspection and repair	2 years	May-09
Secondary Superheater Outlet	1.75" OD x .316" MW Thickness SA213 T22	Superheat sections, inspection and repair	2 years	May-09
Main Steam Outlet Header	23.75 OD x 3.25" MW Thickness 25.5" OD x 4.125" MW Thickness SA-335P22	Secondary Superheater Outlet Header	4 years	Apr-07
Main Steam Safeties	(1) each - Crosby, size 3M6-HCA-98W, (1) each - Crosby size 2 1/2 K26-HCA-98W.	G2 Inspect & Reset all of the Boiler Safeties	4 years	May-09
Main Steam Inlet Header to Turbine after Wye	17.75 OD x 1.875" MW Thickness 15.0" OD x 1.125" MW Thickness SA-335P11	Inspect welds, monitor creep, inspect attachments	4 years	Apr-07
Main Steam Hangers		G2 inspect and adjust hangers, outage years perform inspection attachments on selected hangers	Annually	Hot Inspection Oct 08 Cold Inspection Apr-09
Cold Reheat Safeties	(2) each - Crosby size 4Q8-HC-36W, (2) each - Crosby size 6R8-HC-36W.	G2 Inspect & Reset all of the Boiler Safeties	4 years	Apr-05
Cold Reheat Steam Hangers		G2 inspect and adjust hangers, outage years perform inspection attachments on selected hangers	Annually	Hot Inspection Oct 08 Cold Inspection Apr-09
Reheat Inlet Header	27.5" OD x 1.625" MW Thickness SA-106C	Cold Reheat Inlet Header Inspection	4 years	
Reheat Inlet Bank	2.50" OD x .165" MW Thickness 2.50" OD x .180" MW Thickness SA178A	Reheat Inlet Section, inspection and repair	2 years	May-09
Reheat Intermediate Bank	2.50" OD x .203" MW Thickness 2.50" OD x .180" MW Thickness SA213 T38	Reheat Intermediate Section, inspection and repair	2 years	May-09
Reheat Outlet Bank	2.25" OD x .148" MW Thickness 2.25" OD x .188" MW Thickness SA213 T22	Reheat Outlet Section, inspection and repair	2 years	May-09
Reheat Outlet Header	28.75 OD x 2.25" MW Thickness 25.5" SA-335P22	Reheat Outlet header, inspection and repair	4 years	
Reheat Outlet Safety	(1) each - Crosby size 6R8-HCA-38W	G2 Inspect & Reset all of the Boiler Safeties	4 years	Apr-05
Hot Reheat Inlet Header to Turbine after Wye	24" O.D. x 1.067" MW A335 P22	Inspect welds, monitor creep, inspect attachments	4 years	Apr-05
Hot Reheat Steam Hangers		G2 inspect and adjust hangers, outage years perform inspection attachments on selected hangers	Annually	Hot Inspection Oct 08 Cold Inspection Apr-09

Frequency and Dates of Last Inspections
From the Big Rivers Boiler Condition Spreadsheet provided in AG 1-140

Equipment (Section)	Tube Size/Material	PM/Work Order Description	Frequency	Date of Last Inspection
Boiler (general)		PM-OUTAGE H-1 OBTAIN A TUBE SAMPLE from - Acquisition of tube samples, waterwalls, superheat and reheat	2 years	Apr-12
Economizer	2.5" O.D. x .250 MW SA-210 A1		2 years	Apr-12
Inlet Header	10.75" O.D. x 1.125" Av. Wall / SA-106- Gr. C	H-1 BOILER HEADER CONDITION ASSESSMENT - INSPECT THE HIGH TEMP REHEAT OUTLET HEADER, THE RADIANT SUPERHEAT OUTLET HEADER, THE ECONOMIZER INLET AND THE LOWER WW HEADERS AS PER RFQH-11-111, PO: 204368		Apr-12
Outlet Header	10.75" O.D. x 1.125" Av. Wall / SA-106- Gr. C	H-1 BOILER HEADER CONDITION ASSESSMENT - INSPECT THE HIGH TEMP REHEAT, THE RADIANT SUPERHEAT, THE ECONOMIZER INLET AND THE ECONOMIZER OUTLET HEADERS AS PER RFQH-08-176		Mar-09
Drum		PM-OUTAGE H-1 18 MO DRUM INSPECT FOR BLR. PERMIT RENEWAL	2 years	Apr-12
Furnace Waterwalls				Apr-12
Sidewalls Front Wall Rear Wall	2.5" O.D. x .203 MW / SA-178 Gr. C	Waterwall mapping and (NDE)	2 years	Apr-12
		Boiler Chemical Clean	10 years	Dec. 05
Knee Tubes	2.5" O.D. x .203 MW / SA-178 Gr. C	na	2	Apr-12
Rear WW deflection tubes	3.0" O.D. x .240 MW / SA-178 Gr. C	PM-OUTAGE H-1 OBTAIN TIGHT WIRE OF RWW DEFLECTION TUBES	2	Apr-12
Waterwall Headers		na	na	Apr-12
Drum Safeties	8.625" O.D. x 1.250" Thk. / SA-106 Gr. C			
Lower Furnace Side WW Header	8.625" O.D. x 1.250" Thk. / SA-106 Gr. C			
Front WW Release Header	8.625" O.D. x 1.250" Thk. / SA-106 Gr. C	PM-OUTAGE H-1 DYE CHECK SOUTH WATER WALL HEADER TUBES		Apr-12
Roof Release Header	8.625" O.D. x 1.250" Thk. / SA-106 Gr. C			
Furnace Rear WW Releaser Header	10.750" O.D. x 1.3750" Thk. / SA-106 Gr. C			
Convection Rear WW Release Header	8.625" O.D. x 1.250" Thk. / SA-106 Gr. C			
Downcomers	16" O.D. x 1.218" Thk. / SA-106 Gr. C			
Furnace Rear Hopper Header	18.5" O.D. x 2.375" Thk. / SA-106 Gr. C			
Furnace Side Hopper Header	16" O.D. x 2.000" Thk. / SA-106 Gr. C			
Primary Superheater			2 years	Apr-12
Upleg Assemblies	2.5" O.D. x .203 MW / SA 178 Gr. C			
Inlet Header	10.75" O.D. x 1.375" Thk. / SA-106- Gr. C			
Outlet Header	14" O.D. x 1.375" Thk. / SA-335 P11			
Radiant Superheater (High Temp. Superheater) Inlet Section	1.75 O.D. x .156" Thk / SA-213 T22	PM-H-1 OUTAGE INSPECTION OF RADIANT SUPERHEATER INLET	2 years	Apr-12
Outlet Section	1.75 O.D. x .313" Thk / SA-213 T22	PM-H-1 OUTAGE INSPECTION OF RADIANT SUPERHEATER OUTLET SECTION	2 years	Apr-12
Main Steam Inlet Header	16" O.D. x 1.375" Thk. / SA-335 P11			
Main Steam Outlet Header	16" O.D. x 2.5" Thk. / SA-335 P22	H-1 BOILER HEADER CONDITION ASSESSMENT - INSPECT THE HIGH TEMP REHEAT, THE RADIANT SUPERHEAT, THE ECONOMIZER INLET AND THE ECONOMIZER OUTLET HEADERS AS PER RFQH-08-176	4 years - This is based on the Riley report from 2009	Apr-12
East Superheat Spray Attemperator		PM-OUTAGE - INPSECT H-1 EAST SUPERHEAT SPRAY ATTEMPERATOR	6 year	Mar. 09
West Superheat Spray Attemperator		PM-OUTAGE - INPSECT H-1 WEST SUPERHEAT SPRAY ATTEMPERATOR	6 years	Mar. 09

Equipment (Section)	Tube Size/Material	PM/Work Order Description	Frequency	Date of Last Inspection
High Temperature Reheater Inlet Bank (Primary Reheater)	2.5" O.D. x .135 MW / SA-178 Gr. A	PM-H-1 OUTAGE INSPECTION OF HIGH TEMP REHEATER	2 years	Apr-12
High Temperature Reheater Intermediate Bank	2" O.D. x .120 MW / SA 213 T11			Apr-12
High Temperature Reheater Outlet Bank	2" O.D. x .148 MW / SA 213 T22			Apr-12
Reheat Inlet Header	16" O.D. x .656 Avg. Thk. / SA-106 Gr. B			
Reheat Outlet Header	22" O.D. x 1.250' Thk. / SA-335 P22	H-1 BOILER HEADER CONDITION ASSESSMENT - INSPECT THE HIGH TEMP REHEAT OUTLET HEADER, THE RADIANT SUPERHEAT OUTLET HEADER, THE ECONOMIZER INLET AND THE LOWER WW HEADERS AS PER RFQH-11-111, PO: 204368		Apr-12
East Reheat Spray Attemperator		PM-OUTAGE - INPSECT H-1 EAST REHEAT SPRAY ATTEMPERATOR	6 year	
West Reheat Spray Attemperator		PM-OUTAGE - INPSECT H-1 WEST REHEAT SPRAY ATTEMPERATOR	6 years	
High Energy Pipe Hangers				
Hot Reheat Pipe Hangers				Mar- 11
Cold Reheat Pipe Hangers				Mar- 11
Main Steam Pipe Hangers				Mar- 11
Boiler Safeties		PM-OUTAGE H-1 INSPECTION OF BOILER SAFETY VALVES	4 years	Mar- 11
North West Drum Safety	Size 3", Style 3-1759WA-2-S, Set 2200, Shop # BN6139, Capacity 383,700 #/hr.;		4 years	Mar- 11
South West Drum Safety	Size 3", Style 3-1759WA-2-S, Set @ 2230, Shop # BN6140, Capacity 348,400 #/hr.		4 years	Mar- 11
East Drum Safety	Size 3", Style 3-1759WA-1-S, Set 2260, Shop # BN6349, Capacity 420,500 #/hr		4 years	Mar- 11
Superheat Steam Line Safety	Size 2-1/2", Style 1738WD-1-S, Set 2040, and Shop #BN6142, Capacity 201,856 #/hr		4 years	Mar- 11
Reheater Safety Valve #1	Size 4", Style 4-1755QWD-1-S, Set 535, Shop # BN6354, Capacity 214,510 #/hr		4 years	Mar- 11
Reheater Safety Valve # 2	Size 4", Style 4-1775-QWB-1-S, Set 580, Shop # BN6351, Capacity 265,698 #/hr		4 years	Mar- 11
Reheater Safety Valve #3	Size 4", Style 4-1775-QWB-1-S, Set 595, Shop # BN6144, Capacity 272,353 #/hr		4 years	Mar- 11
Reheater Safety Valve #4	Size 6", Style 6-1705-RWB-1-S, Set 610 Shop # BN6353, Capacity 404,115 #/hr		4 years	Mar- 11
Sootblower system safety	Size 2" x 3", Style 1922HT, Set 600, Shop # TC 61363, Capacity 26,480		4 years	Mar- 11
Low Pressure Header System Safety	Size 4"x 6", Style 1910NC, Set 125, Shop # BM9421701, Capacity 33,665.5 #/hr, Serial # 1H46635		4 years	Mar- 11
LP Feed Water Heater Safeties		PM-OUTAGE H-1 FOUR YEAR PM OF L.P. HEATER SAFETY VALVES		Mar- 11
# 1 F.W. Heater Water Side	Size ¾", TYPE 19110MC-MT-FT-LA, Set 400, Shop # TM-37006, Capacity 59 GPM.		4 years	Mar- 11
# 2 F.W. Heater Steam Side	Size 2J3, Style J025-STM-C, Set 125, Shop # 35442, Capacity 9792		4 years	Mar- 11
# 2 F.W. Heater Water Side	Size ¾", Type 19110MC-MT-FT-LA, Set 400, B/M #41437A-2, Capacity 59 GPM, Serial # TM-37013		4 years	Mar- 11
# 3 F.W. Heater Steam Side	Size 2J3, Style J025-STM-C, Set 75, Shop # 35442		4 years	Mar- 11
# 3 F.W. Heater Water Side	Size ¾", TYPE 19110MC-MT-FT-LA, Set 400, Shop # TM-37012; B/M #41437A-3, Capacity 59 GPM		4 years	Mar- 11
Deaerating Heater safety valves 2 Ea.	Size 6" x 8", Style J0253-STM, Set 200, Shop # 47159-M2, Capacity 129,613		4 years	Mar- 11
HP Feed Water Heater Safeties		PM-OUTAGE H-1 FOUR YEAR PM OF H.P. HEATER SAFETY VALVES		Mar- 11
# 5 F.W. Heater Steam Side	Size 2H3, Style J036-STM-C, Set 350, Shop # 35539, Capacity 15697		4 years	Mar- 11
# 5 F.W. Heater Water Side	Size ¾" x 1", Style 995H/HPC1, Set 3000, S/N TK43795; B/M CC2079 Capacity 5518		4 years	Mar- 11
# 6 F.W. Heater Steam Side	Size 2.5" X 4", Model 1912JT-TD-34, Type 1912-00JT-4-CC-TD-34-RF-SS-HP, Set 725, S/N TJ95837, Capacity 53,501		4 years	Mar- 11
# 6 F.W. Heater Water Side	Size ¾", Type 1995T/HP-1, Set 3000, Shop # 37210, Capacity 5,521		4 years	Mar- 11

Frequency and Dates of Last Inspections
From the Big Rivers Boiler Condition Spreadsheet provided in AG 1-140

Equipment (Section)	Tube Size/Material	PM/Work Order Description	Frequency	Date of Last Inspection
Boiler (general)		PM-H-2 OUTAGE OBTAIN A TUBE SAMPLE FROM THE FOLLOWING AREAS	2 years	Feb-12
Economizer	2.5" O.D. x .250 MW SA-210 A1		2 years	Feb-12
Inlet Header	10.75" O.D. x 1.125" Av. Wall / SA-106- Gr. C			Apr-10
Outlet Header	10.75" O.D. x 1.125" Av. Wall / SA-106- Gr. C			Apr-10
Drum		PM-H-2 OUTAGE 18 MO DRUM INSPECT FOR BLR PERMIT RENEWAL	2 years	Apr-10
Furnace Water walls				
Sidewalls Front wall Rear Wall	2.5" O.D. x .203 MW / SA-178 Gr. C	Water wall mapping and (NDE)	2 years	Apr-10
		Boiler Chemical Clean		Oct-08
Knee Tubes	2.5" O.D. x .203 MW / SA-178 Gr. C	na	na	Feb-12
Rear WW deflection tubes	3.0" O.D. x .240 MW / SA-178 Gr. C	PM-H-2 OUTAGE OBTAIN TIGHT WIRE OF RWW DEFLECTION TUBES	2 years	Apr-10
Water wall Headers				
Drum Safeties	8.625" O.D. x 1.250" Thk. / SA-106 Gr. C			
Lower Furnace Side WW Header	8.625" O.D. x 1.250" Thk. / SA-106 Gr. C	PM-OUTAGE H-2 INSPECT THE LOWER WATER WALL HEADER	2 years	Apr-10
Front WW Releaser Header	8.625" O.D. x 1.250" Thk. / SA-106 Gr. C	PM-H-2 DYE CHECK SOUTH WATER WALL HEADER TUBES		Apr-10
Roof Release Header	8.625" O.D. x 1.250" Thk. / SA-106 Gr. C			
Furnace Rear WW Releaser Header	10.750" O.D. x 1.3750" Thk. / SA-106 Gr. C			
Convection Rear WW Release Header	8.625" O.D. x 1.250" Thk. / SA-106 Gr. C			
Down comers	16" O.D. x 1.218" Thk. / SA-106 Gr. C			
Furnace Rear Hopper Header	18.5" O.D. x 2.375" Thk. / SA-106 Gr. C			
Furnace Side Hopper Header	16" O.D. x 2.000" Thk. / SA-106 Gr. C			
Primary Superheater			2 years	Feb-12
Upleg Assemblies	2.5" O.D. x .203 MW / SA 178 Gr. C			
Inlet Header	10.75" O.D. x 1.375" Thk. / SA-106- Gr. C			
Outlet Header	14" O.D. x 1.375" Thk. / SA-335 P11			
Radiant Superheater (High Temp. Superheater)		PM-H-2 OUTAGE INSPECTION OF RADIANT SUPERHEATER	2 years	Feb-12
				Apr-10
Main Steam Inlet Header	16" O.D. x 1.375" Thk. / SA-335 P11			
Main Steam Outlet Header	16" O.D. x 2.5" Thk. / SA-335 P22	H-2 Boiler Header Condition Assessment - High Temp Reheat, Superheat outlet, Economizer Inlet, and the Economizer outlet headers.	4 years - This is based on the Riley report from 2009	Apr-10
East Superheat Spray Attemperator		PM-OUTAGE - INSPECT H-2 EAST SUPERHEAT SPRAY ATTEMPERATOR	6 year	Apr-10
West Superheat Spray Attemperator		PM-OUTAGE - INSPECT H-2 WEST SUPERHEAT SPRAY ATTEMPERATOR	6 years	Apr-10
High Temperature Reheater Inlet Bank (Primary Reheater)	2.5" O.D. x .135 MW / SA-178 Gr. A	PM-H-2 OUTAGE INSPECTION OF HIGH TEMP REHEATER	2 years	Feb-12
High Temperature Reheater Intermediate Bank	2" O.D. x .120 MW / SA 213 T11		2 years	Apr-10
High Temperature Reheater Outlet Bank	2" O.D. x .148 MW / SA 213 T22	PM-OUTAGE - H-2 PRIMARY REHEATER	2 years	Apr-10
Reheat Inlet Header	16" O.D. x .656 Avg. Thk. / SA-106 Gr. B			Oct-08
Reheat Outlet Header	22" O.D. x 1.250' Thk. / SA-335 P22	H-2 Boiler Header Condition Assessment - High Temp Reheat, Superheat outlet, Economizer Inlet, and the Economizer outlet headers.		Apr-10
East Reheat Spray Attemperator			6 year	
West Reheat Spray Attemperator			6 years	
High Energy Pipe Hangers				
Hot Reheat Pipe Hangers				Feb-12
Cold Reheat Pipe Hangers				Feb-12
Main Steam Pipe Hangers				Feb-12

Equipment (Section)	Tube Size/Material	PM/Work Order Description	Frequency	Date of Last Inspection
Safety Valves				
Boiler Safeties		PM-H-2 OUTAGE INSPECTION OF BOILER SAFETY VALVES	4 years	Feb-12
North East Drum Safety	Size 3", Style 1759WA-2-S, Set 2200, Shop # BN63474, Capacity 383,700 #/hr		4 years	Feb-12
South East Drum Safety	Size 3", Style 1759WA-2-S, Set @ 2230, Shop # BN6348, Capacity 348,400 #/hr		4 years	Feb-12
West Drum Safety	Size 3", Style 1749WA-1-S, Set @ 2260, Shop #BN6141, Capacity 420,500 #/hr;		4 years	Feb-12
Superheat Steam Line Safety	Size 2-1/2", Style 1738WD-1-S, Set 2040, Shop # BN6350, Capacity 201,856 #/hr		4 years	Feb-12
Reheater Safety Valve #1	Size 4", Style 1755QWD-1-S, Set 535, Shop # BN6146, Capacity 214,510 #/hr		4 years	Feb-12
Reheater Safety Valve # 2	Size 4", Style 1775QWB-1-S, Set 580, Shop # BN6352, Capacity 265,698 #/hr		4 years	Feb-12
Reheater Safety Valve #3	Size 4", Style 1775QWB-1-S, Set 595, Shop # BN6143, Capacity 272,353 #/hr		4 years	Feb-12
Reheater Safety Valve #4	Size 6", Style 1705RWB-1-S, Set 610 Shop # BN6145, Capacity 404,115 #/hr		4 years	Feb-12
Soot blower system safety	Size 2" x 3", Style 1922HT, Set 600, Shop # TC 81364, Capacity 26,480		4 years	Feb-12
Low Pressure Header System Safety	Size 4"x 6", Style J0263STMC, Set 125, Shop # 45627 M2, Capacity 33027		4 years	Feb-12
LP Feed Water Heater Safeties		PM-H-2 OUTAGE FIVE YEAR PM OF L.P. HEATER SAFETY VALVES		Feb-12
# 1 F.W. Heater Water Side	Size ¾" x 1", Style JMB-C-C, Set 400, Shop # 34970, Capacity N/A		4 years	Feb-12
# 2 F.W. Heater Steam Side	Size 2J3, Style J025-STM-C, Set 50, Shop # 35442M3, Capacity 4484		4 years	Feb-12
# 2 F.W. Heater Water Side	Size ¾" x 1", Style 1994C, Set 400, Shop # TH 56384, Capacity 200		4 years	Feb-12
# 3 F.W. Heater Steam Side	Size 2J3, Style J025-STM-C, Set 75, Shop # 35442, Capacity 6253		4 years	Feb-12
# 3 F.W. Heater Water Side	Size ¾" x 1", Style 1994C, Set 400, Shop # TH 56379, Capacity 325		4 years	Feb-12
Deaerating Heater safety valves 2 Ea.	Size 6" x 8", Style J025-3-STM, Set 200, Shop # 47159-M2, Capacity 99,240		4 years	Feb-12
HP Feed Water Heater Safeties		PM-H-2 OUTAGE FIVE YEAR PM OF H.P. HEATER SAFETY VALVES		Feb-12
# 5 F.W. Heater Steam Side	Size 2-1/2" J-4, Style J046-STM-C, Set 300, Shop # 35539M5, Capacity 13537		4 years	Feb-12
# 5 F.W. Heater Water Side	Size ¾" x 1", Style JMB-T-C, Set 3000, Shop # 40831, Capacity 5681		4 years	Feb-12
# 6 F.W. Heater Steam Side	Size 2-1/2, Style 1912 JC-2, Set 650, Shop # TH 72856		4 years	Feb-12

Frequency and Dates of Last Inspections
From the Big Rivers Boiler Condition Spreadsheet provided in AG 1-140

Equipment (Section)	Tube Size/Material	PM/Work Order Description	Frequency	Date of Last Inspection
Boiler (general)		PM-OUTAGE R-1 OBTAIN A TUBE SAMPLE		Sep-08
Economizer	2.0" O.D. x .150 MW SA-178 Gr. C		2 years	Sep-08
Upleg Assemblies	2.52" O.D. x .180 MW / SA 178 Gr. C			
Inlet Header	12.75" O.D. x 1.125" Av. Wall / SA-106- Gr. B			
Outlet Header	8.625" O.D. x 1.100" Min. Wall / SA-106- Gr. C			
Drum		PM-OUTAGE R-1 18 MO DRUM INSPECT FOR BLR PERMIT RENEWAL	2 years	Sep-08
Furnace Waterwalls				
Sidewalls Front Wall Rear Wall	3.250" O.D. x .220 MW / SA-178 Gr. C	Waterwall mapping and (NDE)	2 years	
		Boiler Chemical Clean	10 years	Jun-04
Knee Tubes	3.250" O.D. x .220 MW / SA-178 Gr. C			
Upper Furnace Arch	3.250" O.D. x .220 MW / SA-178 Gr. C			
Drum Safeties		na	na	
Lower Side WW Header	18.5" O.D. x 1.5 Min. Thk. / SA-106 Gr. C	REPLACE R-1 LOWER WATERWALL HEADER TUBE STUBS	na	Sep-08
Lower Side Sloping Headers	10.750" O.D. x 1.125 Ave. Thk. / SA-106 Gr. B			
Front Hopper Header	18.5" O.D. x 1.5 Min. Thk. / SA-106 Gr. C			
Platten Headers	16" O.D. x 1" Min. Thk. / SA-106 Gr. C	Visual Inspection	2 years	Jun-04
Rear Hopper Header	21.5" O.D. x 1.40" Min. Thk. / SA-106 Gr. C			
Downcomer to Hopper Header Upper Section	21.5" O.D. x 1" Min. Thk. / SA-106 Gr. C			
Lower Section Downcomer to Hopper Header	21.5" O.D. x 1" Min. Thk. / SA-106 Gr. C			
Downcomer Pipe to Platen Header	16" O.D. x 1.031" Ave. Thk. / SA-106 Gr. B			
Primary Superheater			2 years	Sep-08
Downleg Assemblies Points A to B&C Points B&C to D	2.5" O.D. x .165 MW / SA 210 2.5" O.D. x .180 MW / SA 210			
Inlet Header	8.625" O.D. x 1.100" Thk. / SA-106- Gr. C			
Outlet Header	14" O.D. x 1.150" Thk. / SA-335 P11			
High Temp Superheater	Outlet tubes - 2.5" O.D. x .260 MW SA 213 T22	PM-OUTAGE R-1 INSPECTION OF RADIANT SUPERHEATER	2 years	Sep-08
	Inlet tubes - 2.5" O.D. x .165 MW SA 213 T11			
Main Steam Inlet Header	12.750" O.D. x 1.150" Thk. / SA-106- Gr. C			
Main Steam Outlet Header	14" O.D. x 1.375/1.150" Thk. / SA-335 P11			
Boiler Safeties		PM-OUTAGE R-1 INSPECTION OF BOILER SAFETY VALVES	4 years	June - 08
North West Drum Safety	Size 3", 1500 PSI @ 675 DEG POP @ 1515, CLOSE @ 1454, RELIEVE 282,746, ORFICE 3.976", DWG #G-36967-48: 6" OUTLET, Crosby Model: HC85W		4 years	June - 08
South West Drum Safety	Size 2 1/2"; 1500PSI @ 675 DEG, POP@1475, CLOSE @1416, RELIEVE 176,249, ORFICE 2.545" DWG#G-36967-48: 6" OUTLET. Crosby Model: HC65W		4 years	June - 08
East Drum Safety	Size 2 1/2", 1500PSI @ 675 DEGREES, POP@1495, CLOSE @ 1435, RELIEVE 178,616 ORFICE 2.545", DWG #G3698748: 6" OUTLET, Crosby Model: HC65W		4 years	June - 08
Superheat Steam Line Safety	Size 2 1/2", 1060 F; POP @1375, CLOSE @ 1320, RELIEVE @ 129,887, ORFICE 2.545":6", OUTLET; DWG#G3696887: Crosby Model HCA58		4 years	June - 08
Sootblower system safety	Consolidated - SIZE 2 X 3; SET @ 600 PSIG; CAP. 27,115#, STYLE 1912HTC-1-34; B/M CC2079-S14960; INDUS. VALVE-MOBILE, ALABAMA IVS#S14960, Model: 1912H		4 years	June - 08
Electromatic Relief Valve				

Equipment (Section)	Tube Size/Material	PM/Work Order Description	Frequency	Date of Last Inspection
LP Feed Water Heater Safeties		PM-OUTAGE R-1 FOUR YEAR PM OF L.P. HEATER SAFETY VALVES		
# 3 F.W. Heater Steam Side	TYPE 1511K-XIP; S/N BY72484; SET @ 50 PSIG; CAPACITY 550 LBS/HR; SIZE 4"; DALCO INC. #40695-		4 years	June - 08
# 3 F.W. Heater Water Side	TYPE 1982C-XLS; S/N TM29920; SET @ 275 PSIG; CAPACITY 108.2 CPM WATER; SIZE 3/4"; DALCO INC. #40695-8		4 years	June - 08
# 4 F.W. Heater Steam Side	TYPE 1511K-XIP; SET @ 50 PSIG; CAPACITY 550 LBS/HR; S/N BY72486; SIZE 2"; DALCO INC. #40695-4; INSTALLED NEW 11/2000		4 years	June - 08
# 4 F.W. Heater Water Side	Farris Engineering - SIZE 3/4" X 1"; TYPE #1870;SET PRESSURE 275#; SPRING CSCP; TAG # S-11-K ; Model: 1870		4 years	June - 08
Deaerating Heater safety valves 2 Ea.	Farris Engineering - Size 4 N 6; STYLE 1960-OL; SET @ 100 PSIG; CAPACITY 30,780 #/HR; SHOP # (NOT LISTED) TAG # S-11-8, Model: 1960		4 years	June - 08
HP Feed Water Heater Safeties		PM-OUTAGE R-1 FOUR YEAR PM OF H.P. HEATER SAFETY VALVES		
# 1 F.W. Heater Steam Side	TYPE 1811JB-6X; S/N BY72824; SET @ 450 PIG; CAPACITYN27786 #/HR; SIXE 1-1/2"; LIFT .321"; DALCO INC. #40695-1;		4 years	June - 08
# 1 F.W. Heater Water Side	TYPE 19096MC-LA-MT-FT; S/N TM29851; SET @ 2000 PSIG; CAPACITY 115CPM WATER; SIZE 3/4"; DALCO INC. #40695-7;		4 years	June - 08
# 2 F.W. Heater Steam Side	TYPE 1811HB-3X; S/N BY77106; SET @ 250; CAPACITY 9647 LBS/HR; SIZE 1-1/2"; LIFT .250"; DALCO INC. #40695-2;		4 years	June - 08
# 2 F.W. Heater Water Side	TYPE 19096MC-LA-MT-FT; S/N TM 29847; SET @ 2000 PSIG; CAPACITY 115 CPM WATER; SIZE 3/4'; DALCO INC. #40695-6;		4 years	June - 08

Frequency and Dates of Last Inspections
From the Big Rivers Boiler Condition Spreadsheet provided in AG 1-140

Equipment (Section)	Tube Size/Material	PM Description	Frequency	Date of Last Inspection
Boiler (general)		Acquisition of tube samples; waterwalls, platen superheats, and finishing superheats	2 years	Nov-09
		Chemical Cleaning	12 years	Nov-09
Economizer		Economizer Section, inspection and repair	2 years	Nov-09
		na	na	na
Inlet Header	14.75" ID SA106C			Nov-09
Element	2.25" OD x .224 MW SA178C			
Element	2" OD x .200 MW SA178C			
Element	2" OD x .250 MW SA178C			
Element	2" OD x .212 MW SA213-T2			
Unheated Outlet Stubs	2.25" OD x .224 MW SA178C			
Drum Safeties	10.5" ID SA106C			
Drum		Drum, inspection and repair	2 years	Nov-09
Downcommers	24" OD x Sch 160 SA106C			
Waterwalls		Waterwall mapping and (NDE)	2 years	Nov-09
		na	na	
Feeders	6" Sch #160 SA106C			
Risers Front	6" Sch #160 SA106B			
Risers Side	6" Sch #160 SA106B			
Risers Rear	6" Sch #160 SA106B			
FW Lower	3" OD x .318 MW SA210C			
FW Rifled	3" OD x .368 MW SA210C			
FW Upper	3" OD x .280 MW SA210C			
RW Lower	3" OD x .318 MW SA210C			
RW Rifled	3" OD x .368 MW SA210C			
RW Upper	3" OD x .280 MW SA210C			
RW Support	3.5" OD x .405 MW SA210C			
SW Lower	3" OD x .318 MW SA210C			
SW Rifled	3" OD x .368 MW SA210C			
SW Upper	3" OD x .280 MW SA210C			
Steam Supply to roof	6" Sch #160 SA106B			
Roof	*2.25" OD x .220 MW SA213T11*			
HRA RW Upper	1.75" OD x .190 MW SA213T2			
HRA RW Lower	1.75" OD x .187 MW SA178C			
Partition Wall Feeder	6" Sch #160 SA106C			
Partition Wall Screen	2" OD x .217 MW SA213T2			
Partition Wall Support	2.375" OD x .382 MW SA213T2			
Partition Wall Lower	2" OD x .250 MW SA178C			
Partition Wall Riser	6" Sch #160 SA106C			
HRA SW Upper	1.75" OD x .190 MW SA213T2			
HRA SW Lower	1.75" OD x .187 MW SA178C			
HRA SW Transfer Upper	6" Sch #160 SA106C			
HRA SW Transfer Lower	6" Sch #160 SA106C			
HRA SW Vestibule Feed	6" Sch #160 SA106C			
HRA SW Vestibule	2" OD x .286 MW SA213T2			
HRA SW Vestibule Corner	2.375" OD x .440 MW SA213T2			
HRA SW Vestibule Riser	6" Sch #160 SA106C			
HRA FW Support	2.25" OD x .372 MW SA213T2			
HRA FW Feeder	6" Sch #160 SA106C			
HRA Front Upper Screen	2" OD x .286 MW SA213T2			
HRA FW Lower	2" OD x .250 MW SA178C			
HRA FW Riser	6" Sch #160 SA106C			

Frequency and Dates of Last Inspections
From the Big Rivers Boiler Condition Spreadsheet provided in AG 1-140

Equipment (Section)	Tube Size/Material	PM Description	Frequency	Date of Last Inspection
Primary Superheat		Superheat sections, inspection and repair	2 years	Nov-09
Inlet	2" OD x .214 MW SA210A1			
	2.25" OD x .369 MW SA210A1			
	2.25" OD x .250 MW SA213T11			
	2" OD x .211 MW SA213T2			
"A" Platen Superheater		Superheat sections, inspection and repair	2 years	Nov-09
"B" Platen Superheater		Superheat sections, inspection and repair	2 years	Nov-09
Inlet Header	18.75" OD x 2.125 MW SA106C	Take MT readings, and replications on attachment welds	2 Years	Nov-09
Attemperator 1st Stage	20" OD		6yrs	Nov-09
Attemperator 1st Stage	20" OD		6yrs	Nov-09
Inlet Bottles	8.625" OD x 1.5 AW SA106C			
Outlet Header	8.625" OD x 1.625 AW SA106C	Take MT readings, and replications on attachment welds	2 years	Nov-09
Inlet Elements	1.75" OD x .260 MW SA213T11			Nov-09
Outlet Elements	1.75" OD x .300 MW SA213T22			Nov-09
Lead Elements	1.75" OD x .238 MW SA213TP304H			
Risers	4" OD x .429 MW SA213T2			
Finish Superheat		Superheat sections, inspection and repair	2 years	Nov-09
		na	na	na
Inlet Header	20" OD x 2.375 MW SA335P11			
Attemperator 2nd Stage	20" OD	Boroscopic examination of header, nozzle removed and inspected	6 years	Nov-09
Attemperator 2nd Stage	20" OD	Boroscopic examination of header, nozzle removed and inspected	6 years	Nov-09
Outlet Header	31.5 OD x 5.375 MW SA335P22			Nov-09
Leg 1 Elements	2.25" OD x .230 MW SA213T11			
	2.25" OD x .282 MW SA213TP304H			
	2.25" OD x .413 MW SA213T22			
	2.25" OD x .363 MW SA213T22			
Leg 2 Elements	2.25" OD x .482 MW SA213T22			
Leg 3 Elements	2" OD x .253 MW SA213TP304H			
Leg 4 Elements	2" OD x .293 MW SA213TP304H			
	2" OD x .225 MW SA213TP304H			
Reheater		Reheat Section, inspection and repair	2 Years	Nov-09
		na	na	na
Inlet Header	30" ID SA335-P2			
Inlet vertical legs	2.5" OD x .180 MW SA178A			
Unheated outlet tubes	2.25" OD x .180 MW SA213-T22			
Outlet Header	34" ID SA335P-22			
Attemperator Spray (Left)				
Attemperator Spray (Right)				
Horizontal legs 1-9	2.5" OD x .180 MW SA178A			
Horizontal legs 10-13	2.5" OD x .180 MW SA213T2			
Horizontal legs 14-15	2.25" OD x .180 MW SA213T11			
Horizontal legs 16-17	2.25" OD x .200 MW SA213T22			
Horizontal leg 18	2" OD x .150 MW SA213TP304			
Headers		na	na	Nov-09
Boiler Feed Pump Suction and Discharge Piping		Perform Guided Long Wave Testing on this piping to determine thinning and Flow Assisted Corrosion	6 Years	Nov-09
DA Storage Tank		Perform MT inspection on all circumferential welds, longitudinal welds, nozzles, exterior leg supports, and interior attachment welds. Perform UT Measurements on the heads, shell, and downcomers.	2 years	Nov-09
DA Heater		Perform MT inspection on all circumferential welds, longitudinal welds, nozzles, exterior leg supports, and interior attachment welds. UT Measurements should be taken, and anything under .400" should be marked up for weld repairs.	2 years	Nov-09

Equipment (Section)	Tube Size/Material	PM Description	Frequency	Date of Last Inspection
HIGH ENERGY PIPING				
MAIN STEAM PIPING TO TURBINE	23.25" OD x 3.442 MW SA335P22	MT Connections and Nozzles, Replications on Circ. Welds, MT Circ Welds, MT Hanger Attachments, UT Circ. Welds. A Section of the piping will be inspected each outage. Each section is about 1/3 of the total Main Steam Piping. Thus, a complete inspection of the entire main steam piping system will be performed every six years.	6 years	Nov-09
	19" OD x 2.817 MW SA335P22			
HOT REHEAT PIPING TO TURBINE	32.5" OD x 1.375 SA691Gr2¼Cr	MT Connections and Nozzles, Replications on Circ. Welds, MT Circ Welds, MT Hanger Attachments, UT Circ. Welds, MT and UT Longitudinal Welds. A Section of the piping will be inspected each outage. Each section is about 1/3 of the total Hot Reheat Piping. Thus, a complete inspection of the entire hot reheat piping system will be performed every six years.	6 Years	Nov-09
	32.5" OD x 1.375 SA691Gr2¼Cr			
COLD REHEAT PIPING FROM TURBINE	33" OD x .75 MW SA155GrKC65	MT Connections and Nozzles. MT Pipe Hanger Attachment Welds, UT Circumferential Welds. Replications on Circ. Welds.	6 Years	Nov-09
	24" OD x Sch 40 MW SA155GrKC65			
CRITICAL PIPE HANGERS				
Main Steam Hangers				
MSH-1			2 years	Nov-09
MSH-1			2 years	Nov-09
MSH-2			2 years	Nov-09
MSH-3			2 years	Nov-09
MSH-4			2 years	Nov-09
MSH-4			2 years	Nov-09
MSH-5			2 years	Nov-09
MSH-6			2 years	Nov-09
MSH-7			2 years	Nov-09
MSH-7			2 years	Nov-09
MSH-8			2 years	Nov-09
MSH-8			2 years	Nov-09
MSH-9			2 years	Nov-09
MSH-10			2 years	Nov-09
MSH-11			2 years	Nov-09
MSH-11			2 years	Nov-09
MSH-12			2 years	Nov-09
MSH-13			2 years	Nov-09
MSH-14			2 years	Nov-09
MSH-15			2 years	Nov-09
MSH-16			2 years	Nov-09
MSH-17			2 years	Nov-09
MSH-18			2 years	Nov-09
MSH-19			2 years	Nov-09
MSH-20			2 years	Nov-09

Frequency and Dates of Last Inspections
From the Big Rivers Boiler Condition Spreadsheet provided in AG 1-140

Equipment (Section)	Tube Size/Material	PM Description	Frequency	Date of Last Inspection
Cold Reheat Hangers				
CRH-1			2 years	Nov-09
CRH-1			2 years	Nov-09
CRH-2			2 years	Nov-09
CRH-3			2 years	Nov-09
CRH-4			2 years	Nov-09
CRH-5			2 years	Nov-09
CRH-6			2 years	Nov-09
CRH-6			2 years	Nov-09
CRH-7			2 years	Nov-09
CRH-8			2 years	Nov-09
CRH-9			2 years	Nov-09
CRH-10			2 years	Nov-09
CRH-11			2 years	Nov-09
CRH-12			2 years	Nov-09
CRH-13			2 years	Nov-09
CRH-14			2 years	Nov-09
CRH-14			2 years	Nov-09
CRH-15			2 years	Nov-09
CRH-16			2 years	Nov-09
CRH-17			2 years	Nov-09
CRH-18			2 years	Nov-09
CRH-19			2 years	Nov-09
CRH-19			2 years	Nov-09
CRH-20			2 years	Nov-09
CRH-21			2 years	Nov-09
CRH-22			2 years	Nov-09
CRH-23			2 years	Nov-09
CRH-23			2 years	Nov-09
CRH-24			2 years	Nov-09
CRH-25			2 years	Nov-09
CRH-26			2 years	Nov-09
CRH-27			2 years	Nov-09
CRH-28			2 years	Nov-09
CRH-28			2 years	Nov-09
CRH-28			2 years	Nov-09
CRH-29			2 years	Nov-09

Equipment (Section)	Tube Size/Material	PM Description	Frequency	Date of Last Inspection
Hot Reheat Hangers				
HRH-1			2 years	Nov-09
HRH-2			2 years	Nov-09
HRH-3			2 years	Nov-09
HRH-4			2 years	Nov-09
HRH-4			2 years	Nov-09
HRH-5			2 years	Nov-09
HRH-6			2 years	Nov-09
HRH-7			2 years	Nov-09
HRH-7			2 years	Nov-09
HRH-8			2 years	Nov-09
HRH-8			2 years	Nov-09
HRH-9			2 years	Nov-09
HRH-10			2 years	Nov-09
HRH-11			2 years	Nov-09
HRH-11			2 years	Nov-09
HRH-12			2 years	Nov-09
HRH-13			2 years	Nov-09
HRH-14			2 years	Nov-09
HRH-15			2 years	Nov-09
HRH-16			2 years	Nov-09
HRH-17			2 years	Nov-09
HRH-17			2 years	Nov-09
HRH-18			2 years	Nov-09
HRH-18			2 years	Nov-09

SAFETY VALVES

Boiler Drum Safety Valves				
RV-1 Safety Valve	Crosby, size 3M6, style HE-96W, dwg# DSC-58456-19 Rev.A	Boiler, Safety Valves, Inspect & Repair	2 Years	Nov-09
RV-2 Safety Valve	Crosby, size 3M6, style HE-96W, dwg# DSC-58456-19 Rev.A	Boiler, Safety Valves, Inspect & Repair	2 Years	Nov-09
RV-3 Safety Valve	Crosby, size 3M6, style HE-96W, dwg# DSC-58456-19 Rev.A	Boiler, Safety Valves, Inspect & Repair	2 years	Nov-09
RV-4 Safety Valve	Crosby, size 3M6, style HE-96W, dwg# DSC-58456-19 Rev.A	Boiler, Safety Valves, Inspect & Repair	2 Years	Nov-09
RV-5 Safety Valve	Crosby, size 3M6, style HE-96W, dwg# DSC-58456-19 Rev.A	Boiler, Safety Valves, Inspect & Repair	2 Years	Nov-09
Superheat Steam Safety Valves				
RV-9 Safety Valve	Crosby, size 3M6, style HCA-98W, dwg# DS-C-56551-18 Rev.O	Boiler, Safety Valves, Inspect & Repair	2 Years	Nov-09
RV-10 Safety Valve	Crosby, size 3M6, style HCA-98W, dwg# DS-C-56551-18 Rev.O	Boiler, Safety Valves, Inspect & Repair	2 Years	Nov-09
Hot Reheat Safety Valves				
RV-21 Safety Valve	Crosby style 4Q8, style HCA-38W, dwg# DS-C-61135-10 Rev. A	Boiler, Safety Valves, Inspect & Repair	2 Years	Nov-09
RV-22 Safety Valve	Crosby style 4Q8, style HCA-38W, dwg# DS-C-61135-10 Rev. A	Boiler, Safety Valves, Inspect & Repair	2 Years	Nov-09
Cold Reheat Safety Valves				
RV-15 Safety Valve	Crosby style 4Q8, style HC-36W, dwg# DS-C-60778-7 Rev. A	Boiler, Safety Valves, Inspect & Repair	2 years	Nov-09
RV-16 Safety Valve	Crosby style 4Q8, style HC-36W, dwg# DS-C-60778-7 Rev. A	Boiler, Safety Valves, Inspect & Repair	2 years	Nov-09
RV-17 Safety Valve	Crosby style 6R8, style HC-36W, dwg# DS-C-60779-17 Rev. A	Boiler, Safety Valves, Inspect & Repair	2 years	Nov-09
RV-18 Safety Valve	Crosby style 6R8, style HC-36W, dwg# DS-C-60779-17 Rev. A	Boiler, Safety Valves, Inspect & Repair	2 years	Nov-09
RV-19 Safety Valve	Crosby style 6R8, style HC-36W, dwg# DS-C-60779-17 Rev. A	Boiler, Safety Valves, Inspect & Repair	2 years	Nov-09
RV-20 Safety Valve	Crosby style 6R8, style HC-36W, dwg# DS-C-60779-17 Rev. A	Boiler, Safety Valves, Inspect & Repair	2 years	Nov-09

Frequency and Dates of Last Inspections
From the Big Rivers Boiler Condition Spreadsheet provided in AG 1-140

Equipment (Section)	Tube Size/Material	PM Description	Frequency	Date of Last Inspection
Auxiliary Steam Safety Valves				
RV-24 (1) Safety Valve	Consolidated 6", 600# Std. RF; Style - 1912-QT-TD-34; LG8834; Dwg. # 619-26-002 Serial # TG-30723	Boiler, Safety Valves, Inspect & Repair	2 Years	Nov-09
RV-24 (2) Safety Valve	Consolidated 6", 600# Std. RF; Style - 1912-QT-2-TD-34-MS-RF LG8834; Dwg. # 619-26-002 Serial # TG-30724	Boiler, Safety Valves, Inspect & Repair	2 Years	Nov-09
RV-25 (1) Safety Valve	Consolidated 6", 300# Std. RF; Style - 1912-30R/P2-1 LG8834; Dwg. # 619-26-003 Serial #: TP-38600	Boiler, Safety Valves, Inspect & Repair	2 Years	Nov-09
RV-25 (2) Safety Valve	Consolidated 6", 300# Std. RF; Style - 1912-30R/P2-1 LG8834; Dwg. # 619-26-003 Serial #: TL-21965	Boiler, Safety Valves, Inspect & Repair	2 Years	Nov-09
RV-26 Safety Valve	Consolidated 8", 300# Std. RF; Style - 1912-30T/P2-1 LG9034; Dwg. # 619-26-004 Serial #: TG-30725	Boiler, Safety Valves, Inspect & Repair	2 Years	Nov-09
Steam Coil Condensate Drain Tank Safety Valves				
RV-37 (1) Safety Valve	Consolidated 2", 150# Std. RF; Style - 1905 JC-CC-TD-34; Dwg. # 619-26-006 Serial #: TP40963	Boiler, Safety Valves, Inspect & Repair	2 Years	Nov-09
RV-37 (2) Safety Valve	Consolidated 2", 150# Std. RF; Style - 1905 Jt P1-1; Dwg. # 619-26-006 Serial #: TG30739	Boiler, Safety Valves, Inspect & Repair	2 Years	Nov-09
Sootblower Safety Valves				
Sootblower Safety Valve 1	Consolidated 2", 485 Set Pressure, Serial # TN22671, Type 1910-00HT-T-CC-TD-34	Boiler, Safety Valves, Inspect & Repair	4 years	Mar-08
Sootblower Safety Valve 2	Consolidated 4", 600 # Class Model #: 1912LT-TD Serial # TE94443	Boiler, Safety Valves, Inspect & Repair	2 years	Nov-09
Sootblower Safety Valve 3	Consolidated 4", 900 # Class Model #: 1924LT-1-TD Serial # TE94444	Boiler, Safety Valves, Inspect & Repair	2 years	Nov-09
Sootblower Safety Valve 4	Consolidated 4", 600 # Class Model #: 1912-LT-1 Serial # TE94442	Boiler, Safety Valves, Inspect & Repair	2 years	Nov-09
Feedwater Heater Safety Valves				
Heater #2 Safety Valve	Consolidated 6", 150# Class Dwg. # 605-00-010 Model #: 1905QC-1 Serial # TE70740	Boiler, Safety Valves, Inspect & Repair	2 Years	Nov-09
Heater #3 Safety Valve	Consolidated 6", 150# Class Dwg. # 605-00-010 Model #: 1905QC-1 Serial # TE70866	Boiler, Safety Valves, Inspect & Repair	2 Years	Nov-09
Heater #4 Safety Valve	Consolidated 6", 150# Class Dwg. # 605-00-010 Model #: 1905QT-1 Serial # TE70868	Boiler, Safety Valves, Inspect & Repair	2 Years	Nov-09
Heater #5 Safety Valve	Consolidated 2 1/2" 300# Class Dwg. # 1811 LA20 Model #: 1811LA-20 Serial # BV08890	Boiler, Safety Valves, Inspect & Repair	2 Years	Nov-09
Heater #6 Safety Valve	Consolidated 4", 300 # Class Dwg. # 605-00-011 Model #: 1910NC-1 Serial # TE70730	Boiler, Safety Valves, Inspect & Repair	2 Years	Nov-09
Heater #7 Safety Valve	Consolidated 4", 600 # Class Dwg. # 605-00-012 Model #: 1912LT-1 Serial # TE70734	Boiler, Safety Valves, Inspect & Repair	2 Years	Nov-09

Exhibit Holloway-3

RUS Communications on Creep Testing

Ralph Ashworth

From: Billie Richert
Sent: Tuesday, December 11, 2012 3:39 PM
To: James J. Murray (james.murray@wdc.usda.gov) (james.murray@wdc.usda.gov)
Cc: Ralph Ashworth
Subject: Follow-up to your two questions re: Depreciation Study
Attachments: Creep Testing All Units Next Schedule.xlsx

Jim,
To follow-up on your two questions related to our depreciation study:

1) All of the major maintenance that has been deferred is scheduled to be completed by the end of 2015.
2) Next creep testing scheduled by unit – see attached

Thanks,
Billie

Item 1 Completion of Creep Testing

The following table provides a summary of the most recent testing performed for each generation unit.

Plant	Last Test	Problems Found	Description	Action Taken
Coleman 1	May 2008	1	Hot reheat hanger attachment.	Addressed immediately through appropriate repairs.
Coleman 2	October 2010	0	No deficiencies found.	
Coleman 3	June 2009	1	Indication of early stage creep.	No operational limits, per EPRI guidelines. Retest in 3-5 years.
Green 1	November 2011	0	No deficiencies found.	
Green 2	May 2009	0	No deficiencies found.	
HMP&L 1	April 2012	0	No relevant indications.	
HMP&L 2	April 2010	0	No evidence of micro cracking or creep damage.	
Reid 1	June 2008	1	Operating stress well within limits.	Retest in 5-10 years.
Wilson 1	November 2009	0	No indications found.	

Exhibit Holloway-4

RUS Communications on Deferred Maintenance

Big Rivers
ELECTRIC CORPORATION

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

February 6, 2013

Mr. Chris Tuttle
Acting Deputy Assistant Administrator
Rural Utilities Service-Electric Program
United States Department of Agriculture
Room No. 5135-S
1400 Independence Avenue, S.W.
Stop 1510
Washington, D.C. 20250

Subject: Kentucky 62 - Big Rivers Electric Corporation

Dear Mr. Tuttle:

Please refer to your letter to me of December 27, 2012, approving the new depreciation rates proposed by Big Rivers Electric Corporation ("*Big Rivers*"). A copy of that letter is attached for your convenience. In that letter you conclude that certain Big Rivers' major maintenance and inspection practices, as described in the Executive Summary of the Burns & McDonnell Depreciation Study, are not acceptable to the Rural Utilities Service ("*RUS*"). You direct that Big Rivers "needs to resume their scheduled major inspections and maintenance per prudent utility operations promptly," and ask that Big Rivers inform you of its timeline for getting that matter resolved.

Big Rivers takes very seriously its obligations to its Members and the RUS to maintain its assets in accordance with prudent utility practice. The purposes of this letter are to furnish assurance that Big Rivers is properly inspecting and performing major maintenance on its assets, and to provide the maintenance schedule Big Rivers developed in May of 2012 to perform certain maintenance projects that had been deferred.

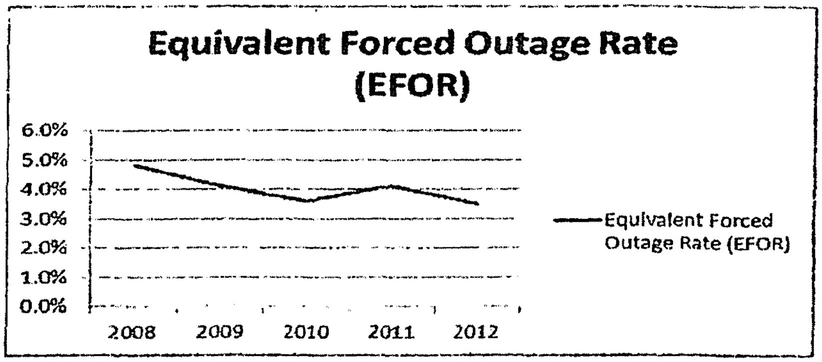
Big Rivers has selectively deferred certain inspection and maintenance activities since 2009 to assure that it will achieve its financial covenant performance requirements during a period of depressed wholesale power market prices and an unusually weak economy. But Big Rivers did not stop maintaining its assets. It selectively chose certain activities to complete, and others to defer, in order to continue to maintain a prudent level of maintenance while Big Rivers was adjusting to an economy in recession.

As a result of those efforts, Big Rivers' generating fleet has been very reliable since the closing of the Unwind Transaction in July 2009, and has consistently performed in the top quartile of its peer group in Equivalent Forced Outage Rate ("*EFOR*"), which we benchmark through Navigant's GKS system. The table below shows that Big Rivers' generating plant reliability has improved over the last five years, indicating the effectiveness of Big Rivers' maintenance program.

Big Rivers Generating Fleet	**2008**	**2009**	**2010**	**2011**	**2012**
Equivalent Forced Outage Rate (EFOR) *	4.8%	4.1%	3.6%	4.1%	3.5%

*EFOR (Lower is Better)

The following graph illustrates the downward trend (lower is better) in EFOR over the last five years.



Burns & McDonnell agrees with the prudency of Big Rivers' past maintenance practices and future maintenance plans in testimony filed with the Kentucky Public Service Commission on January 15, 2013, with Big Rivers' application for a general adjustment in rates. An excerpt of that testimony is attached for your information, and the full testimony is available under tab 71 of the copy of the application that Big Rivers sent to RUS on January 15, 2013.

The deferred maintenance schedule Big Rivers developed in May of 2012, and provided to Mr. James J. Murray by email dated December 12, 2012, affirms Big Rivers' intention to continue to perform major maintenance on its assets in a prudent and timely manner. That table is reproduced below, and remains unchanged from the version provided in December of 2012, and shows Big Rivers' timeline for performing the selected items of maintenance that were previously deferred. Big Rivers hopes this information allays RUS concerns. Please contact me if you have any further questions.

Deferred Maintenance Schedule		
The following table provides a summary of the deferred outages and when they will be completed.		
Plant	**Original Outage Schedule**	**Deferred Maintenance To Be Completed**
Coleman 1	February 2011	[redacted]
Coleman 2	March 2013	[redacted]
Coleman 3	May 2012	[redacted]
Green 1	March 2012	[redacted]
Green 2	March 2011	[redacted]
HMP&L 1	May 2011	March 2012
HMP&L 2	March 2012	[redacted]
Wilson 1	September 2011	[redacted]

* In August, 2013, coinciding with the Century Aluminum power sales contract termination, the current outage plans depict the Wilson unit temporarily idled until Big Rivers can secure replacement load. Big Rivers is still evaluating this strategy and the current plan is subject to change. If the Wilson plant is not idled the deferred maintenance will be completed in [redacted]

Sincerely yours,

Mark A. Bailey

Mark A. Bailey
President and CEO
Big Rivers Electric Corporation

Attachments
c: Power Supply Division

USDA Rural Development

United States Department of Agriculture
Rural Development

DEC 27 2012

Mr. Mark A. Bailey
President & Chief Executive Officer
Big Rivers Electric Corporation
P. O. Box 24
201 Third Street
Henderson, Kentucky 42419-0024

Dear Mr. Bailey:

This is in response to the letter dated November 20, 2012, from Ms. Billie J. Richert, to Mr. John Padalino, Acting Administrator of Rural Utilities Service (RUS), regarding Big Rivers Electric Corporation's (Big Rivers) request for RUS approval to revise the depreciation rates as recommended in the Comprehensive Depreciation Study Report (Depreciation Study) prepared for Big Rivers by Burns & McDonnell Engineering Company, Inc. dated November 2012.

In the Depreciation Study, Burn & McDonnell stated on Page ES-3 that since the Unwind Closing 2009, Big Rivers has not performed major maintenance such as valve inspections and turbine generator inspections on a schedule consistent with prudent utility operations. This is not acceptable to RUS and Big Rivers needs to resume their scheduled major inspections and maintenance per prudent utility operations promptly. **Please let us know of your timeline for getting this matter resolved.**

We find that the depreciation rate analysis that was performed based on the electric generation and transmission historical plant records of Big Rivers as of July 31, 2012 is acceptable; therefore, RUS hereby approves the new depreciation rates for the electric generation and transmission asset of Big Rivers included in above Depreciation Study as follows:

Account	Description	Existing Rates	Proposed Rates
Steam Production Plant			
340	Land	N/A	N/A
311	Structures	1.38%	1.38%
312	Boiler Plant	1.88%	2.02%
312 A-K	Boiler Plant - Environmental Compliance	2.28%	2.43%
312 L-P	Short-Life Production Plant - Environmental	20.22%	15.95%
312 V-Z	Short-Life Production Plant - Other	14.39%	25.38%

314	Turbine	1.91%	1.96%
315	Electrical Equipment	1.99%	2.03%
316	Miscellaneous Equipment	3.78%	4.04%
Combustion Turbine (CT) Production Plant			
341	CT - Structures	1.17%	1.06%
342	CT – Fuel Holders & Accessories	9.10%	9.92%
343	CT – Prime Movers	3.02%	3.02%
344	CT - Generators	0.50%	0.35%
345	CT – Access. Electrical Equipment	2.05%	2.93%
Transmission			
350	Land	N/A	N/A
352	Structures	1.90%	1.94%
353	Station Equipment	2.23%	2.29%
354	Towers	1.42%	1.36%
355	Poles	2.06%	2.03%
356	Lines	1.69%	1.81%

Depreciation rates for General Plant type facilities may be based on a borrower's experience and these rates do not require RUS approval.

Please let us know if we can be of further assistance.

Sincerely,

CHRIS TUTTLE
Acting Deputy Assistant Administrator
Rural Utilities Service-Electric Program

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES	)))	**Case No. 2012-00535**

DIRECT TESTIMONY

OF

TED J. KELLY
PRINCIPAL, BURNS & McDONNELL

ON BEHALF OF

BIG RIVERS ELECTRIC CORPORATION

FILED: **January 15, 2013**

5. A discussion of the operating and maintenance procedures for each production facility;
6. An analysis of external factors that may impact each facility's useful life;
7. An opinion, based on the study's findings, regarding the remaining life of each facility;
8. A discussion of the composition of the transmission system; and
9. An opinion, based on the study's findings, regarding remaining life of each substation.

Q. How is this used to determine depreciation rates?

A. The remaining life of each facility is provided in the Engineering Assessment and is a component that is considered in the calculation of depreciation rates. One important component of determining the remaining life of Big Rivers' facilities involves an evaluation of the maintenance activities performed by Big Rivers and the resultant operating condition of the facilities.

Q. Did RUS comment on Big Rivers maintenance practices mentioned in the Depreciation Study Report?

A. Yes. RUS indicated that Big Rivers needs to resume its scheduled major inspections and maintenance practices. RUS may have misunderstood what we were indicating in the report. As a result of prevailing resource constraints, Big Rivers selectively deferred some major maintenance while continuing routine maintenance. Inspections performed by Burns & McDonnell and a review of operating results over the last several years indicated no adverse conditions as a result of this short term deferral. Burns & McDonnell did review Big Rivers' plans, developed in May 2012, to reschedule the maintenance activities that are described by Bob Berry in his testimony. In light of the favorable operating results and assuming timely rescheduling of the deferred maintenance, in our opinion Big Rivers showed good judgment in the use of available resources and its facilities are being reasonably and prudently operated.

E. Facilities Review

Q. What facilities were reviewed?

A. A description of each of the facilities physically inspected and reviewed by Burns & McDonnell is provided in the Engineering Assessment of the 2012 Depreciation Study. (*See* Exhibit Kelly-1, Tables II-1 through II-8, pp. II-2 through II-6.)

i. Robert D. Green Plant

Q. Describe the Robert D. Green facility.

A. The Robert D. Green Plant ("Green Plant") is located on the Sebree site near Sebree, Kentucky, along with the Robert A. Reid Plant ("Reid Plant") and Henderson Municipal Power & Light Station Two ("HMP&L Station

Entire Page is confidential and is redacted

Exhibit Holloway-5

Layup Adjustment for Wilson Depreciation Expenses

Layup Adjustment for Wilson Annual Depreciation Expenses

Proposed Depreciation Expenses	$19,203,299
Depreciation Expenses Adjusted for Layup	$16,295,508
Layup Adjustment	($2,907,791)

Note: Current Depreciation Expenses	$18,543,752

Table ES-1 Adjusted to Show Wilson Only Costs

Table ES-1: 2012 Wilson Depreciation Rates as Proposed

Account	Description	As of July 31, 2012			Existing Depreciation Rate	Average Service Life	Remaining Service Life	Net Salvage Factor	Proposed Depreciation Rate	Annual Depreciation Expense		
		Plant Balance	Reserve Balance	Reserve Ratio						Existing	Proposed	Variance
		- $ -	- $ -		- % -	- Years -	- Years -	- % -	- % -	- $ -	- $ -	- $ -
PRODUCTION PLANT [1]												
311	Structures	73,327,591	48,027,081	65.5	1.38%	62.0	28.2	-4.5%	1.38%	1,011,921	1,014,701	2,780
312	Boiler Plant	402,955,640	210,819,217	52.3	1.88%	59.5	26.1	-5.0%	2.02%	7,575,566	8,137,672	562,106
312 A-K	Boiler Plant - Environment Compliance	263,864,442	101,746,118	38.6	2.28%	53.0	26.3	-2.0%	2.41%	6,016,109	6,361,041	344,932
312 L-P	Short-Life Production Plant -Environmental	7,312,503	1,721,938	23.5	20.22%	10.0	4.8	0.0%	15.93%	1,478,588	1,164,701	(313,887)
314	Turbine	128,877,902	72,495,838	56.3	1.91%	59.5	26.5	-8.2%	1.96%	2,461,568	2,525,184	63,616
315	Electric Equipment	35,103,875	21,027,386	59.9	20.22%	50.9	18.3	0.0%	2.19%	7,098,004	769,207	(6,328,797)
316	Miscellaneous Equipment	1,255,086	16,017	1.3	14.39%	57.5	24.3	0.0%	4.06%	180,607	50,990	(129,616)
	Subtotal	$876,338,079	$434,810,193							$18,543,752	$19,203,299	$659,547

Note: Plant Balances from Amounts Provided in response to KIUC 2-20(a)
Reserve Ratios used to calculate Reserve Balance for Wilson Accounts

Table ES-1 Adjusted to Show Wilson Only Costs

Table ES-1: 2012 Wilson adjusted Depreciation Rates Adding 4 Years to Remaining Service Life for Layup

		As of July 31, 2012			Existing	Average	Remaining	Net	Proposed	Annual Depreciation Expense		
Account	Description	Plant Balance	Reserve Balance	Reserve Ratio	Depreciation Rate	Service Life	Service Life	Salvage Factor	Depreciation Rate	Existing	Proposed	Variance
		- $ -	- $ -		- % -	- Years -	- Years -	- % -	- % -	- $ -	- $ -	- $ -
PRODUCTION PLANT [1]												
311	Structures	73,327,591	48,027,081	65.5	1.38%	62.0	32.2	-4.5%	1.21%	1,011,921	888,651	(123,270)
312	Boiler Plant	402,955,640	210,819,217	52.3	1.88%	59.5	30.1	-5.0%	1.75%	7,575,566	7,056,254	(519,312)
312 A-K	Boiler Plant - Environment Compliance	263,864,442	101,746,118	38.6	2.28%	53.0	30.3	-2.0%	2.09%	6,016,109	5,521,300	(494,809)
312 L-P	Short-Life Production Plant -Environmental	7,312,503	1,721,938	23.5	20.22%	10.0	8.8	0.0%	8.69%	1,478,588	635,291	(843,297)
314	Turbine	128,877,902	72,495,838	56.3	1.91%	59.5	30.5	-8.2%	1.70%	2,461,568	2,194,012	(267,556)
315	Electric Equipment	35,103,875	21,027,386	59.9	20.22%	50.9	22.3	0.0%	1.80%	7,098,004	631,233	(6,466,771)
316	Miscellaneous Equipment	1,255,086	16,017	1.3	14.39%	57.5	28.3	0.0%	3.49%	180,607	43,783	(136,824)
	Subtotal	$876,338,079	$434,810,193							$18,543,752	$16,295,508	($2,248,244)

Note: Plant Balances from Amounts Provided in response to KIUC 2-20(a)
Reserve Ratios used to calculate Reserve Balance for Wilson Accounts
4 years added to remaining service life respresents Wilson forecasted layup

Exhibit Holloway-6

Allocation of Transmission Costs to Customer Classes

As Filed in Wolfram 4.2 (PSC 2-36 revision to Wolfram 4) Allocation of Transmission Costs to Customer Classes

	Notes	Rurals	Large Industrials	Alcan Smelter	Century Smelter	Total System
Transmission Revenue Requirement	1	$ 15,037,290	$ 3,994,404	$ 12,476,695	$ -	$ 31,508,389
12 CP Demand Allocators	2	5,322,297	1,413,779	4,416,000	-	11,152,076

Allocation of Transmission Costs if Century Continues to Operate as Transmission Only Customer

	Notes	Rurals	Large Industrials	Alcan Smelter	Century Smelter	Total System
Transmission Revenue Requirment	3	$ 9,901,763	$ 2,630,237	$ 8,215,660	$ 10,760,729	$ 31,508,389
12 CP with Century Smelter	4	5,322,297	1,413,779	4,416,000	5,784,000	16,936,076

Note
1. See page 16 of 16 of Wolfram 4.2
2. See page 13 of 16 of Wolfram 4.2
3. Calculated
4. From Coincident Peak forecasts provideed in response to AG 1-234