ORIGINAL

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

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

VOLUME 5 of 5

DIRECT TESTIMONY
[Application Tabs 63 through 73]

FILED: January 15, 2013

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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 ADJUSTMENT IN RATES	)))	Case No. 2012-00535

DIRECT TESTIMONY

OF

MARK A. BAILEY
PRESIDENT and CHIEF EXECUTIVE OFFICER

ON BEHALF OF

BIG RIVERS ELECTRIC CORPORATION

FILED: January 15, 2013

DIRECT TESTIMONY
OF
MARK A. BAILEY

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DIRECT TESTIMONY
OF
MARK A. BAILEY

I. INTRODUCTION

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

A. My name is Mark A. Bailey. I am employed by Big Rivers Electric Corporation ("Big Rivers"), 201 Third Street, Henderson, Kentucky 42420 as its President and Chief Executive Officer ("CEO"). I have held this position since October 2008. Before coming to Big Rivers, I was employed by Kenergy Corp. ("Kenergy") as its President and CEO for two years and prior to that by American Electric Power Company ("AEP") for nearly 30 years, beginning as an electrical engineer in 1974. A copy of my resume is attached hereto as Exhibit Bailey-1.

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

A. Yes. I most recently testified on Big Rivers' behalf in its last rate case, Case No. 2011-00036 (the "2011 Rate Case"), which is currently in the rehearing stage, and in Case No. 2010-00043, which was related to Big Rivers becoming a member in the Midwest Independent Transmission System Operator, Inc. ("MISO"). In addition, I have testified before state regulatory commissions in Arkansas, Texas, Louisiana, and Oklahoma.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is: (i) to introduce the witnesses that will testify on behalf of Big Rivers in this case, with a brief description of the topics that each witness will address; (ii) to provide an overview of Big Rivers' need for the rate relief requested in this proceeding; (iii) to provide a summary of Big Rivers' proposed rate requests; and (iv) to sponsor certain filing requirements from 807 KAR 5:001.

III. INTRODUCTION OF WITNESSES AND THEIR TESTIMONY

Q. Please identify the witnesses who will testify for Big Rivers and the areas which their testimony will address.

A. In addition to my testimony, Big Rivers presents the testimony of the following witnesses:

1) **Billie J. Richert** (Tab 64). Ms. Richert, Big Rivers' Vice President – Accounting and Interim Chief Financial Officer, explains the drivers behind the proposed rate increase. She describes Big Rivers' financial obligations, Big Rivers' need to have access to the capital markets, and the consequences of failing to meet its financial covenants. She provides an overview of the budget development

process that Big Rivers relied upon for producing this filing and for the on-going management of the utility. Ms. Richert also explains how the termination of the Century Aluminum of Kentucky General Partnership ("Century") power contract could affect Big Rivers' ability to operate and meet its financial obligations. Finally, Ms. Richert discusses Big Rivers' Economic Reserve, Rural Economic Reserve, and Transition Reserve accounts.

2) **Albert M. Yockey** (Tab 65). Mr. Yockey, Big Rivers' Vice President, Governmental Relations and Enterprise Risk Management, describes and sponsors the tariff changes Big Rivers is proposing. Mr. Yockey also details other proceedings that might impact this case, describes Big Rivers' management of the costs associated with this proceeding, and describes Big Rivers' current demand-side management ("DSM") and energy efficiency programs.

3) **Robert W. Berry** (Tab 66). Mr. Berry, Big Rivers' Vice President of Production, describes Big Rivers' generating assets and the performance of the generating units. He also explains why it is absolutely essential that Big Rivers' rates are sufficient to enable Big Rivers to perform an appropriate level of plant maintenance. He supports Big Rivers' request to recover certain expenses resulting from its MISO membership, explains Big Rivers' efforts to mitigate

the effects of the Century contract termination, and briefly describes Big Rivers' production cost modeling and load forecast.

4) **David G. Crockett** (Tab 67). Mr. Crockett, Big Rivers' Vice President, System Operations, provides an overview of the Big Rivers transmission system and supports the level of transmission-related capital and fixed departmental expense ("FDE")-related operation and maintenance ("O&M") expense included in the budget results for 2013 and 2014. Mr. Crockett also describes the status of the transmission projects known as the Phase 2 transmission projects.

5) **DeAnna M. Speed** (Tab 68). Ms. Speed, Big Rivers' Manager-Budgets, explains the development of Big Rivers' annual budget and financial plan, including the budget results for 2013 and 2014.

6) **Lindsay N. Barron** (Tab 69). Ms. Barron, Big Rivers' Managing Director, Energy Services, describes the development of Big Rivers' load forecast.

7) **James V. Haner** (Tab 70). Mr. Haner, Big Rivers' Vice President Administrative Services, describes the role of Administrative Services in the development of Big Rivers' budget. Mr. Haner also describes how Big Rivers estimated severance costs associated with the anticipated idling of a generating plant.

8) **Ted J. Kelly** (Tab 71). Mr. Kelly, a Principal at the firm of Burns & McDonnell, sponsors the Burns & McDonnell Report on the

Comprehensive Depreciation Rate Study prepared for Big Rivers in order to comply with the November 17, 2011, Order in the 2011 Rate Case, which required Big Rivers to conduct a new depreciation rate study as part of this case.

9) **Travis A. Siewert** (Tab 72). Mr. Siewert, a Senior Staff Accountant for Big Rivers, describes the Big Rivers financial model that is used in the Big Rivers budgeting process.

10) **John Wolfram** (Tab 73). Mr. Wolfram, Principal of Catalyst Consulting LLC, describes and sponsors a cost of service study and describes Big Rivers' revenue requirement, the proposed allocation of the revenue increase, the proposed rates, and the percentage increase by rate class.

IV. BIG RIVERS' NEED FOR RATE RELIEF

Q. Please describe Big Rivers' present financial condition and the need for additional revenue.

A. Big Rivers is in a precarious financial position. Big Rivers current rates will not produce sufficient revenue for Big Rivers to continue to prudently maintain its generating units while achieving even the minimum 1.10 margins for interest ratio ("MFIR") required by Big Rivers' loan agreements, largely as a result of the continued decline in wholesale power market prices. Big Rivers has so far dealt with its depressed off-system sales revenues, from which Big Rivers derives almost all of its margins, through corporate-wide cost cutting, by reducing plant maintenance and deferring outages, and by filing the 2011 Rate Case. That situation is at a breaking point, as explained in the Direct Testimony of Mr. Robert W. Berry. Big Rivers must have the full amount of the increase it is seeking in this case so that it can continue to perform a prudent level of maintenance.

Unfortunately, an even more pressing problem looms. On August 20, 2013, Century's power contract terminates. Century currently represents nearly 40% of the internal load on the Big Rivers system. Big Rivers is seeking an increase in this proceeding to eliminate a $74,476,120 revenue deficiency. The Century contract termination represents approximately $63 million of that revenue deficiency.

There are other major drivers of the revenue deficiency. They include the declining off-system sales margins described above and depreciation rates recommended by the depreciation study required by the Commission as part of this proceeding. Offsetting those amounts are the effects of the July 2012 refinancing of Rural Utilities Service ("RUS") debt and other less significant items. Big Rivers estimates these items have a net impact of approximately $11 million, and they are further described in the Direct Testimony of Ms. Billie J. Richert.

The bottom line is that Big Rivers needs the full amount of the increase it is seeking. Big Rivers must demonstrate to the rating agencies regulatory support of Big Rivers' financial health. The proposed rate increase should allow Big Rivers to have access to the capital markets, to continue to appropriately maintain its utility plant, and to meet the requirements of its loan agreements, which, among other things, obligate Big Rivers to achieve at least a 1.10 MFIR and to maintain at least two investment grade credit ratings.

To reiterate, Big Rivers is requesting a rate increase principally to cover revenues lost from Century's termination and a decline in the off-system sales market. Big Rivers has experienced some increase in expenses; however, it has managed those increased expenses by reducing others.

It is important to note that Century and Alcan Primary Products Corporation ("Alcan") (Century and Alcan are together referred to herein as the "Smelters") are served through special contracts (the "Smelter Agreements") that effectively limit Big Rivers to a 1.24 times interest earned ratio ("TIER"), as TIER is defined in the Smelter Agreements ("Contract TIER"). This cap and the requirements of Big Rivers' loan agreements are further explained in the Direct Testimony of Ms. Billie J. Richert.

For the test period, the difference in net margins between Big Rivers making a 1.24 Contract TIER and a having MFIR fall below 1.10 is only about $7 million. For a company with $557 million in annual cost of service for 2011, that is a very slim margin of error. Big Rivers has only been able to satisfy the MFIR requirement thus far by dramatically cutting costs and deferring maintenance. But Big Rivers cannot relieve the projected revenue deficiency through cost savings alone. The approximately $63 million impact of the Century contract termination, not to mention the rest of the $74.5 million that Big Rivers must have, far exceeds any amount of cost savings that Big Rivers can extract from the business. Simply put, Big Rivers has no way to offset this revenue shortfall with cost-cutting initiatives. The only way Big Rivers can make up the $74.5 million revenue shortfall in the immediate term is to increase base rates as proposed in this case.

Maintaining two investment-grade credit ratings is also very important to Big Rivers. As further explained in the Direct Testimony of Ms. Billie J. Richert, not only do Big Rivers' loan agreements require it to maintain two investment grade credit ratings, but if Big Rivers loses its investment grade credit ratings, it will be in danger of not being able to attract the capital in the financial markets that Big Rivers must have to run its business and to satisfy its debt obligations. Big Rivers' proposed rates are based on a 1.24 Contract TIER, which is low for an investment grade-rated generation and transmission ("G&T") cooperative. It is especially low given the negative credit consequences arising from Century's notice that it was terminating its contract. As a result of that notice, one rating agency downgraded Big Rivers' rating, and all three placed Big Rivers' rating on negative watch. Big Rivers is now at the lowest or next to lowest investment grade rating from all three ratings agencies. As Ms. Richert explains in her testimony, Big Rivers is not aware of any G&T cooperative with a rating below the investment grade level that has financed in the capital markets.

Ms. Richert also notes that in explaining its negative watch, Moody's Investor Services explained the factors that could cause a downgrade in Big Rivers' credit rating by stating that "[l]oss of significant load due to Century's announcement that is not otherwise compensated for through off system power sales or other measures could contribute to a negative action, as would the inability to secure needed rate increases from the non-smelter member load." Similarly, Fitch Ratings said that the factors that could cause it to downgrade Big Rivers' credit rating include "[i]nsufficient regulatory support: Inadequate or untimely support by the Kentucky Public Service Commission (KPSC) would be viewed negatively."

In short, I simply cannot stress enough how important it is for Big Rivers to receive the full amount of the increase it is seeking. The rates Big Rivers proposes are absolutely necessary, fair, just, and reasonable.

Q. What if Big Rivers is able to sell the power it will have as a result of the Century contract termination?

A. Big Rivers is and has been evaluating ways to mitigate the effects of the Century contract termination, as described in the Direct Testimony of Mr. Robert W. Berry. As and when those mitigation efforts are successful, Big Rivers' members will benefit. But those benefits are not expected to materialize for at least three years, and under the current wholesale market conditions, Big Rivers' best option at this time for mitigating the impact of the Century contract termination is to idle a generating plant to reduce expenses, as further explained in the Direct Testimony of Mr. Robert W. Berry.

V. <u>OVERVIEW OF RATE REQUESTS</u>

Q. How did Big Rivers develop the rates proposed in this proceeding?

A. Big Rivers conducted a fully allocated embedded cost of service study to develop the proposed rates. The costs of service and proposed rates are described in detail in the Direct Testimony of Mr. John Wolfram, but essentially, the proposed rates are designed to generate the $74.5 million revenue deficiency and eliminate the subsidy currently received by the Rural Delivery Service ("RDS") rate class (the "Rurals"). The proposed rates represent an increase to the Rurals of $40,676,278; an increase to the

Large Industrial Customer ("LIC") rate class ("Large Industrials") of $8,247,929; and an increase to the Smelter rate class of $25,551,913.

Q. Why is Big Rivers proposing to eliminate the subsidy currently received by the Rurals?

A. Generally, Big Rivers believes it is appropriate to eliminate interclass subsidies, and in that regard, Big Rivers proposed to eliminate some of the interclass subsidy paid by the Smelters to the Rurals in the 2011 Rate Case. In the interest of fairness to all rate classes, Big Rivers believes it is appropriate at this time to eliminate the remaining subsidy received by the Rurals so that the impact of the proposed rate relief, including the impact of the Century contract termination, is shared by all classes on a cost-of-service basis.

Q. What are the proposed charges for the Rurals?

A. Big Rivers is proposing to increase the demand charge from $9.5000 per kW per month to $16.9500 per kW per month (billed on the basis of CP demand). Big Rivers is proposing to increase the energy charge from $0.029736 per kWh to $0.030000 per kWh.

Q. What are the proposed charges for the Large Industrials?

A. Big Rivers is proposing to increase the demand charge from $10.5000 per kW per month to $12.4100 per kW per month and to increase the energy charge from $0.024505 per kWh to $0.030000 per kWh.

Q. How are the Base Rates for the Smelter class determined?

A. The Base Rate rates for the Smelter rate class (which will only include Alcan after the Century contract termination) are determined by the Smelter Agreements and are derived by applying the Large Industrial Customer rate to a load with a 98 percent load factor, plus a $0.25 per MWh adder.

Q. How will the proposed rate increases affect the retail rates of Big Rivers' members?

A. As shown in the direct testimony of Mr. John Wolfram, Big Rivers estimates that on average its proposed rate increase will result in a retail rate increase of approximately 19% for a typical residential customer with a monthly usage of 1,300 kWh. Obviously, this is a rough estimate of the impact of Big Rivers' proposed increase on retail rates; the actual retail percentage increase will vary by individual distribution cooperative member depending upon its individual sales characteristics and retail rate structure.

Q. How do the proposed rates address the issue of subsidization between rate classes?

A. The proposed rates are designed to entirely eliminate the cost-of-service subsidies received by the Rural rate class. This is explained in the Direct Testimony of Mr. John Wolfram.

VI. FILING REQUIREMENTS

Q. Have you reviewed the answers provided in Tabs 1-62, which address Big Rivers' compliance with forecasted period filing requirements under 807 KAR 5:001 and its various subsections?

A. Yes. I have, and I hereby incorporate and adopt those portions of Tabs 1-62 for which I am identified as the sponsoring witness as part of this testimony.

Q. Are you Big Rivers' chief officer in charge of Kentucky operations?

A. Yes. As Big Rivers' President and CEO, I am Big Rivers' chief officer in charge of Kentucky operations.

Q. Please describe Big Rivers' existing programs to achieve improvements in efficiency and productivity, including an explanation of the purpose of the programs, pursuant to 907 KAR 5:001 Section 10(9)(a).

A. Big Rivers continues to look for ways to reduce unnecessary costs, to improve the efficiency of its generating units, and to offer a robust set of DSM and energy efficiency programs. Big Rivers monitors its costs and has engaged in corporate-wide cost cutting. The Direct Testimony of Mr. Robert W. Berry shows that Big Rivers' generating units have performed well, and Big Rivers' production department continues to seek improvements to generator efficiency. The Direct Testimony of Mr. Albert M. Yockey describes Big Rivers' DSM and energy efficiency measures. The purpose of these programs is to provide low cost, reliable power to Big Rivers' members.

VII. CONCLUSION

Q. Do you have any closing comments?

A. Yes. For the reasons stated above and in the testimonies of the other Big Rivers witnesses, the entire amount of Big Rivers' proposed rate relief is absolutely necessary. Big Rivers must demonstrate to the rating agencies regulatory support of Big Rivers' financial health. The proposed rate increase should allow Big Rivers to have access to the capital markets, to continue to appropriately maintain its utility plant, and to meet the requirements of its loan agreements, which, among other things, obligate Big Rivers to achieve at least a 1.10 MFIR and to maintain at least two investment grade credit ratings. As such, the proposed rates are fair, just, and reasonable.

Q. What are your conclusions and recommendations to the Commission in this proceeding?

A. The rates proposed by Big Rivers are absolutely necessary and are fair, just, and reasonable and should be approved by the Commission.

Q. Does this conclude your testimony?

A. Yes.

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2012-00535

VERIFICATION

I, Mark A. Bailey, verify, state, and affirm that I prepared or supervised the preparation of my testimony filed with this Verification, and that testimony is true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Mark A. Bailey
Mark A. Bailey

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Mark A. Bailey on this the 9th day of January, 2013.

Paula Mitchell
Notary Public, Ky. State at Large
My Commission Expires 1-12-17

MARK ALAN BAILEY

P.O. Box 24 – 201 Third Street
Henderson, Kentucky 42419

Big Rivers Electric Corp. Henderson, Kentucky June 2007 – present	**President & CEO** •Responsible to an elected 6 member board who represent Big Rivers' 3 distribution cooperative members for all facets of the Generation & Transmission cooperative's operations. Big Rivers owns and operates 5 coal-fired generating stations with a capacity of 1,444 MW and 1,262 miles of transmission lines. In addition, the company operates a two unit, 312 MW power station owned by Henderson Municipal Power & Light. The company employs ~ 615, has annual sales of ~ 12,000,000 MWh that produce annual revenue of ~ $510 million, with net assets of ~ $1.5 billion
Kenergy Corp. Henderson, Kentucky May 2004 – May 2007	**President & CEO** •Responsible to an elected 11 member board for all facets of operations of a distribution electric cooperative serving approximately 54,000 members including 19 large industrial customers in portions of 14 counties in western Kentucky with ~ 160 employees, a peak demand of approximately 1,200 MW, annual kwh sales in excess of 9.4 billion, $300 million in annual revenue, and $210 million in assets
American Electric Power Service Corporation Columbus, Ohio June 2000 – April 2004	**Vice President Transmission Asset Management** •Managed AEP's $2.5B transmission and substation assets located in eleven states, including $100M annual O&M and $250M capital expenditure decisions, as well as engineering and maintenance standards, annual maintenance and capital plans, development of strategic, business and incentive plans, system planning and interconnection agreements, regulatory and legislative policy formation and testimony, and all transmission related contracts
American Electric Power Service Corporation Columbus, Ohio Jan. 1998 – May 2000	**Managing Director, Energy Delivery and Customer Relations** •Responsible for administration of the Energy Delivery and Customer Relations business group consisting of the Transmission, Distribution, Marketing, System Operations, Public Relations, Regulatory functions and the state Presidents' offices including development of strategic, business and incentive plans, operational metrics, performance targets and monitoring systems •Managed Transmission and Distribution Materials Management organization. • Testified before 4 state Commissions in support of AEP's merger w/ CSW
American Electric Power Service Corporation Columbus, Ohio Jan. 1996 – Dec. 1997	**Director – Regions** •Directed the reorganized AEP's six southern distribution regions serving nearly 1,300,000 customers in portions of 5 states with 2,700 company and 2,500 contractor employees •Oversaw the Transmission and Distribution Materials Management organization
Indiana Michigan Power Fort Wayne, Indiana Oct. 1994 - Dec. 1995	**Vice President, Administration** •Oversaw Marketing, Customer Services, Accounting, Rates, and Purchasing and Materials Management Departments as well as the Budgeting Section •Chaired the company's Political Action Disbursements Committee •Coordinated operating company administrative support for the company's three coal fired and one nuclear generating stations (6,200MW)

MARK ALAN BAILEY

Indiana Michigan Power Fort Wayne, Indiana 1989 – Sept. 1994	**Vice President, Operations** •Directed four operating divisions serving nearly 520,000 customers in 28 counties in Indiana and Michigan and a total of ~ 1,300 employees •Oversaw Transmission and Distribution, Purchasing and Materials Management, System Operations, General Services and Land Management Departments at corporate headquarters •Coordinated operating company administrative support for the company's three coal fired, one nuclear and five hydro power plants (6,200MW)
Ohio Power Columbus, Ohio 1988 – 1989	**Executive Assistant to the President** •Assisted the AEP Executive Vice President – Operations performing studies and analyses such as ramifications of merging Ohio Power and Columbus Southern Power operating companies and design of a management incentive compensation system •Lobbied on behalf of Ohio Power with the Ohio General Assembly
Ohio Power Cambridge, MA 1987 – 1988	**Division Manager** •Completed course work leading to attainment of a Masters Degree in Management as a Sloan Fellow at the Massachusetts Institute of Technology
Ohio Power Tiffin, Ohio 1985 – 1987	**Division Manager** •Managed all aspects of providing electrical service to 58,000 customers through five operating units consisting of 210 employees
Ohio Power Canton, Ohio 1983 – 1985	**Administrative Assistant to the President** •Coordinated operating company administrative support for the company's five fossil fired power plants (8,120 MW) •Oversaw operation and maintenance of the company's two unit, 48 MW hydro plant •Assisted the President with various studies and assignments including periodic participation in the AEP/Buckeye Power (Cardinal Plant) Operating Committee
Cardinal Operating Co. Cardinal Plant Brilliant, Ohio 1981 - 1983	**Performance Superintendent** •Directed department of 65 employees responsible for installation and maintenance of the plant's instruments and controls, engineering and thermal performance, and laboratory operations at the three unit, coal fired 1,860 MW plant. This is a jointly-owned plant by Buckeye Power & AEP operated by AEP. •Directly supervised start-up & shut-downs of the 600 MW supercritical units
Ohio Power Muskingum River Plant Beverly, Ohio 1979 - 1981	**Production Superintendent** •Directed department responsible for operations of a five unit, coal fired 1,460 MW plant •Directly supervised start-ups & shut-downs of the plant's 600 MW supercritical unit, wrote plant operating procedures and trained operators following major modifications of the 600 MW Unit 5 steam generator & precipitator addition
Ohio Power Gavin Plant Cheshire, Ohio 1975 - 1979	**Performance Engineer** •Various engineering positions of increasing responsibility at the two unit, 2,600 MW coal fired plant. Major areas of involvement included analyzing thermal performance, instrument and control installation and maintenance •Wrote plant operating procedures for all the AEP system's 1,300 MW supercritical units

MARK ALAN BAILEY

Ohio Power Portsmouth, Ohio 1974 – 1975	**Electrical Engineer** •Designed, laid out and specified material for construction of distribution facilities to serve retail customers in the Portsmouth division
Education:	•The Massachusetts Institute of Technology, Cambridge, Massachusetts Masters of Science in Management, 1988 •The Ohio Northern University, Ada, Ohio Bachelor of Science in Electrical Engineering with Distinction, 1974
Honors and Activities:	•Member of Tau Beta Pi National Engineering Honorary •Member - Order of Kentucky Colonels •Board member - Methodist Hospital, Henderson, Kentucky •Board member – Methodist Hospital Foundation •Board member – Henderson Community & Technical College Foundation •Board member – Kentucky Community & Technical College Foundation

January 2013

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

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

DIRECT TESTIMONY

OF

BILLIE J. RICHERT
VICE PRESIDENT, ACCOUNTING and
INTERIM CHIEF FINANCIAL OFFICER

ON BEHALF OF

BIG RIVERS ELECTRIC CORPORATION

FILED: January 15, 2013

DIRECT TESTIMONY
OF
BILLIE J. RICHERT

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DIRECT TESTIMONY
OF
BILLIE J. RICHERT

I. INTRODUCTION

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

A. My name is Billie J. Richert. I am employed by Big Rivers Electric Corporation ("Big Rivers"), 201 Third Street, Henderson, Kentucky 42420, as the Vice President – Accounting and Interim Chief Financial Officer.

Q. Please describe your job responsibilities.

A. I am responsible for all aspects of the budgeting, accounting, finance, information systems and reporting functions for Big Rivers. I report directly to the Chief Executive Officer.

Q. Briefly describe your education and work experience.

A. I assumed my current role in July of 2012. I have been employed by Big Rivers since July 2010, first as the Oracle Accounting System Administrator and then as the Manager of Business Systems Infrastructure. I earned a Bachelor of Science degree in Accounting from Indiana University and a Master of Management, Finance from Northwestern University. I am a licensed Certified Public Accountant ("CPA") and a Certified IT Professional ("CITP"). Prior to my employment at Big Rivers, I served as Director of Financial Systems at DePauw

University. A summary of my education and work experience is attached as Exhibit Richert-1.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to (i) provide an overview of the rate filing, (ii) describe the drivers for the proposed rate increase, (iii) provide an overview of the budget development process that Big Rivers relied upon for producing this filing and for the on-going management of the utility; (iv) describe the obligations Big Rivers has to its creditors in meeting its financial covenants; (v) describe the implications of the termination of the Century Aluminum of Kentucky General Partnership ("Century") power contract on Big Rivers' financial obligations and on Big Rivers' ability to attract necessary capital to provide electric service to its members; and (vi) sponsor certain filing requirements from 807 KAR 5:001.

Q. Are you sponsoring any exhibits?

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

1. Exhibit Richert-1 Professional Summary for Billie J. Richert;
2. Exhibit Richert-2 G&T Comparison Analysis;
3. Exhibit Richert-3 RUS Approval Letter for Depreciation Rates;

4. Exhibit Richert-4 Cross-Reference to PSC Cases in which Financing Documents are Filed;
5. Exhibit Richert-5 Principal Financial Covenant Excerpts;
6. Exhibit Richert-6 MFIR Calculation; and
7. Exhibit Richert-7 Credit Rating Agencies' Reports.

III. OVERVIEW

Q. Please provide an overview of the request of Big Rivers in this proceeding.

A. In this proceeding Big Rivers is seeking approval for an increase of \$74,476,120 in rates to eliminate Big Rivers' revenue deficiency in the same amount based on test period revenues and expenses. Big Rivers estimates that the vast majority of this amount -- approximately \$63 million -- stems from the termination of a single special contract with an aluminum smelter customer. Additional major drivers (which Big Rivers estimates have a net impact of approximately \$11 million) include declining off-system sales margins and increasing depreciation expense; offsetting these drivers are the effects of the July 2012 refinancing of Rural Utilities Service ("RUS") debt and other less significant items. I describe these components in further detail below. The contract termination noted above places Big Rivers in a very precarious position from a finance and credit standpoint. The total increase is necessary to allow Big Rivers to meet its financial obligations to its creditors and to attract necessary capital in order to provide service to our members in 2013 and beyond.

Q. Is Big Rivers using a historical test period or forecasted test period in this filing?

A. Big Rivers is filing revenue requirements based on a fully forecasted test period corresponding to the 12 months beginning September 1, 2013, and ending August 31, 2014.

Q. What is the Times Interest Earned Ratio ("TIER") that Big Rivers is requesting?

A. Big Rivers is requesting a "Contract TIER" of 1.24. "Contract TIER" is defined in the agreements that relate to electric service provided to the two aluminum smelters, Century and Alcan Primary Products Corporation ("Alcan") (Alcan and Century are collectively referred to herein as the "Smelters;" the agreements are referred to as the "Smelter Agreements"). In its November 17, 2011, Order (the "November 17 Order") in Big Rivers' last rate case, Case No. 2011-00036 (the "2011 Rate Case"), the Commission accepted the use of the 1.24 Contract TIER.

Q. What is Big Rivers' Contract TIER?

A. TIER is the quotient, for a fiscal year, of (a) interest expense on long-term debt plus net margins, divided by (b) interest expense on long-term debt. Section 4.7.5 of the Smelter Agreements provides for a TIER Adjustment charge that effectively limits Big Rivers' margins to a 1.24 Contract TIER, subject to defined Adjustments.

Q. What are the distinctions among the definitions of TIER, Contract TIER and Margins for Interest Ratio ("MFIR") that are used in your testimony and referred to in the testimony of others in this case?

A. The distinctions can be shown using simplified formula definitions of each term:

- TIER (Times Interest Earned Ratio) = (Net Margins + Interest Expense on Long Term Debt) / Interest Expense on Long Term Debt
- Contract TIER = TIER as adjusted by Section 4.7.5 of the Smelter Agreement with a maximum of 1.24
- MFIR (Margins For Interest Ratio) = (Net Margins + Interest Expense on Long Term Debt + Income Tax) / Interest Expense on Long Term Debt

Q. Conceptually, how do you consider MFIR and Contract TIER as they relate to Big Rivers' financial performance?

A. As I explain later in my testimony, the MFIR serves as a floor or a lower bound for Big Rivers' financial performance, and the Contract TIER can be considered a ceiling or an upper bound for Big Rivers' financial performance. Even though the MFIR and Contract TIER are not strictly identical in a formulaic sense, they are similar enough to consider them conceptually as the boundaries of a very narrow band of financial performance that Big Rivers must attain.

Q. Why is it reasonable for Big Rivers' to propose rates based on achieving the 1.24 Contract TIER in this proceeding?

A. The use of the 1.24 Contract TIER is consistent with the October 2008 Unwind Financial Model filed with the Commission as Exhibit No. 79 in Case No. 2007-00455 (the case in which the Commission approved the "Unwind Transaction"), and, as noted above, with the Commission's November 17 Order in the 2011 Rate Case.

Pursuant to the Smelter Agreements, 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 Big Rivers non-smelter rate classes (i.e. the Rural Delivery Service ("RDS") and Large Industrial Customer ("LIC") rate classes (the "Non-Smelters")) and Smelters alike through a rebate (subject to the approval of the Big Rivers Board of Directors and the Commission). Therefore, Big Rivers' margins are essentially capped at a 1.24 Contract TIER. But if Big Rivers' TIER falls too low, then Big Rivers will be at risk of failing to maintain two investment grade credit ratings from Moody's, S&P or Fitch, putting at risk its ability to borrow necessary capital, and, in extreme cases, failing to meet its MFIR requirements, as set forth in its long-term debt agreements, and as I discuss in greater detail later in my testimony.

With respect to its financial performance, Big Rivers has a narrow range in which to operate. Generally, Big Rivers cannot practically achieve a Contract TIER greater than 1.24 – which, it should be emphasized, is a fairly low ceiling for a generation and transmission cooperative ("G&T"). For 2011, the average TIER or MFIR for G&Ts with debt ratings in the "A" and "B" category is 1.60. Big Rivers' 2011 TIER of 1.12 is the lowest TIER earned by any of the rated G&Ts reported in the G&T Accounting & Finance Association Annual Directory dated June 2012. This is evident from the data provided in Exhibit Richert-2, which is a table of G&Ts with investment-grade credit ratings and their TIER or MFIR (as of June 2012).

It is important that Big Rivers establish base rates in this proceeding that will provide it with a reasonable opportunity to achieve a 1.24 Contract TIER, which should allow Big Rivers to maintain its investment grade credit ratings, attract capital at reasonable interest rates, and appropriately maintain its utility plant. This would also eliminate the struggle Big Rivers is having to achieve a minimum MFIR of 1.10. If this is not accomplished, Big Rivers faces potential consequences that range from having to pay higher interest rates on debt, to being unable to find sources of credit and defaulting under its credit agreement covenants.

Q. Why is Big Rivers proposing rates based on achieving the 1.24 Contract TIER rather than proposing rates designed to achieve the 1.10 MFIR?

A. The 1.10 MFIR is a minimum requirement under Big Rivers' credit agreements, not a target that allows Big Rivers to operate and maintain its plants appropriately and attract capital. Achieving only a 1.10 MFIR beyond 2013 after the conclusion of this rate case would almost certainly result in Big Rivers not maintaining two investment grade credit ratings. This is especially true in light of the Century notice of termination, given that all three ratings agencies put Big Rivers' credit rating on negative watch as a result of that notice and are very focused on the outcome of this case, as I discuss later in my testimony. The higher the revenue increase that is awarded in this proceeding, the higher the TIER that Big Rivers is likely to achieve, and the more likely Big Rivers will be able to maintain its investment grade credit ratings, maintain the ability to have access to the credit markets, to borrow at favorable interest rates, and to properly maintain its utility plant. The lower the revenue increase that is awarded in this proceeding, the lower the TIER that Big Rivers is likely to achieve, and the more likely Big Rivers will suffer in all those respects. Big Rivers is proposing rates based on the 1.24 Contract TIER, and not based on the 1.10 MFIR, in order to avoid these adverse consequences. Even with rates on a Contract TIER of 1.24, there is very little room for negative variance from Big Rivers' budget.

IV. DRIVERS FOR RATE FILING

Q. Why is Big Rivers seeking the $74,476,120 increase in rates at this time?

A. Big Rivers requires this increase to rates at this time for several reasons. I will describe the primary driver first. Big Rivers and its Member Kenergy Corp. ("Kenergy") provide approximately 850 MW to the Smelters under the Smelter Agreements. On August 20, 2012, Century issued a notice terminating its retail service contract with Kenergy for Century's Hawesville, Kentucky smelter facility in 12 months. When that termination takes effect on August 20, 2013, the Century retail contract termination will create a substantial and immediate reduction in revenue for Big Rivers. Big Rivers estimates that the Century contract termination accounts for approximately $63 million of the $74.5 million revenue deficiency and request in this case. This amount is detailed in the Direct Testimony of Mr. Robert W. Berry. All else being equal, and absent the proposed rate increase to Big Rivers' remaining customer classes, this revenue shortfall alone would prevent Big Rivers from meeting its financial obligations to its creditors, and would not provide sufficient revenue for Big Rivers to operate its facilities. There are simply no expense areas where the potential savings could come close to offsetting this revenue loss. This places Big Rivers in a very precarious position from a credit and financing standpoint; I discuss this in more detail later in my testimony. For these reasons, the approximately $63 million revenue requirement resulting from the Century contract termination simply must be granted to keep Big

Rivers whole and to avoid exacerbating the other urgent credit issues facing Big Rivers at this juncture.

Q. Are there other drivers for the proposed rate increase?

A. Yes. Big Rivers' margins from off-system sales continue to decline. In the 2011 Rate Case, the test period off-system sales net sales margin was $19.4 million (for the twelve months ended October 31, 2010). In the instant case, for the twelve months ended August 31, 2014, the off-system sales net sales margin is projected to be $4.4 million. This amounts to a decrease of approximately $15 million in off-system sales net sales margin for the instant case relative to Big Rivers' last rate case. This is in spite of the fact that Big Rivers' generating units are available and running more often than they would be if Big Rivers were not deferring, reducing, and cancelling plant outages, as is explained in the Direct Testimony of Mr. Robert W. Berry.

Additionally, the November 17 Order in the 2011 Rate Case required Big Rivers to perform a new depreciation study as part of this case. As a result of that study, Big Rivers is proposing new, increased depreciation rates in this case. When Big Rivers updated the existing depreciation rates with the new depreciation rates, annual depreciation expense increased by approximately $2 million. The reasons for the changes in depreciation rates are described in the Direct Testimony of Mr. Ted J. Kelly.

On the positive side, Big Rivers estimates that the July 2012 refinancing of RUS debt will provide expense savings that offset the annual revenue deficiency by approximately $4 million. Other less significant positive factors are described in the direct testimony of several witnesses or are supported by the filing requirements filed with this application.

Q. Is it possible for Big Rivers to explicitly quantify each driver noted above such that the sum reconciles to the revenue deficiency of $74,476,120?

A. No. The revenue deficiency is not determined by summing the estimated impacts of various rate case drivers. Instead, the revenue deficiency is calculated by determining the increase in Big Rivers' margins that is necessary to achieve a Contract TIER of 1.24 for the fully forecasted test period, as described in the Direct Testimony of Mr. John Wolfram and as detailed in his Exhibit Wolfram-2. The discussion of rate case drivers here is simply intended to explain the main business reasons for the revenue deficiency, in broad but approximately quantified terms. It should not be interpreted as a strict reconciliation of the revenue deficiency, but instead should be considered as a guide to more fully understanding Big Rivers' present situation and the reasons for it.

Q. Is the need for a base rate increase in addition to the amounts related to the Century contract termination entirely unexpected?

A. No. In March of 2011, Big Rivers filed to increase its base rates to offset a revenue deficiency of $39,324,089 in the 2011 Rate Case. The primary driver for the revenue deficiency in that case was depressed off-system sales margins. In the November 17 Order in that case, the Commission granted Big Rivers a revenue increase of $26,744,776 per year – an amount $12,579,313 less than Big Rivers' original request of $39,324,089. Big

Rivers filed for rehearing of certain elements of the November 17 Order, and the rehearing is still pending. Although Big Rivers has secured some additional net cost savings since that case, the off-system sales market has not improved and in fact has declined further, so Big Rivers remains in the position of requiring a base rate increase *in addition to* the increase required to mitigate the revenue impact of the Century contract termination.

Q. Why was the fully forecasted test period of September 1, 2013, through August 31, 2014, selected?

A. This test period was selected because it is the first full twelve calendar months following the termination of the Century contract, and is thus representative of Big Rivers' expected operations and financial condition after that date. The fully forecasted test period is obviously better suited than the historic test period for capturing the significant changes to Big Rivers' operations and financial performance that will result from the Century contract termination.

V. OVERVIEW OF BUDGET DEVELOPMENT

Q. How was the budget for the fully forecasted test period developed?

A. The budget for 2013 and 2014 (and therefore for the fully forecasted test period of September 1, 2013, through August 31, 2014) was developed in accordance with Big Rivers' standard business policies and procedures for developing its budget and financial plan. This process is described in detail in the Direct Testimony of Ms. DeAnna M. Speed. Budget development began in the second quarter of 2012 and continued throughout the year. The final proposed budget was presented to Big Rivers' Board of Directors and approved on November 16, 2012.

Q. What are the key inputs to the Big Rivers budget, as described in detail by other witnesses in this filing?

A. The Big Rivers financial model described in the Direct Testimony of Mr. Travis A. Siewert is an integral component of the budget development process. Data from the budget and from the Big Rivers financial model are used in the derivation of the $74,476,120 revenue deficiency. Outputs from the load forecast described in the Direct Testimony of Ms. Lindsay N. Barron are used in the Big Rivers financial model. Labor and labor-related cost information described in the Direct Testimony of Mr. James V. Haner is an input to the budget. The depreciation rates provided by the Burns & McDonnell study and described in the Direct Testimony of Mr. Ted J. Kelly are used as an input to the Big Rivers financial model. Capital and operating expense projections and production cost modeling outputs described in the Direct Testimony of Mr. Robert W. Berry and the Direct Testimony of Mr. David G. Crockett are used as inputs to the Big Rivers financial model and to the budgeting process. Information from the Big

Rivers financial model, from the budget, and from the load forecast are used as inputs to the cost of service study described in the Direct Testimony of Mr. John Wolfram. Other components of the Big Rivers budget development process are described in the Direct Testimony of Ms. DeAnna M. Speed.

Q. How did Big Rivers select Burns & McDonnell to perform the depreciation study used in this filing?

A. In the Commission's November 17 Order in that docket, ordering paragraph 8 stated that "Big Rivers shall perform a new depreciation study within five years of the date of this order, *or the filing of its next rate case*, whichever is earlier" (emphasis added). On August 7, 2012, Big Rivers issued a Request for Proposal ("RFP") for a depreciation study to nine bidders. Six bidders responded. Of the six, five were solicited on September 27, 2012, to expedite the completion of the depreciation study by the second week in November. This was necessary for Big Rivers to obtain the required RUS approval of any depreciation rate changes in time to meet the target rate case filing date of January 15, 2013. Due to high pricing, one bidder was not solicited for an expedited report delivery. Burns & McDonnell, of Kansas City, Missouri, was selected as the vendor, because of (i) their familiarity with Big Rivers and its power plants, (ii) their ability and willingness to provide a depreciation study in accordance with Big

Rivers' required timeframe, and (iii) their competitive pricing relative to other respondents to the RFP.

Q. Why did Big Rivers select Burns & McDonnell to perform the depreciation study used in this filing, even though there were statements disclosed in discovery in the 2011 Rate Case to the effect that Big Rivers would not use them again?

A. Burns & McDonnell performed the depreciation study that was relied upon by Big Rivers in the 2011 Rate Case. The statement disclosed during discovery in the 2011 Rate Case about not using this vendor in the future was related to process issues that arose during the development and completion of the study, and which have since been resolved; the statement was not related to the final analysis or its conclusions. As Big Rivers fully explained in the 2011 Rate Case, Big Rivers was satisfied with the final study that was delivered, and the resulting depreciation rates were approved by both the RUS and the Commission.

Q. Has RUS approved the depreciation rates recommended by the study used in this filing?

A. Yes. On November 20, 2012, Big Rivers requested RUS approval to revise the depreciation rates as recommended in the study provided in the Direct Testimony of Mr. Ted J. Kelly as his Exhibit Kelly-1. RUS approved the rates in a letter dated December 27, 2012. The RUS approval letter is provided as Exhibit Richert-3.

VI. MAINTAINING COMPLIANCE WITH FINANCIAL OBLIGATIONS TO SUPPORT BIG RIVERS' FINANCIAL AND BUSINESS HEALTH

Q. What are the financial covenant obligations Big Rivers must meet?

A. Big Rivers has financial covenant obligations under all of its credit agreements. In this testimony, I will focus on some of the principal financial covenant obligations of Big Rivers under the following credit documents:

(i) Indenture dated as of July 1, 2009 (the "Indenture") between Big Rivers and U.S. Bank National Association, as trustee (the "Trustee");

(ii) Amended and Consolidated Loan Contract dated as of July 16, 2009 (the "RUS Loan Contract") between Big Rivers and the United States of America acting by and through the Administrator of the Rural Utilities Service ("RUS");

(iii) Revolving Line of Credit Agreement, dated as of July 16, 2009 (the "CFC Revolver") between Big Rivers and National Rural Utilities Cooperative Finance Corporation ("CFC");

(iv) Loan Agreement dated as of July 27, 2012 (the "CFC Secured Loan Agreement") between Big Rivers and CFC;

(v) $50,000,000 Senior Unsecured Revolving Credit Agreement dated as of July 27, 2012 (the "CoBank Revolver") among Big Rivers, the several lenders from time to time parties thereto and CoBank, ACB ("CoBank"), as administrative agent, issuing lender, lead arranger and book runner;

(vi) Secured Credit Agreement dated as of July 24, 2012 (the "CoBank Secured Loan Agreement") between Big Rivers, the several lenders from time to time parties thereto and CoBank, as administrative agent, issuing lender, lead arranger and book runner;

(vii) Loan Agreement dated as of June 1, 2010 between Big Rivers and the County of Ohio, Kentucky (the "County") relating to a loan in the amount of $83,300,000 evidenced by the First Mortgage Note, Series 2010A;

(viii) Loan Agreement dated as of June 1, 1983, as amended and supplemented (the "1983 Loan Agreement"), between Big Rivers and the County;

(ix) Reimbursement Agreement dated as of July 15, 1998 between Big Rivers and Ambac Assurance Corporation ("Ambac"); and

(x) Standby Bond Purchase Agreement ("Standby Bond Purchase Agreement") among Big Rivers, U.S. Bank National Association and Credit Suisse First Boston (subsequently assigned to Dexia Credit Local) dated July 17, 1998.

Q. Have these financing documents previously been filed with the Public Service Commission?

A. Yes. Exhibit Richert-4 attached to my testimony lists each of these documents and identifies the Commission proceeding in which it was filed with and approved by the Commission.

Q. Why are the obligations and financial covenants contained in those agreements relevant to this rate filing?

A. This rate case filing is driven by Big Rivers' need to increase its revenues to allow it to comply with these financial covenants through, among other things, meeting required minimum metrics, maintaining credit ratings and properly maintaining Big Rivers' utility plant. This in turn improves Big Rivers' ability to obtain access to the credit markets at reasonable interest rates.

Q. Will you summarize some of the principal obligations of Big Rivers under its credit agreements, and the consequences of Big Rivers failing to comply with those obligations?

A. Yes. Big Rivers must, of course, have sufficient revenue to pay its bills and debts as they become due. Big Rivers' failure to make a payment when due under any one of these credit agreements is a default.

Big Rivers must also maintain an MFIR of 1.10 to have the contractual ability to borrow money on a secured basis, and to avoid circumstances that could lead to a default under several of its credit agreements and an automatic increase in its borrowing costs. Failure to maintain MFIR or failure to maintain two investment grade credit ratings can result in RUS implementing a lockbox arrangement under which most of Big Rivers' revenues will go into a lockbox, and its obligations will be paid from the lockbox in accordance with the terms of the lockbox arrangement. Termination of a Smelter Agreement can also trigger the lockbox arrangement, and is currently an event of default under certain of Big Rivers' credit agreements, which I discuss in more detail below. There are cross-default provisions and other interrelationships between and among Big Rivers' credit agreements.

Also, it is important to keep in mind that, even though they are closely interwoven in the credit agreements, the obligations noted above are independent of one another. Failure to maintain MFIR, failure to maintain two investment grade credit ratings, and the termination of a Smelter Agreement are all independent criteria, which alone or in combination can create serious consequences for Big Rivers, as I discuss below.

Q. Will you please take us through each of the credit agreements you have identified, and describe some of the principal financial covenants Big Rivers has undertaken in it?

A. Yes. There are, of course, numerous financial covenants in Big Rivers' credit agreements. For purposes of this testimony, I will discuss some of the principal financial covenants Big Rivers has undertaken in its credit agreements.

Q. What financial covenants has Big Rivers undertaken in the Indenture?

A. Big Rivers is required by Section 13.14 of the Indenture to establish and collect rates that will enable Big Rivers to comply with all of its covenants under the Indenture. One of those covenants is that, subject to appropriate regulatory approvals, Big Rivers establish and collect rates that are reasonably expected to yield an MFIR for each fiscal year equal to at least 1.10. "Margins for Interest Ratio" is defined in the Indenture as, for any period, (i) the sum of (a) Margins for Interest plus (b) Interest Charges, divided by (ii) Interest Charges. Excerpts from relevant sections of the Indenture, including Section 13.14 and the definition of Margins for Interest Ratio, are attached to my testimony as Exhibit Richert-5.

Q. Will the rates proposed by Big Rivers produce revenues that will meet Big Rivers' revenue requirements, including enabling Big Rivers to comply with the minimum MFIR covenant in the Indenture?

A. In all likelihood, yes. The calculation of MFIR for the test year of September 1, 2013, through August 31, 2014, assuming the proposed rates are in effect, produces an MFIR of 1.20. That calculation is shown in attached Exhibit Richert-6. Based upon the information we have about the period immediately following the date on which the new rates are anticipated to go into effect – and noting, however, that there is very little room for contingencies -- Big Rivers can reasonably expect the proposed rates to produce at least a 1.10 MFIR for fiscal year 2013, even though the new rates will only be in effect for slightly more than four months during fiscal year 2013.

Q. What was Big Rivers' MFIR in fiscal year 2011?

A. Big Rivers' MFIR for fiscal year 2011 was 1.12 based upon margins of $5.6 million. Big Rivers attained its MFIR for that period by very carefully planning and executing its business strategies including taking extraordinary steps to lower its expenses as a result of lower prices for power in the wholesale market. A major part of the business strategy was corporate-wide cost-cutting and implementation of cost deferral measures, including postponing planned generating unit maintenance outages, transmission maintenance, and general and administrative discretionary expenses.

Q. What is the difference in margins that resulted in a MFIR of 1.12, rather than 1.10 for the fiscal year 2011?

A. Big Rivers' MFIR for fiscal year 2011 would have been 1.10 if its margins had been $4.6 or only $1.00 million less than they were. This is a very narrow margin of error, 0.2%, for a business with a 2011 annual cost of service of $557 million.

Q. What significance does Contract TIER have in the discussion of Big Rivers' finances?

A, Big Rivers effectively cannot earn more than a 1.24 Contract TIER. Under the terms of the Smelter Agreement TIER Adjustment mechanism and the rebate mechanism built into the Smelter Agreements and Big Rivers' tariffs to its members, revenue that would push Big Rivers' margins above a 1.24 Contract TIER is redirected to reduce the Smelter TIER Adjustment Charge, and if large enough and subject to certain approvals, to a rebate to all Members. It is interesting to note that the difference in margins required for Big Rivers to achieve a 1.10 MFIR in 2011 ($4.6 million), and the margins Big Rivers would have earned if it had achieved a 1.24 TIER ($11.0 million), is only $6.4 million, or 1.2%, of Big Rivers' 2011 cost of service.

Q. Does Big Rivers have its financial results for 2012?

A. No, but financial results for 2012 will be provided when they are final.

Q. What are the implications for Big Rivers of failing to comply with the MFIR covenant in the Indenture?

A. As mentioned above, subject to regulatory approvals, Big Rivers is required to always establish and collect rates that are reasonably expected to yield an MFIR of at least 1.10. If Big Rivers has complied with that covenant, but still fails to achieve the minimum required MFIR of 1.10 in a fiscal year, Big Rivers can avoid an Event of Default under the Indenture by immediately seeking rates that will comply with its covenants in the Indenture. A failure by Big Rivers to achieve the minimum MFIR, along with a failure to seek an immediate increase in rates, would constitute an Event of Default under the Indenture.

Q. Does this mean that there is no practical penalty under the Indenture for Big Rivers failing to achieve an MFIR of 1.10 in a fiscal year?

A. No. As also mentioned above, failure of Big Rivers to achieve a 1.10 MFIR can prohibit Big Rivers from borrowing money and securing it under the Indenture, even if that failure has not resulted in an Event of Default under the Indenture. More specifically, before Big Rivers can issue "Additional Obligations" secured by the Indenture, Big Rivers must deliver an Available Margins Certificate that the MFIR is not less than 1.10 for one of the periods of time described in the definition of Available Margins Certificate in Section 1.1 of the Indenture. This definition is shown on page one of Exhibit Richert-5.

Note that the description of MFIR noted above pertains to Big Rivers' covenants under the Indenture; however, achieving the minimum required MFIR of 1.10 in a fiscal year does not mean that such results are sufficient to attract capital in the financial markets. It is my understanding that G&Ts that borrow funds in the capital markets typically must earn margins and interest coverage ratios in excess of the minimum required MFIR stated in the credit agreements to obtain access to the financial markets, and to borrow capital at reasonable rates. My understanding is that the financial markets use data similar to that provided in Exhibit Richert-2 to evaluate a G&T's credit quality.

Q. Why would a limitation on Big Rivers' ability to secure additional obligations under the Indenture create a problem for Big Rivers?

A. Big Rivers must have the ability to borrow money on a long-term, secured basis. A utility the size of Big Rivers that operates generation and transmission facilities will always have periodic cash and borrowing requirements for both anticipated and unanticipated needs. The risk to Big Rivers resulting from an inability to borrow money on a long-term secured basis is one of the principal reasons Big Rivers pursued the Unwind Transaction.

More specifically, Big Rivers will have approximately $60,000,000 in pollution control equipment expenditures in 2013 and 2014. Big Rivers expects initially to finance these expenditures with a new short-term loan from CFC, and then convert that short-term borrowing to long-term financing with RUS. The long-term financing with RUS and the interim bridge financing with CFC must be secured under the Indenture. These mandatory pollution control facilities must be installed on Big Rivers' generating units by April 2015 for Big Rivers to be in compliance with the Mercury and Air Toxics Standards ("MATS") rule and continue operating its generating facilities after that date. If Big Rivers fails to achieve a MFIR of 1.10, it will lose the right to secure debt under the Indenture until

Big Rivers can give the Indenture Trustee the certification required by the Available Margins Certificate, as stated in Section 1.1 of the Indenture, an excerpt of which is found on page 1 of my attached Exhibit Richert-5.

Q. Do you believe Big Rivers' future financing may be in jeopardy as a result of the contract termination by Century Aluminum?

A. Yes. I am deeply concerned that without the requested increase in rates, Moody's, S&P, and Fitch rating services will downgrade Big Rivers' credit ratings, which would severely restrict our ability to attract capital, not to mention the adverse impact on the interest rates at which capital might be available.

Q. Would you explain this risk further?

A. Big Rivers has a debt rating of Baa2 from Moody's and a rating of BBB– from both S&P and Fitch. In addition to these ratings each agency has also assigned a rating outlook of "negative." This separate designation provides the agency's view as to the direction of the rating. "Negative" generally means the agencies may downgrade the letter rating. Since Big Rivers is already at the lowest level in the "BBB" (a category of "BBB-"), a downgrade by Standard & Poor's or Fitch would result in a rating in the "BB" range. The "BB" range is below investment grade. I am not aware of any other G&T cooperative that has financed in the capital markets with a rating in the "BB" range.

Q. Have the rating agencies indicated that a downgrade is possible?

A. Yes. Each of the agencies has clearly stated in its report in Exhibit Richert-7 that a downgrade is on the radar screen. This is evident from the following excerpts from their most recent reports:

Moody's Credit Opinion - August 22, 2012

> What could change the Rating - Down
>
> Loss of significant load due to Century's announcement that is not otherwise compensated for through off system power rates or other measures could contribute to a negative action, as would the inability to secure needed rate increases from the non-smelter member load.

S&P Report - August 31, 2012

> The negative outlook reflects our vision that the largest customer's decision to close facilities after failing to win rate concessions could degrade BREC's financial performance and credit quality during our two year outlook horizon.

Fitch Rating Report - August 31, 2012

> What Could Trigger A Rating Action
>
> Insufficient Regulatory Support: Inadequate or untimely support by the Kentucky Public Service Commission (KPSC) would be viewed negatively.

Big Rivers' future credit ratings will clearly be determined by the outcome of this rate case, and the timeliness and level of regulatory support.

Q. What financial covenants has Big Rivers undertaken in the RUS Loan Contract?

A. The RUS Loan Contract requires Big Rivers to comply with the financial covenants in the Indenture. It also requires in Section 4.23(a) that Big Rivers maintain an investment grade credit rating from at least two rating agencies. Big Rivers currently complies with the latter requirement although, as stated above, Moody's has recently downgraded Big Rivers by one notch to Baa2, which is one notch above minimum investment grade, and all three ratings agencies have placed Big Rivers on negative watch.

If Big Rivers fails to maintain an investment grade credit rating from at least two rating agencies, Big Rivers must implement a corrective plan satisfactory to RUS, or it is an Event of Default. The RUS Administrator may also impose a lockbox arrangement on Big Rivers' receipts and disbursements under Section 4.12 of the RUS Loan Contract, whether or not there is an Event of Default. A corrective plan to improve Big Rivers' credit ratings would almost certainly include a rate case to increase Big Rivers' revenues and improve its financial condition. Relevant excerpts from the RUS Loan Contract, including Section 4.12, are included in Exhibit Richert-5.

Big Rivers will have to determine whether termination of the Century retail and wholesale contracts on August 20, 2013, will have a Material Adverse Effect under Section 4.09(f) of the RUS Loan Agreement, and if so, report that fact to RUS. Either that report or an accumulation of factors could cause RUS to request the Section 4.12 lockbox arrangement.

Q. What financial covenants has Big Rivers undertaken in the $50 million CFC Revolver?

A. Big Rivers is required to achieve and maintain a MFIR of no less than 1.10 (Sections 5.01G and 6.01) and an equity ratio of no less than 12%. The CFC Revolver expires July 15, 2014.

Q. What are the implications for Big Rivers of failing to comply with its financial covenants in the $50 million CFC Revolver?

A. Big Rivers is required <u>to achieve and maintain</u> an MFIR of no less than 1.10 under the CFC Revolver. This rate covenant is different than the covenant in the Indenture. For purposes of the Indenture test, Big Rivers must set rates "reasonably expected to yield," whereas the covenant in this CFC Revolver is a failure to "achieve and maintain." To avoid a violation of this covenant, Big Rivers' rates must yield an MFIR of no less than 1.10.

If Big Rivers fails to comply with the rate covenant contained in the CFC Revolver, it is a covenant event of default under the CFC Revolver, Section 9.03, and CFC may terminate the line of credit, cease issuing letters of credit, and accelerate the loans and all amounts owing by Big Rivers under that agreement. The default rate adds two percent (2%) to the interest rate.

It is an event of default under the CFC Revolver, Section 6.01 M, if Big Rivers' wholesale electric service agreement with Kenergy for service to Century terminates, which it will on August 20, 2013. If this contract term is not changed, Big Rivers will be unable to borrow under the CFC Revolver after that date. Big Rivers is currently having discussions with CFC about this issue.

Q. What financial covenants has Big Rivers undertaken in the $302 million CFC Secured Loan Agreement?

A. The CFC Secured Loan Agreement requires that Big Rivers comply, in all respects, with the MFIR covenant set forth in the Indenture.

Q. What are the implications for Big Rivers of failing to comply with its financial covenant in the $302 million CFC Secured Loan Agreement?

A. The CFC Secured Loan Agreement (Section 6.01 C) states that failure to comply with Section 13.14 of the Indenture is an event of default under the agreement. Upon the occurrence of an Event of Default, CFC may exercise several rights, including all rights and remedies available to CFC as a holder of an obligation under the Indenture. In addition, an interest rate adder of two percent (2%) will be imposed on the outstanding principal amount of all advances until the event of default is cured.

Q. What financial covenants has Big Rivers undertaken in the $50 million CoBank Revolver?

A. Under the terms of the CoBank Revolver, Big Rivers must maintain a minimum MFIR of at least 1.10 for any fiscal year (Section 8.01), and a Total Debt to Capitalization Ratio of not greater than 0.80:1.00 as of the last day of each fiscal year (Section 8.02). The CoBank Revolver expires on July 27, 2017.

Q. What are the implications for Big Rivers of failing to comply with its covenants in the $50 million CoBank Revolver?

A. If Big Rivers fails to comply with either of these financial covenants it is an event of default under the CoBank Revolver (Section 9.03), and CoBank may terminate any lending commitments and obligations to make letter of credit extensions, and accelerate the loans and all amounts owing by Big Rivers under the CoBank Revolver. The default rate adds two percent (2%) to the interest rate. In addition, the interest rate paid by Big Rivers on the unpaid principal balance of loans under the CoBank Revolver is either (i) the London Interbank Offered Rate ("LIBOR") plus a LIBOR margin or (ii) the Base Rate plus a Base Rate margin. The margins are tied to Big Rivers' credit ratings; the better the rating, the lower the margin. Big Rivers' credit ratings and borrowing margin would certainly suffer if it defaulted under the CoBank Revolver.

As a result of the Century termination notice, Big Rivers is unable to borrow under the CoBank Revolver. Termination of the Century retail agreement is an event of default under the CoBank Revolver, Section 9.09

that will result in the same remedies previously mentioned for an event of default under the CoBank Revolver. Big Rivers is currently having discussions with CoBank about these issues.

Q. What financial covenants has Big Rivers undertaken in the $235 million CoBank Secured Loan Agreement?

A. The CoBank Secured Loan Agreement has a financial covenant that Big Rivers comply with Section 13.14 of the Indenture (Article 8).

Q. What are the implications for Big Rivers of failing to comply with its covenants in the $235 million CoBank Secured Credit Agreement?

A. If Big Rivers defaults in the observance or performance of the financial covenant, there is an event of default under this agreement (Section 9.03). If an event of default under this agreement is also an event of default under the Indenture, the lenders have the rights and remedies of the holders of obligations under the Indenture. Failure to comply with the rate covenant would be an event of default under the Indenture. In addition, the loan may be accelerated as provided in, and subject to the terms of the Indenture. The default rate under the agreement is the interest rate of the loan plus two percent (2%). Lastly, it is an event of default under the CoBank Secured Credit Agreement if, with respect to any indebtedness owed to CoBank, which would include amounts under the CoBank Revolver, that indebtedness is accelerated or if CoBank's commitment to lend under the CoBank Revolver is terminated as a result of a default. As I have already noted, Big Rivers is in discussions with CoBank about this issue.

Q. Are there other negative implications for Big Rivers if it fails to comply with the financial covenants under the Indenture and the RUS Loan Contract?

A. Yes. Big Rivers relies on the two $50 million revolving credit agreements with CoBank and CFC to supplement its liquidity needs required in its normal business operations, including but not limited to, the issuance of standing letters of credits required by the Midwest Independent Transmission System Operator, Inc. ("MISO"), by counterparties with whom Big Rivers executes wholesale power transactions, and by fuel suppliers. In addition, these two revolving credit agreements provide Big Rivers the ability to comply with cash balance requirements as defined by the Big Rivers Financial Policy. Access to funds under these agreements, and Big Rivers' ability to renew these agreements after they expire in 2014 and 2017, respectively, could be adversely affected by Big Rivers failing to comply with its financial covenants under the Indenture and the RUS Loan Contract. Maintaining these revolving credit agreements is very important to Big Rivers, to the credit rating agencies and to Big Rivers' creditors generally because of the significant liquidity they provide.

Q. What is the policy of Big Rivers with respect to compliance with the financial covenants of its loan agreements?

A. Big Rivers' policy is to be in full compliance with the financial covenants of its loan agreements, and it believes that any other policy would be imprudent.

VII. IMPLICATION OF CENTURY TERMINATION NOTICE ON BIG RIVERS' FINANCIAL OBLIGATIONS

Q. What are the implications of the Century contract termination notice on Big Rivers' rights and obligations under the credit agreements you have listed?

A. As discussed above, Big Rivers is unable to take advances under the CoBank Revolver as a result of the receipt of the Century termination notice. The Century termination notice has also had an impact on Big Rivers' credit ratings, the extent and significance of which I have discussed earlier in my testimony.

Q. What will be the implications of the Century contract termination on Big Rivers' rights and obligations under the credit agreements you have listed?

A. The actual termination of the Century retail agreement on August 20, 2013, and the concurrent termination of the Big Rivers wholesale agreement with Kenergy that is tied to the Century retail agreement, will have negative implications under the credit agreements in addition to what I have already discussed in my testimony. Section 4.09(f) of the RUS Loan Contract requires that Big Rivers give notice to RUS of any matter that has had or could reasonably be expected to have a "Material Adverse Effect." For Big Rivers to determine if an action could have a Material Adverse Effect, it needs to examine the potential consequences of any such action. This is not only an examination of whether or not Big Rivers can pay its debts, but also the effect of the contract termination on the outcome of the rate case to replace the Century revenue loss, Big Rivers' ability to meet its financial covenants so that it can still issue secured debt, Big Rivers' access to its lines of credit, and Big Rivers' ability to maintain its investment grade ratings. All of these factors need to be considered. Even if Big Rivers does not conclude that the Century termination will have a Material Adverse Effect, the termination of the Century contract may result in an accumulation of factors that causes the Administrator of the RUS to request the lockbox arrangement.

Q. Could these direct consequences under Big Rivers' credit agreements that flow from failure to comply with financial covenants and the actual termination of the Century retail and wholesale agreements on August 20, 2013, have any indirect impacts on Big Rivers' other credit agreements?

A. Yes. The existence of an event of default, combined with an acceleration of the debt under certain of the credit agreements as discussed above, also could have an impact on the other agreements resulting in cross defaults. Another indirect impact of Century's notice and the pending termination of both the Century retail and wholesale agreements is the negative impact on Big Rivers' ability to refinance the 1983 Bonds. The 1983 Bonds mature on June 1, 2013, so Big Rivers needs to sell obligations to refund the 1983 Bonds. If Big Rivers fails to pay the 1983 Bonds on or before the maturity date, Big Rivers will default under the terms of the Dexia Note and the 1983 Note. Default under the Dexia Note would become a default under Big Rivers' Indenture which, if not remedied, would result in a default on all of Big Rivers' Indenture debt. Big Rivers is presently seeking authority from the Commission to refinance those bonds in Case No. 2012-00492.

VIII. <u>RESERVE FUNDS</u>

Q. Did Big Rivers examine the possible use of any of its three reserve accounts that were created as part of the Unwind Transaction for mitigating the impact of the proposed rate increase on member billings?

A. Yes.

Q. Please describe the reserve accounts.

A. As a result of the Unwind Transaction, Big Rivers established three reserves, (1) an economic reserve with an initial principal amount equal to $157 million (the "Economic Reserve"), (2) a second economic reserve with an initial principal amount equal to $60.9 million (the "Rural Economic Reserve"), and (3) a transition reserve with an initial principal amount equal to $35 million (the "Transition Reserve"). The Economic Reserve was established to help Big Rivers cushion the effect of future rate increases for fuel and environmental expenses on its rates to its Rural Delivery Service and Large Industrial Customer rate classes. The Rural Economic Reserve account was established to help Big Rivers cushion the effect of future rate increases for fuel and environmental expenses on its rates to its Rural class only, upon exhaustion of the Economic Reserve. The Transition Reserve account was established as a "Special Funds" account to mitigate Big Rivers' need for cash associated with a Smelter terminating its power contract. The transition reserve was envisioned to provide assurance to Big Rivers' creditors and the rating agencies that Big Rivers had additional liquidity protection, should one or both Smelters cease operations.

Q. How did Big Rivers initially fund the Transition Reserve?

A. Big Rivers initially funded the Transition Reserve with $35 million from the consideration it received from E.ON U.S., LLC at the Unwind Transaction closing.

Q. What is the current balance in the Transition Reserve?

A. As of November 30, 2012, the balance in the Transition Reserve was $35,021,574.

Q. Could Big Rivers use the Transition Reserve to help Big Rivers achieve its annual MFIR, as a result of Century's contract termination?

A. No. The Transition Reserve only provides an additional source of liquidity to Big Rivers should it experience a cash shortage as a result of the termination of a Smelter Agreement. Use of the Transition Reserve funds would not aid Big Rivers in achieving its annual MFIR requirement with its lenders. The Transition Reserve funds were recognized as income at the closing of the Unwind Transaction. Accordingly, use of the Transition Reserve funds would not offset any decreases in revenues or increases in expenses on Big Rivers' statement of operations; thus it cannot assist Big Rivers in achieving its annual MFIR requirements.

Q. How does Big Rivers propose to use the Economic Reserve and Rural Economic Reserve in this case?

A. Big Rivers does not propose any changes to the use of the Economic Reserve and Rural Economic Reserve at this time. These accounts will continue to be used to cushion the effect of future rate increases for fuel and environmental expenses on Big Rivers' rates to the members for service to their non-Smelter customers (for the Economic Reserve) and their Rural customers (for the Rural Economic Reserve).

IX. FILING REQUIREMENTS

Q. Have you reviewed the answers provided in Tabs 1-62, which address Big Rivers' compliance with the filing requirements under 807 KAR 5:001 and its various subsections?

A. Yes. I hereby incorporate and adopt those portions of Tabs 1-62 for which I am identified as the sponsoring witness.

X. CONCLUSION

Q. What are your conclusions and recommendations to the Commission in this proceeding?

A. Big Rivers is in a very precarious and urgent situation with respect to its financial condition. The Century contract termination notice and the $74.5 million revenue deficiency described in this filing put Big Rivers in a position that, without rate relief, it will be unable to attract capital and to meet its debt covenant obligations, and it faces potential default on its credit agreements. Big Rivers does not take lightly the decision to seek this increase; however, this base rate increase is absolutely required.

The fully forecasted test period is based on Big Rivers' 2013 and 2014 budgets that are reasonable, that result from the process Big Rivers routinely follows for budgeting and that were approved by Big Rivers' Board of Directors. The rates proposed herein are fair, just and reasonable and should be approved by the Commission.

Q. Does this conclude your testimony?

A. Yes.

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2012-00535

VERIFICATION

I, Billie J. Richert, verify, state, and affirm that I prepared or supervised the preparation of my testimony filed with this Verification, and that testimony is true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Billie J. Richert

Billie J. Richert

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Billie J. Richert on this the 9th day of January, 2013.

Paula Mitchell

Notary Public, Ky. State at Large
My Commission Expires 1-12-17

Professional Summary

Billie J. Richert, CPA, CITP
Vice President, Accounting and Interim Chief Financial Officer
Big Rivers Electric Corporation
201 3rd Street
Henderson, Kentucky 42420
(270) 844-6190

Professional Experience

Big Rivers Electric Corporation 2010 to present

Vice President, Vice President Accounting and Interim CFO

Manager, Business Systems Infrastructure

Oracle Accounting System Administrator

DePauw University 2006 - 2009

Director of Financial Systems

REL-TEK Systems & Design, Inc. 1982 - 1999

President, CEO and founder

Landau and Bartelstein CPAs 1978 - 1982

Senior Staff Accountant and Business Consultant

Deloitte LLP (formerly Haskins & Sells) 1973 – 1977

Senior Tax Accountant
Auditor

Certifications

Licensed Certified Public Accountant (CPA)
Certified Information Technology Professional (CITP)

Education

Master of Management, Finance, 1982

Northwestern University J. L. Kellogg Graduate School of Management

Bachelor of Science, Accounting 1973

Indiana University

Big Rivers Electric Cooperation
Case No. 2012-00535
G&T TIER and MFI Analysis for 2011

	Moodys	Fitch	S&P	TIER or MFI
Golden Spread	NR	A	**A(Stable)**	3.17
Arkansas	A1	A+	**AA-(Stable)**	2.37
Central Iowa	NR	A	**A(Stable)**	2.18
Brazos	NR	A	**A-(Positive)**	1.95
Corn Belt	NR	A-	**A-(Stable)**	1.88
Hoosier	A3	NR	**A(Stable)**	1.83
South Miss.	NR	A-	**A-(Stable)**	1.72
South Texas	NR	A-	**A-(Stable)**	1.70
San Miguel	NR	A-	**A-(Stable)**	1.57
Buckeye	A2	A	**A-(Stable)**	1.50
Associated	A1	AA	**AA(Stable)**	1.49
East Kentucky	NR	BBB	**BBB(Stable)**	1.48
Wabash Valley	NR	NR	**A-(Stable)**	1.47
Power South	NR	A-	**A-(Stable)**	1.44
Dairyland	A3	NR	**A(Stable)**	1.43
Minnkota	NR	NR	**A-(Stable)**	1.43
Seminole	NR	NR	**A-(Stable)**	1.41
Central-SC	NR	NR	**AA-(Stable)**	1.40
Chugach	NR	A-	**A-(Stable)**	1.30
Western Farmers	NR	A-	**BBB+(Positive)**	1.29
North Carolina	NR	A-	**A-(Stable)**	1.29
Basin	A1	A+	**A(Stable)**	1.26
Great River	Baa1	A-	**A-(Stable)**	1.22
Old Dominion	A3	A	**A(Stable)**	1.22
Oglethorpe	Baa1	A	**A(Stable)**	1.14
Average				**1.61**
Big Rivers	**Baa2(Neg)**	**BBB-(Neg)**	**BBB-(Neg)**	**1.12**

NR: No Rating

Source: G&T Accounting & Finance Association Annual Directory June 2012, Fitch U.S. Public Power Peer Study June 2012, S&P Report Card: Rate Adjustments Compensate For U.S. Cooperative Utilities Regulatory and Economic Risks May 22, 2012

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

Big Rivers Electric Corporation
Case No. 2012-00535
Cross-references to PSC Cases in which Financing Documents are Filed

(i) Indenture dated as of July 1, 2009, between Big Rivers and U.S. Bank National Association, as trustee; as rendered *In the Matter of the Applications of Big Rivers Electric Corporation, E.On U.S., LLC, Western Kentucky Energy Corp. and LG&E Energy Marketing,* P.S.C. Case No. 2007-00455;

(ii) Amended and Consolidated Loan Contract dated as of July 16, 2009, between Big Rivers and the United States of America acting by and through the Administrator of the Rural Utilities Service, as rendered *In the Matter of the Applications of Big Rivers Electric Corporation, E.On U.S., LLC, Western Kentucky Energy Corp. and LG&E Energy Marketing,* P.S.C. Case No. 2007-00455;

(iii) Revolving Line of Credit Agreement, dated as of July 16, 2009, between Big Rivers and National Rural Utilities Cooperative Finance Corporation, as rendered *In the Matter of the Applications of Big Rivers Electric Corporation, E.On U.S., LLC, Western Kentucky Energy Corp. and LG&E Energy Marketing,* P.S.C. Case No. 2007-00455;

(iv) Loan Agreement Dated as of July 27, 2012, between Big Rivers and National Rural Utilities Cooperative Finance Corporation as an enclosure in letter dated August 3, 2012, to PSC in the matter of *Application of Big Rivers Electric Corporation for Approval to Issue Evidences of Indebtedness,* P.S.C. Case No. 2012-00119;

(v) Note for $50,000,000 Senior Unsecured Revolving Credit Agreement dated as of July 27, 2012, among Big Rivers, lenders, and CoBank, ACB, as administrative agent, issuing lender, lead arranger and book runner as an enclosure in letter dated August 3, 2012, to PSC in the matter of *Application of Big Rivers Electric Corporation for Approval to Issue Evidences of Indebtedness,* P.S.C. Case No. 2012-00119;

(vi) Secured Credit Agreement dated as of July 24, 2012, between Big Rivers, the several lenders from time to time parties thereto and CoBank, as administrative agent, issuing lender, lead arranger and book runner as an enclosure in letter dated August 3, 2012, to PSC in the matter of *Application of Big Rivers Electric Corporation for Approval to Issue Evidences of Indebtedness,* P.S.C. Case No. 2012-00119;

(vii) Loan Agreement dated as of June 1, 2010, between Big Rivers and the County of Ohio, Kentucky relating to a loan in the amount of $83,300,000 evidenced by the First Mortgage Note, Series 2010A, *Application of Big Rivers Electric Corporation for Approval to Issue Evidences of Indebtedness,* P.S.C. Case No. 2009-00441;

(viii) Loan Agreement dated as of June 1, 1983, as amended and supplemented, between Big Rivers and the County, *Application of Big Rivers Electric Corporation,* P.S.C. Case No. 7990;

(ix) Reimbursement Agreement dated as of July 15, 1998, between Big Rivers and Ambac Assurance Corporation, *The Application of Big Rivers Electric Corporation for Approval of the 1998 Amendments to Station Two contracts Between Big Rivers Electric Corporation and the City of Henderson, Kentucky and the Utility Commission of the City of Henderson,* P.S.C. Case No. 98-267;

and

(x) Standby Bond Purchase Agreement among Big Rivers, U.S. Bank National Association and Credit Suisse First Boston (subsequently assigned to Dexia Credit Local) dated July 17, 1998 (as amended by P.S.C. Order dated August 25, 2000), *Big Rivers Electric Corporation's Application for Approval of Amendments to Standby Bond Purchase Agreements,* P.S.C. Case No. 2000-343.

Excerpts from: Indenture Dated as of July 1, 2009, between Big Rivers Electric Corporation and U.S. Bank National Association, Trustee

Section 1.1 Definitions.

"**Available Margins Certificate**" means an Officers' Certificate, dated not more than thirty (30) days prior to the date of the related Application, and signed by a Person who is an Accountant (who may be one of the two signing Officers), stating that:

A. the Margins for Interest Ratio is not less than 1.10 for one of the following periods of time: (i) the fiscal year of the Company immediately preceding the fiscal year in which the Application is made, or (ii) if the Application is made within ninety (90) days after the end of a fiscal year, the second preceding fiscal year of the Company or (iii) any twelve (12) consecutive calendar months during the period of fifteen (15) calendar months immediately preceding the first day of the calendar month in which the Application is made **PROVIDED, HOWEVER**, that if any such period of time is one in which this Indenture has not been in effect for the full period of time, then, in lieu of a statement as to the Margins for Interest Ratio, such Available Margins Certificate shall state that the Times Interest Earned Ratio (as defined in the Existing Mortgage) is not less than 1.05 for such period of time; and

B. the Margins for Interest Ratio has been calculated in accordance with the definitions contained in this Indenture **PROVIDED, HOWEVER**, that if the Available Margins Certificate makes a statement as to the Times Interest Earned Ratio and not the Margins for Interest Ratio, stating that the Times Interest Earned Ratio has been calculated in accordance with the provisions of the Existing Mortgage.

If any period of twelve (12) months referred to in an Available Margins Certificate has been a period with respect to which an annual report is required to be filed by the Company pursuant to Section 10.4, such Certificate shall be accompanied by a report of an Independent Accountant stating in substance that nothing came to the attention of such Accountant in connection with the audit of such period that would lead such Accountant to believe that there was any incorrect or inaccurate statement in such Available Margins Certificate; **PROVIDED, HOWEVER,** that if the Application is made prior to the date on which an annual report is required to be filed by the Company pursuant to Section 10.4, such Certificate shall not be accompanied by such Independent Accountant's report. Each such report of an Independent Accountant shall include the statement as to independence required by the definition of the term "Independent."

"**Interest Charges**" for any period means the total interest charges (whether capitalized or expensed) for such period (determined in accordance with Accounting Requirements) related to (i) Outstanding Secured Obligations of the Company, or (ii) outstanding Prior Lien Obligations of the Company, in all cases including amortization of debt discount and premium on issuance, but excluding all interest charges related to Obligations that have actually been paid by another Person that has agreed to be primarily liable for such Obligation pursuant to an assumption agreement or similar undertaking, provided such assumption agreement or similar undertaking is not a mechanism by which the Company continues to make payments to such Person based on payments made by such Person on account of its assumed liability or by which the Company otherwise seeks to avoid having interest related to such Obligations included in the definition of Interest Charges without the economic substance of an assumption of liability on the part of such Person; **PROVIDED, HOWEVER,** that with respect to any calculation of Interest Charges for any period prior to the date hereof, "Interest Charges" means the total interest charges (whether capitalized or expensed of the Company for such period (determined in accordance with Accounting Requirements) with respect to interest related to indebtedness the obligation for the payment of which was secured under the Existing Mortgage or by a lien against property subject to the Existing Mortgage prior to or on a parity with the lien of the Existing Mortgage, other than "Permitted Encumbrances" (as defined in the Existing Mortgage), in all cases including amortization of debt discount and premium on issuance.

. . .

"**Margins for Interest**" means, for any period, the sum of (i) net margins of the Company for such period (which, except as otherwise provided in this definition, shall be determined in accordance with Accounting Requirements), which shall include revenues of the Company, subject to possible refund at a future date, but which shall exclude provisions for any (a) non-recurring charge to income, whether or not recorded as such on the Company's books, of whatever kind or nature (including the non-recoverability of assets or expenses), except to the extent the Board of Directors determines to recover such non-recurring charge in Rates, (b) refund of revenues collected or accrued by the Company in any prior year subject to possible refund; plus (ii) the amount, if any, included in the computation of net margins for accruals for federal and state income and other taxes imposed on income after deduction of interest expense for such period; plus (iii) the amount, if any, included in the computation of net margins for any losses incurred by any Subsidiary or Affiliate of the Company; plus (iv) the amount, if any, the Company actually receives in such period as a dividend or other distribution of earnings or profits of any Subsidiary or Affiliate (whether or not such earnings were for such period or any earlier period or periods); minus (vi) the amount, if any, included in the computation of net margins for any earnings or profits of any Subsidiary or Affiliate of the Company; and minus (vi) the amount, if any, the Company actually contributes to the capital of, or actually pays under a guarantee by the Company of an obligation of, any Subsidiary or Affiliate in such period to the extent of any accumulated losses incurred by such Subsidiary or Affiliate (whether or not such losses were for such period or any earlier period or periods), but only to the extent such losses have not otherwise caused other contributions or guarantee payments to be included in net margins for purposes of computing Margins for Interest for a prior period and such amount has not otherwise been included in net margins.

"**Margins for Interest Ratio**" means, for any period, (i) the sum of (a) Margins For Interest plus (b) Interest Charges, divided by (ii) Interest Charges.

Section 8.1 Events of Default.

"**Event of Default**" means, wherever used herein, any one of the following events (whatever the reason for such event and whether it shall be voluntary or involuntary or be effected by operation of law or pursuant to any judgment, decree or order of any court or any order, rule or regulation of any administrative or governmental body).

. . .

C. default in the performance, or breach, of any covenant or warranty of the Company in this Indenture (other than a covenant or warranty a default in the performance or breach of which is described in paragraph A or B of this Section), and continuance of such default or breach for a period of thirty (30) days after there has been given, by registered or certified mail, to the Company by the Trustee, or to the Company and the Trustee by the Holders of not less than 25% in principal amount of the Obligations Outstanding, a written notice specifying such default or breach and requiring it to be remedied and stating that such notice is a "Notice of Default" hereunder, unless such default cannot be reasonably cured within such thirty (30) day period then, so long as a cure is being diligently pursued, the

Company shall have a reasonable period of time beyond such thirty (30) day period to complete such cure.

Section 13.1 Payment of Principal, Premium and Interest.

The Company will duly and punctually pay the principal of (and premium, if any) and interest on the Obligations in accordance with the terms of the Obligations and this Indenture.

Section 13.7 Maintenance of Properties.

The Company will cause all its properties used or useful in the conduct of its business to be maintained and kept in good condition, repair and working order and supplied with all necessary equipment and will cause to be made all necessary repairs, renewals, replacements, betterments and improvements thereof, all as in the judgment of the Company may be necessary so that the business carried on in connection therewith may be properly and advantageously conducted at all times; **PROVIDED, HOWEVER,** that nothing in this Section shall prevent the Company from discontinuing the operation and maintenance of any of its properties if such discontinuance is, in the judgment of the Company, desirable in the conduct of its business and not disadvantageous in any material respect to the Holders.

The Company will promptly classify, and record on its books, as retired, all property that has permanently ceased to be used or useful in the business of the Company.

Section 13.12 Statement as to Compliance.

The Company will deliver to the Trustee, within one hundred and twenty (120) days after the end of each calendar year beginning with the year 2010, a written statement signed by the principal executive officer and by the principal financial officer or principal accounting officer of the Company stating that a review of the Company's activities during the preceding calendar year has been made under their supervision and that the Company has fulfilled its obligations hereunder in all material respects during such calendar year.

Promptly after any Officer of the Company may reasonably be deemed to have knowledge of a default hereunder, the Company will deliver to the Trustee a written notice specifying the nature and period of existence thereof and the action the Company is taking and proposes to take with respect thereto.

Section 13.14 Rate Covenant.

The Company shall establish and collect rates, rents, charges, fees and other compensation (collectively, "**Rates**") that, together with other moneys available to the Company, produce moneys sufficient to enable the Company to comply with all its covenants under this Indenture. Subject to any necessary regulatory approval or determination and the approval of the RUS, if required, the Company also shall establish and collect Rates that, together with other revenues available to the Company, are reasonably expected to yield a Margins for Interest Ratio for each fiscal year of the Company equal to at least 1.10 for such period. Promptly upon any material change in the circumstances which were contemplated at the time such Rates were most recently reviewed, but not less frequently than once every twelve (12) months, the Company shall review the Rates so established and shall promptly establish or revise such Rates as necessary to comply with the foregoing requirements; subject in the case of the foregoing Margins for Interest requirement to any necessary regulatory approval or determination and the approval of the RUS, if required. The Company will not furnish or supply or cause to be furnished or supplied any use, output, capacity or service of the System with respect to which a charge is regularly or customarily made, free of charge to any Person, and the Company will use commercially reasonable efforts to enforce the payment of any and all accounts owing to the Company with respect to the use, output, capacity or service of the System.

Excerpts from: Amended and Consolidated Loan Contract dated as of July 16, 2009, between Big Rivers Electric Corporation and United States of America

Section 4.2 Performance under Loan Documents

The Borrower shall duly observe and perform all of its obligations under each of the Loan Documents.

Section 4.3 Annual Certification

Within ninety (90) days after the close of each fiscal year (or, if the Borrower has delivered written notice to the RUS prior to the expiration of such ninety (90) day period that the Borrower has determined in good faith that an additional thirty

(30) days for such delivery is necessary or advisable, then within one hundred twenty (120) days after the close of the fiscal year with respect to which such notice has been delivered), the Borrower shall deliver to the RUS a written statement signed by its General Manager, stating that during such year the Borrower has fulfilled its obligations under the Loan Documents throughout such year in all material respects or, if there has been a material default in the fulfillment of such obligations, specifying each such default known to the General Manager and the nature and status thereof.

Section 4.4 Rates and Margins for Interest Ratios

(a) *Prospective Requirement.* The Borrower shall design and implement rates for utility service furnished by it to maintain, on an annual basis, the Margins for Interest Ratio specified in Section 13.14 of the Indenture.

(b) *Prospective Notice of Change in Rates.* The Borrower shall give the RUS sixty (60) days' written notice prior to the effective date of any proposed change in the Borrower's general rate structure.

(c) *Routine Reporting of Margins for Interest Ratio.* The Borrower shall report to the RUS, no later than 45 days after December 31 of each year, in such written format as the RUS may require, the Margins for Interest Ratio that was achieved during the preceding 12-month period ending on December 31 of such year.

(d) *Reporting Non-achievement of Retrospective Requirement.* If the Borrower fails to achieve the Margins for Interest Ratio specified in Section 13.14 of the Indenture for any fiscal year, it must promptly notify RUS in writing to that effect.

(e) *Corrective Plans.* Within thirty (30) days of (i) sending a notice to the RUS under paragraph (d) above that shows the Margins for Interest Ratio specified by Section 13.14 of the Indenture was not achieved for any fiscal year, or (ii) being notified by the RUS that the Margins for Interest Ratio specified by Section 13.14 of the Indenture was not achieved for any fiscal year, whichever is earlier, the Borrower in consultation with the RUS shall provide a written plan satisfactory to the RUS setting forth the actions that shall be taken to achieve the specified Margins for Interest Ratio on a timely basis.

(f) *Noncompliance.* Failure to design and implement rates pursuant to paragraph (a) of this section and failure to develop and implement the plan in accordance with the terms of paragraph (e) of this section shall constitute an Event of Default under this Agreement in the event that RUS so notifies the Borrower to that effect under Section 6.1(d) of this Agreement.

Section 4.12 Separate Accounts

The Borrower shall execute and deliver, with a financial institution approved by the RUS, a lockbox agreement or agreements substantially in the form of Exhibit A attached hereto ("Lockbox Agreement") and shall at all times maintain such Lockbox Agreement in full force and effect. The Borrower shall not, without first complying with the requirements of Section 8.1, amend, supplement or otherwise modify the Lockbox Agreement. In the event: (a) the Borrower no longer has two Investment Grade credit ratings from at least two Rating Agencies; (b) the Borrower's total current and accrued liabilities exceed the Borrower's total current and accrued assets; (c) the Administrator determines the System is incapable of providing reliable service to the members of the Borrower pursuant to the terms of the Wholesale Power contracts; (d) the Administrator determines that as a consequence of any change in the condition, financial or otherwise, operations, properties or business of the Borrower, the Borrower will be unable to perform its material obligations under (i) this Agreement, (ii) the wholesale Power Contracts, (iii) the RUS Notes, or (iv) the Indenture; or (e) there is an Event of Default under the Indenture, or any event that with the passage of time or giving of notice, or both, would constitute an Event of Default under the Indenture, the Borrower shall, if so directed in writing by the Administrator of the RUS, (a) deposit, pursuant to the Lockbox Agreement, all cash proceeds of the Trust Estate, including, without limitation, checks, money and the like (other than cash proceeds deposited or required to be deposited with the Trustee pursuant to the Indenture), which cash proceeds shall include, without limitation, all payments by members of the Borrower on account of the Wholesale Power Contracts, in separate deposit or other accounts, segregated from all other monies, revenues and investments of the Borrower, and accounts, segregated from all other monies, revenues and investments of the Borrower, and (b) take all such other actions as the RUS shall request to continue perfection of the lien of the Indenture in such proceeds for the benefit of all Holders of the Outstanding Secured Obligations.

Section 4.13 Property Maintenance

The Borrower shall maintain and preserve its System in compliance in all material respects with the provisions of the Indenture, RUS Regulations, all applicable Laws, and Prudent Utility Practice.

Section 4.23 Maintenance of Credit Ratings

(a) *Maintenance of Credit Ratings.* As long as there remains any RUS Note, the Borrower shall (i) maintain a Credit Rating from at least two Rating Agencies and (ii) continuously subscribe with a Rating Agency for the services described in Exhibit C attached hereto.

(b) *Reporting Non-achievement of Investment Grade Credit Rating.* If the Borrower fails to maintain two Credit Ratings of Investment Grade, it must notify RUS in writing to that effect with five (5) days after becoming aware of such failure.

(c) *Corrective Plans.* Within thirty (30) days of the date on which the Borrower fails to maintain two Credit Ratings of Investment Grade, the Borrower in consultation with the RUS shall provide a 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.

(d) *Noncompliance.* Failure to implement a corrective plan developed in accordance with paragraph (c) of this section shall constitute an Event of Default under this Agreement.

ARTICLE VI. EVENTS OF DEFAULT

The following shall be "Events of Default" under this Agreement:

(a) *Representations and Warranties.* Any representation or warranty made by the Borrower in Article II hereof or, in any certificate furnished to the RUS hereunder or in the Loan Documents or in any filing pursuant to RUS Regulations shall be incorrect in any material respect at the time made and shall at the time in question be untrue or incorrect in any material respect and remain uncured;

(b) *Payment.* Default shall be made in the payment of or on account of interest on or principal of any RUS Note when and as the same shall be due and payable, whether by acceleration or otherwise, which shall remain unsatisfied for five (5) Business Days;

(c) *Other Covenants.* Default by the Borrower in the observance or performance of any other covenant or agreement contained in any of the Loan Documents, which shall remain unremedied for thirty (30) calendar days after written notice thereof shall have been given to the Borrower by the RUS;

(d) *Corporate Existence.* The Borrower shall forfeit or otherwise be deprived of its corporate charter or any franchise, permit, easement, consent or license required to carry on any material portion of its business;

(e) *Other Obligations.* Default by the Borrower in the payment of any obligation, whether direct or contingent, for borrowed money in excess of $1 million or in the performance or observance of the terms of any instrument pursuant to which such obligation was created or securing such obligation which default shall have resulted in such obligation becoming or being declared due and payable prior to the data on which it would otherwise be due and payable;

(f) *Bankruptcy.* A court having jurisdiction in the premises shall enter a decree or order for relief in respect of the Borrower in an involuntary case under any applicable bankruptcy, insolvency or other similar law now or hereafter in effect, or appointing a receiver, liquidator, assignee, custodian, trustee, sequestrator or similar official, or ordering the winding up or liquidation of its affairs, and such decree or order shall remain unstayed and in effect for a period ninety (90) consecutive days or the Borrower shall commence a voluntary case under any applicable bankruptcy, insolvency or other similar law now or hereafter in effect, or under any such law, or consent to the appointment or taking possession by a receiver, liquidator, assignee, custodian or trustee, of a substantial part of its property, or make any general assignment for the benefit of creditors; and

(g) *Dissolution or Liquidation.* Other than as provided in the immediately preceding subsection, the dissolution or liquidation of the Borrower, or failure by the Borrower promptly to forestall or remove any execution, garnishment or attachment of such consequence as shall impair its ability to continue its business or fulfill its obligations and such execution, garnishment or attachment shall not be vacated within thirty (30) days. The term "dissolution or liquidation of the Borrower," as used in this paragraph (g), shall not be construed to include the cessation of the corporate existence of the Borrower resulting either from a merger or consolidation of the Borrower into or with another corporation following a transfer of all or substantially all its assets as an entirety, under the conditions permitting such actions.

(h) *Indenture.* Any Event of Default as set forth in Section 8.1 of the Indenture and any event (as set forth in such Section 8.1) that with the giving of notice or the passage of time, or both, could become an Event of Default.

Big Rivers Electric Corporation
Case No. 2012-00535
Margins For Interest Ratio ("MFIR")
Fully Forecasted Test Period (September 2013 to August 2014)

Margins[1]	9,410,859
Interest Expense on LTD	46,983,291
Taxes	885
Total Numerator	56,395,035
Interest Expense on LTD	46,983,291
Total Denominator	46,983,291
MFIR	1.20

[1] Test Period Margins include proposed rate increase

MOODY'S
INVESTORS SERVICE

Issuer Comment: Big Rivers Electric Corporation -- Credit Opinion

Global Credit Research - 22 Aug 2012

Rating Drivers

» High industrial concentration to two aluminum smelters and dependence on off-system sales

» Rates subject to regulation by the Kentucky Public Service Commission (KPSC)

» Revenues from electricity sold under long-term wholesale power contracts with member owners

» Stronger balance sheet resulting from deleveraging following the unwinding of 1998 vintage transactions, which was completed in 2009

» Ownership of generally competitive coal-fired generation plants; pursuing environmental compliance plan, pending regulatory decision

Corporate Profile

Big Rivers Electric Corporation (Big Rivers) is an electric generation and transmission cooperative (G&T) headquartered in Henderson, Kentucky and owned by its three member system distribution cooperatives-- Jackson Purchase Energy Corporation; Kenergy Corp; and Meade County Rural Electric Cooperative Corporation. These member system cooperatives provide retail electric power and energy to about 113,000 residential, commercial, and industrial customers in 22 Western Kentucky counties.

Recent Events

Effective August 21, 2012 we downgraded the senior secured rating of $83.3 million of County of Ohio, Kentucky (the county) Pollution Control Refunding Revenue Bonds (Big Rivers Electric Corporation Project) to Baa2 from Baa1. Concurrently, the rating for the bonds, which were previously issued by the county on behalf of Big Rivers Electric Corporation, was placed under review for further downgrade. The rating actions primarily reflect increased financial and operating risks for Big Rivers due to the August 20, 2012 announcement by Century Aluminum Company (Caa1 senior unsecured; stable) that its subsidiary, Century Aluminum of Kentucky issued a 12-month notice to terminate its power contract with Big Rivers for its Hawesville, Kentucky smelter. See press release of August 21, 2012 posted to moodys.com for further details relating to this action.

Summary Rating Rationale

The Baa2 senior secured rating considers credit risk related to the fact that Big Rivers' largest member owner, Kenergy Corp., makes a high concentration of its sales to two aluminum smelters (Century Aluminum Company: senior unsecured Caa1; stable) and Rio Tinto: senior unsecured A3; stable), both of whom face credit challenges due to the significant volatility in both metal prices and demand. In addition, these smelters have the option to terminate their respective power purchase arrangements, subject to a one-year notice and other conditions. As noted above, Century exercised this option effective August 20, 2012. Big Rivers' rating is further constrained because its rates are regulated by the KPSC, which is atypical for the G&T coop sector. The Baa2 rating also reflects the financial benefits of several steps taken by Big Rivers to unwind a lease and other transactions in 2008 and 2009 wherein its prior deficit net worth turned substantially positive, cash receipts were utilized to reduce debt, and two committed bank credit facilities aggregating $100 million were established to improve liquidity. Revenues generated from reasonably competitive power sold to non-smelter customers under long-term wholesale contracts with the three member owners continue to support Big Rivers' financial performance. A $26.7 million (6.17%) base rate increase approved by the KPSC in September 2011 was also generally supportive in nature. The outcome of a pending filing before the KPSC related to future environmental related capital expenditures will be integral to Big Rivers' future financial performance as new debt financing will play a role in the financing strategy, particularly as it also copes with Century's recent contract termination notice.

Detailed Rating Considerations

High Smelter Load Concentration; Credit Challenge Tied to Potential Loss Of Smelter Load

Under historical operating conditions, the two smelters served by Kenergy have been consuming nearly 7 million MWh of energy annually, representing a substantial load concentration risk (e.g. about two-thirds of member energy load and close to 60% of member revenues for Big Rivers in 2011). This risk is a significant constraint to Big Rivers' rating, making its financial and operating risk profile unique compared to peers. All but one of Big Rivers' multiple transmission capacity upgrade projects undertaken in recent years are now complete, with the last remaining project estimated for completion in 2014 or 2015.. Also, Big Rivers became a transmission owning member of the Midwest Independent Transmission System Operator (MISO) in December 2010. As a result, Big Rivers has enhanced its reliability and transmission capability helping to ensure compliance with mandated emergency reserve requirements established by regulators. Also, these steps along with legislation that permits sales to non-members provide additional flexibility for Big Rivers to move excess power off system following Century's announcement.

Although Century is required to pay a base fixed energy charge (as defined to cover fixed and variable costs) for power (482 MW at 98% capacity factor) during the 12-month notice period, it is not required to continue operating the smelter plant. Despite the fact that Big Rivers will continue receiving base fixed energy charge revenues over the next 12 months, Big Rivers' rating is under review for downgrade as we consider the extent to which it can overcome revenue shortfalls to be created by the anticipated loss of a significant portion of its energy load. Among the possible mitigating steps Big Rivers might take would be using cash reserves established to partially compensate for loss of smelter load; entering into bilateral sales arrangements; making short-term off system sales in the wholesale market; participating in the capacity markets; temporarily idling generation; selling generating assets; and seeking emergency rate increases through filings with the KPSC. With respect to the latter possibility, we note that Big Rivers being rate regulated has in the past posed challenges in implementing timely rate increases.

Financial Flexibility Improved Following Completion Of Unwind Of Historical Transactions In 2009

In 2008, Big Rivers bought out two leveraged lease transactions and in 2009 completed a series of other steps to terminate another lease and other long-term transactions previously involving E.ON U.S. LLC (formerly known as: LG&E Energy Marketing Inc.) and Western Kentucky Energy Corp. These entities previously leased and operated the generating units owned by Big Rivers. In turn, Big Rivers was purchasing the power from these units at generally fixed below market rates to use in servicing the requirements of its three members, exclusive of the load requirements of Kenergy's two large aluminum smelters. At the same time, Big Rivers terminated other agreements and entered into various new arrangements whereby it has been selling to Kenergy 850 MW in aggregate for resale to the two aluminum smelters. This arrangement represents a concentration of load risk for Big Rivers. Key credit positives resulting from consummation of all the unwind transactions were as follows: elimination of Big Rivers' deficit net worth, with equity of $379.4 million at December 31, 2009, which increased to $389.8 million as of December 31, 2011 compared to a negative $155 million at 12/31/2008, and partial utilization of the $505.4 million in cash payments received from E.ON to repay about $140.2 million of debt owed to the Rural Utilities Service (RUS) and to establish $252.9 million of reserves. The reserves were comprised of: a $157 million Economic Reserve for future environmental and fuel cost increases; a $35 million Transition Reserve to mitigate potential costs if the smelters decide to terminate their agreements or otherwise curtail their load due to reduced aluminum production; and a $60.9 million Rural Economic Reserve, which would be used over two years to provide credits to rural customers upon full utilization of the Economic Reserve.

Under a contract times interest earned ratio (TIER) arrangement with the two smelters, Big Rivers targets a minimum TIER of 1.24x, which is above the level required under its financial covenants. Under current market conditions, we expect that Big Rivers would file for rate relief as necessary, as we would anticipate that the TIER drops below the 1.24x target should the contract with Century be terminated.

Coal-Fired Plants Represent Valuable Assets Even As Environmental Costs Loom

Big Rivers owns generating capacity of about 1,444 megawatts (MW) in four substantially coal-fired plants. Total power capacity is about 1,824 MW, including rights to about 202 MW of coal-fired capacity from Henderson Municipal Power and Light (HMP&L) Station Two and about 178 MW of contracted hydro capacity from Southeastern Power Administration. The economics of power produced from these sources enables Big Rivers to maintain a solid competitive advantage in the Southeast and even more so when compared to other regions around the country. The consistently high capacity factors and efficient operations of the assets results in average system wholesale rates to members around 4.7 cents per kWh (including the beneficial effects of the member rate stability mechanism). This compares to the average wholesale rate of 4.4 cents per kWh to serve the two smelter loads in 2011.

Because Big Rivers is substantially dependent on coal-fired generation, it faces uncertainty with regard to future environmental regulations, including the final form and substance those will take, the timing for implementation, and the amount of related costs to comply. We note that the Economic Reserve should help mitigate some of the need for initial rate increases to cover future compliance costs.

Regulatory Risk Exists; However, Offsets Are Present

Big Rivers is subject to regulation for rate setting purposes by the KPSC, which is atypical for the sector and can pose challenges in getting timely rate relief if and when needed. We view the existence of certain fuel and purchased power cost adjustment mechanisms available to Big Rivers as favorable to its credit profile since they can temper risk of cost recovery shortfalls if there is a mismatch relative to existing rate levels. Big Rivers received KPSC approval for a $26.7 million (6.17%) base rate increase effective November 17, 2011. We consider this a reasonably good outcome versus the approximate $30 million rate increase that was requested. The rate increase is intended to bolster wholesale margins, address increased depreciation costs, administrative costs tied to joining the Midwest Independent Transmission System Operator (MISO), and maintenance costs incurred during generation plant outages.

Big Rivers is in midst of regulatory proceedings at the KPSC relating to an environmental compliance plan. The extent to which timely and adequate regulatory support for recovery of environmental compliance costs appears evident will also be an integral part of the rating review process. The KPSC decision in this filing is expected in the fourth quarter of 2012.

Wholesale Power Contracts Support Big Rivers' Credit Profile

The revenues derived under Big Rivers' long-term wholesale contracts with its members for sales to non-smelter customers will continue as the contracts were extended by an additional 20 years to December 31, 2043 when the unwind of transactions were completed in 2009. The relatively low cost power provided under the contracts makes member disenchantment unlikely, even following recent base rate increases approved by the KPSC in 2011 and, in the medium to longer term, due to environmental compliance costs. The currently overall sound member profile provides assurance of this revenue stream, which is integral to servicing Big Rivers' debt. The potential for degradation in the creditworthiness of the smelters is a particular credit concern, only tempered in part by assurances of two month's worth of payment obligations covered by letters of credit from an A1 rated financial institution (or some other form acceptable to Big Rivers) under certain circumstances.

Big Rivers' net margins for 2011 reflected a modest decline versus 2010 as results in 2011 reflect the net effects of higher expenses in 2011 due to full year membership in MISO and the absence of one-time items that benefitted 2010 results, largely offset by an increase in 2011 net sales margin.

On a historical basis, Big Rivers dramatically improved its equity position whereby its equity to total capitalization is now over 30% thanks to significant debt reductions following the unwind. At this level, Big Rivers equity to total capitalization maps to the A category for this metric under the rating Methodology. Even with expected continuation of management's current practice of not returning patronage capital back to members (a credit positive strategy in our view) we anticipate that the equity ratio will decline moderately as new debt is added over the next couple of years to fund a capital program originally estimated at $550 million for 2012-2015, but which is likely to be reduced in the near term given recent developments related to environmental regulations. We also note that Big Rivers' historical three-year average metrics such as funds from operations (FFO) to debt and FFO to interest are particularly strong due to the one time effects of the unwind, and are therefore not sustainable at those levels.

Liquidity

Big Rivers supplements its internally generated funds with $100 million of unsecured committed revolver capacity, with National Rural Utilities Cooperative Finance Corporation (NRUCFC) and CoBank providing $50 million each. The NRUCFC and CoBank facilities expire on July 16, 2014 and July 27, 2017, respectively. The $50 million NRUCFC facility provides for issuance of up to $10 million of letters of credit. We view the significant increase in available bank credit following the completion of the unwind transaction in 2009 as credit positive. As of June 30, 2012 Big Rivers had approximately $48 million of cash and temporary investments and it currently has full capacity available under the two credit facilities. Assuming little change to future usage of the bank facilities and the cash position, as well as no change to management's current policy of not returning patronage capital back to members, we anticipate that Big Rivers should be able to adequately meet its short-term working capital needs and modest current maturities of long-term debt. However, new debt financing is anticipated over the next few years to fund any negative free cash flow resulting from the planned capital program. Following KPSC financing approval, Big Rivers completed about $537 million of financing transactions in aggregate with CoBank and NRUCFC on July 27, 2012 to prepay as planned a significant portion of its 5.75% RUS Series A note, fund a portion of its capital expenditures and to replenish its $35 million Transition Reserve balance. Approximately $235 million of this financing activity was completed through a 20-year senior secured term loan with CoBank and $302 million was completed through a 20-year senior secured term loan with NRUCFC.

The quality of the alternate liquidity provided by the bank revolvers benefits from the multi-year tenors and the absence of any onerous financial covenants, which largely mirror the financial covenants in existing debt documents. Big Rivers is in compliance with those covenants. Additionally, the NRUCFC facility benefits from no ongoing material adverse change (MAC) clause; however, the CoBank facility is considered of lesser quality because of the ongoing nature of its MAC clause related to each drawdown. There are no applicable rating triggers in any of the facilities that could cause acceleration or puts of obligations; however, a ratings based pricing grid applies.

Structural Considerations

As part of the unwinding of various transactions completed in 2009, Big Rivers replaced the previously existing RUS mortgage with a new senior secured indenture. Under the current senior secured indenture RUS and all senior secured debt holders are on equal footing in terms of priority of claim and lien on assets. The current senior secured indenture provides Big Rivers with the flexibility to access public debt markets without first obtaining a case specific RUS lien accommodation, while retaining the right to request approval from the RUS for additional direct borrowings under the RUS loan program, if they choose to do so. Given persistent questions about the availability of funds under the federally subsidized RUS loan program, we consider the added flexibility of the current senior secured indenture to be credit positive.

Rating Outlook

The rating is under review for downgrade as we assess the financial and operating effects and what mitigating strategies Big Rivers will pursue following Century's decision to submit its 12-month notice that it will terminate its power supply agreement with Big Rivers for its Hawesville, KY smelter plant.

What Could Change the Rating - Up

A rating upgrade is unlikely given the review for downgrade for reasons cited above. Success in mitigating the effects of load loss due to Century's announcement, regulatory support for environmental cost recovery and other future rate increases that may be necessary due to load loss could help stabilize the outlook. Moreover, structural changes that eliminate rate regulation of cooperatives in Kentucky could contribute to a positive action, especially if it coincides with improvement in market conditions for the aluminum smelters and sustained improvement of FFO to interest and debt metrics to near 2.3x and 8%, respectively, on average.

What Could Change the Rating - Down

Loss of significant load due to Century's announcement that is not otherwise compensated for through off system power sales or other measures could contribute to a negative action, as would the inability to secure needed rate increases from the non-smelter member load. From a regulatory perspective, the lack of a coherent recovery mechanism for environmental capital requirements, should they be incurred, could place downward pressure on the rating. In terms of credit metrics, if FFO to interest and debt falls below 2x and 5%, respectively, for a sustained period of time, then rating pressure could result.

Other Considerations

Mapping To Moody's U.S. Electric Generation & Transmission Cooperatives Rating Methodology

Big Rivers' mapping under Moody's U.S. Electric Generation &Transmission Cooperative rating Methodology is based on historical data through December 31, 2011. The Indicated Rating for Big Rivers' senior most obligations under the Methodology is currently A2 and relies on the aforementioned historical quantitative data and qualitative assessments. The Indicated Rating under the Methodology largely reflects better scores for the factors relating to dependence on purchased power and financial metrics such as equity as a percentage of capitalization, FFO to debt and FFO to interest, all of which improved upon completion of the unwind transactions in 2009. Notwithstanding the current A2 Indicated Rating for Big Rivers under the Methodology, its actual senior secured rating of Baa2 reflects the unique risks relating to Big Rivers' load concentration to the smelters and the fact that it is subject to rate regulation by the KPSC persist and represent significant constraints to its rating level.

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FitchRatings

FITCH PLACES BIG RIVERS ELECTRIC CORP, KY'S 2010A POLLUTION CONTROL RFDG REVS ON NEGATIVE WATCH

Fitch Ratings-New York-24 August 2012: Fitch Ratings has placed the 'BBB-' rating on the $83.3 million county of Ohio County, KY's pollution control refunding revenue bonds (Big Rivers Electric Corporation Project) series 2010A on Rating Watch Negative.

The rating action reflects the decision by Century Aluminum Co. (Century) to terminate its power contract with Big Rivers Electric Corporation and the uncertain effect that the termination will have on the electric cooperative's financial position and its ability to meet debt service payments.

SECURITY

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

WHAT COULD TRIGGER A RATING ACTION

INABILITY TO FIND ACCEPTABLE PURCHASERS: Extended over-reliance on short-term power sales as a replacement for the Century contract to meet debt service would likely result in a downward rating action.

INSUFFICIENT REGULATORY SUPPORT: Inadequate or untimely support by the Kentucky Public Service Commission (KPSC) would be viewed negatively.

IMPLEMENTATION OF REASONABLE MITIGATION PLAN: Implementation of a mitigation plan that maintains financial and operating stability would be supportive of credit quality.

CREDIT PROFILE

Big Rivers provides wholesale electric and transmission service to three electric distribution cooperatives. These distribution members provide service to a total of about 112,500 retail customers located in 22 western Kentucky counties. Kenergy Corporation, the largest of the three systems, is unique in that its electric load is dominated by two aluminum smelters, Rio Tinto Alcan (Alcan) and Century, which together account for more than one-half of Big River's operating revenues.

Century Terminates Contract

Under the power sales contracts between Kenergy and the smelters, which expire in 2023, the smelters are required to take-or-pay for specific quantities of energy, irrespective of their needs. The contracts further provide for termination on one years' notice without penalties subject to certain conditions including the termination and cessation of all aluminum smelting operations at the relevant facilities.

On Aug. 20, 2012, Century issued a notice to terminate its power contract with Big Rivers and stated its intent to close its Hawesville, KY smelter. Century claims that the smelter is not economically viable despite electric rates well below the national average and no apparent reduction in production.

Closure of the smelter has significant potential implications for Big Rivers, which has acknowledged the termination notice is valid. Besides the impact of the loss of some 700 plant employees, the remaining customers of Big Rivers will most likely have to absorb meaningfully higher rates, with the increase reflecting the amount, pricing and contractual provisions of surplus power sold to new customers.

Implementation of Mitigation Plan

Big Rivers management had previously developed a mitigation plan for the potential loss of the aluminum smelter loads and is presently looking into alternative arrangements with other power purchasers. However, implementation of future firm contractual arrangements will not likely occur immediately. As a result, it is likely that Big Rivers will begin the process of seeking emergency rate relief from the KPSC to help soften any negative effects from the expected loss of the smelter. According to Big Rivers, Alcan, the other larger smelter, has not expressed any intent to close its facility.

Future Financial Results Unclear

Big Rivers margins are expected to remain adequate to service financial obligations over the next 12 months, even with the expected closure of Century's facility, since Century remains obligated to make all required payments to Kenergy. However, as time passes, it will be necessary to decipher Big Rivers' revised business and financial plan and the effect on bond investors.

For additional information on the rating, see Fitch's report, 'Big Rivers Electric Corporation', dated Aug. 31, 2011, available at www.fitchratings.com.

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Additional information is available at 'www.fitchratings.com'. The ratings above were solicited by, or on behalf of, the issuer, and therefore, Fitch has been compensated for the provision of the ratings.

In addition to the sources of information identified in Fitch's Revenue-Supported Rating Criteria and U.S. Public Power Rating Criteria, this action was informed by information from CreditScope.

Applicable Criteria and Related Research:
--'Revenue-Supported Rating Criteria', June 12, 2012;
--'U.S. Public Power Rating Criteria', Jan. 11, 2012;
--'Big Rivers Electric Corporation', Aug. 31, 2011.

Applicable Criteria and Related Research:

Revenue-Supported Rating Criteria
http://www.fitchratings.com/creditdesk/reports/report_frame.cfm?rpt_id=681015
U.S. Public Power Rating Criteria
http://www.fitchratings.com/creditdesk/reports/report_frame.cfm?rpt_id=665815
Big Rivers Electric Corporation
http://www.fitchratings.com/creditdesk/reports/report_frame.cfm?rpt_id=649829

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RATINGS SERVICES

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Summary:

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

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Table Of Contents

Summary:

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

Credit Profile		
Big Rivers Electric Corp. ICR		
Long Term Rating	BBB-/Negative	Affirmed
Ohio Cnty, Kentucky		
Big Rivers Electric Corp., Kentucky		
Ohio Cnty (Big Rivers Electric Corp.) poll ctrl rfdg rev bnds (Big Rivers Elec Corp Proj) ser 2010A		
Long Term Rating	BBB-/Negative	Affirmed

Rationale

Standard & Poor's Ratings Services has revised its outlook on Big Rivers Electric Corp., Ky., (BREC) and Ohio County, Ky.'s $83.3 million pollution control refunding revenue bonds, series 2010A (Big Rivers Electric Corp. Project) issued for Big Rivers' benefit to negative from stable. At the same time, Standard & Poor's affirmed its 'BBB-' issuer credit rating on the cooperative and the issue-level rating on the Ohio County bonds.

The outlook revision reflects our concerns about the strength and stability of the utility's revenue stream following its leading customer's issuance of a 12-month notice to terminate its power contract with BREC. The notice covers Century Aluminum Co.'s (B/Stable/--) Hawesville, Ky., smelter. During the 12 months, Century is required to pay a base energy charge that covers its share of Big Rivers' fixed and variable costs. If it does not operate the plant during the notice period, it must still pay its share of fixed costs. BREC has accepted the termination notice.

Before sending its termination notice, Century claimed that its Hawesville smelting facilities require significant electric rate concessions to remain viable. Although the smelting plant has been operating at levels that exceeded its threshold electric contract requirements, the company cited sharp declines in aluminum prices and BREC's electric rates as factors that are degrading its Hawesville facilities' profitability. The utility did not accept the requested concessions, because its nonsmelter customers would have to bear the $110 million in concessions Century sought for itself and the utility's other smelter customer, Rio Tinto Alcan Inc. (Alcan; A-/Stable/A-2). That smelter is not projecting closing its Sebree facilities in BREC's service territory.

Century and Alcan represented two-thirds of BREC's 2011 megawatt-hour (MWh) sales to members, excluding nonmember sales, and about half of energy sales to members and nonmembers. Century accounted for about 30% of the utility's 2011 operating revenues and Alcan, 24%. About 80% of BREC's 2011 electric sales were to members and it sold the balance of its output principally in competitive wholesale markets. We view the pending loss of Century as having the potential to convert substantial amounts of the utility's generation capacity into surplus. Also, the departure could shift to BREC's remaining customers costs that Century historically paid.

Henderson, Ky.-based Big Rivers is a generation and transmission cooperative that produces and procures electricity for sale to three distribution cooperative members and their 112,900 retail customers. One member, Kenergy Corp., serves the two smelters. In 2011, Kenergy's 9.4 million MWh sales were 8x greater than the sum of the other two members' MWh sales. About 86% of Kenergy's 2011 MWh sales were to industrial customers. Nearly three-quarters of its sales were to the two smelters. They accounted for more than 70% of the company's operating revenues. BREC's other member distribution cooperatives--Jackson Purchase Energy and Meade County Rural Electric Cooperative--principally serve residential customers.

The smelters entered into take-or-pay power contracts with Kenergy. However, the contracts allow the smelters to terminate their obligations to the distribution utility and BREC without penalty if they provide one-year's notice and cease operations.

BREC plans to file for rate relief to compensate for Century's loss. The rate filing will request that the Kentucky Public Service Commission (KPSC) reallocate costs historically borne by Century to BREC's remaining customers by raising their rates. We view the service area's composition as potentially frustrating the ability to reallocate costs. We believe that Alcan might resist efforts to have it absorb costs its competitor previously covered. Also, many of the counties that BREC serves have income levels that are 20%-30% below the national median household effective buying income, which could hinder the reallocation of Century costs to residential customers. In addition, because the KPSC must approve the request for rate adjustments, the utility and its member distribution cooperatives are distinguishable from many other cooperative utilities that have autonomous ratemaking authority. Because the cooperative and its members are regulated, it is uncertain whether the rate relief request that BREC is planning will be approved in full or in part.

During rate negotiations between BREC and Century, the utility reported that applying the smelter's requested rate concessions to both smelters to maintain parity would have meant raising the system's residential customers' rates about 37% and its industrial customers' rates about 56%. It now expects to seek more modest rate increases that reflect the reallocation of Century's costs to remaining customers.

BREC is also evaluating idling power plants as part of its response to losing loads. Closing plants could reduce costs, reduce market exposure and mitigate the financial impact on remaining customers. The utility might also temper the burdens of cost reallocation if it can remarket some or all of the generation output that had been sold to the smelters. However, market or contract demand and prices would need to be sufficient to recoup Century's share of costs or mitigate the loss of the company's contribution to cost recovery.

Based on historical market sales and Century's share of purchases, we believe that market sales could transform the utility into a principally merchant generator that faces the risks inherent in being subject to market demand and prices. The smelters' large share of energy sales could make it difficult to resell so much of the utility's generating capability. In addition, the utility's very high dependence on coal units might also constrain market sales opportunities. Coal accounts for close to 90% of its power sales and coal units are not as economical as gas-fired resources that are benefitting from the fuel's low prices.

BREC sells electricity to the smelters under contracts at prices that are about 30% above the 3.3 cents it earned from sales of surplus energy in wholesale markets in 2011. It sold 3 million MWh of surplus wholesale power into the market for $100.4 million in 2011.

Coal resources also expose the utility to potentially higher production costs as Environmental Protection Agency (EPA) regulation of power plant emissions progresses. A recent appellate decision that vacated the EPA's Cross-State Air Pollution rule could provide the utility with at least a temporary reprieve from emissions-related capital spending while the EPA revisits its rules.

The utility reported $794 million of debt as of June 30, 2012. Debt consisted of Rural Utilities Service loans and the Ohio County bonds. Big Rivers closed a $537 million loan with CoBank ACB and National Rural Utilities Cooperative Finance Corp. in July. In addition to replenishing $35 million of transition reserve funds, proceeds restructured a portion of the utility's RUS borrowing to eliminate some of the spikes in debt service requirements.

The debt portfolio exhibits uneven amortization. BREC repaid $14.2 million of principal in 2010. In 2011, it was required to repay $7.3 million of principal, but also used $35 million of transition reserve monies to accelerate principal reduction. The utility replenished the transition reserve in 2012 with proceeds of July's borrowing from CoBank and National Rural Utilities. Loan proceeds also facilitated debt restructuring that reduced 2012's $72.1 million scheduled maturity to $12.1 million, with the remaining $60 million to be amortized in later years. However, 2013's maturity remains at $79.3 million, and that will likely need to be restructured. The utility forecasts about $22 million of 2014 and 2015 principal payments.

Ohio County sold bonds for the benefit of BREC, which used bond proceeds to refund auction rate securities. We understand that the financing structure obligates the utility to unconditionally pay the county's bonds' debt service. Big Rivers issued a note to the county that provides it with a security interest in the utility's assets under its mortgage indenture. The county's bonds' security interest is on par with the utility's senior-secured debt.

Debt service coverage of 1.45x in 2010 and 1.65x in 2011 was strong for a cooperative utility, in our opinion. We believe strong excess coverage margins provide a cushion against the potential for revenue stream variability.

The strength of 2011's coverage ratio partially reflects the year's very low scheduled principal payment of $7.3 million. We calculated the ratio using scheduled debt service in the denominator, compared to the $46 million of principal the utility elected to repay.

The utility maintains $152.6 million of reserves that it uses for rate stabilization to reduce rates. Because it already projects depleting these reserves by the first quarter of 2018 under a steady-state scenario, we do not view these reserves as adding value under a scenario in which the smelters receive rate concessions or close.

Outlook

The negative outlook reflects our view that the largest customer's decision to close facilities after failing to win rate concessions could degrade BREC's financial performance and credit quality during our two-year outlook horizon. Although the utility plans to file for rate relief, we view rate cases as presenting uncertainty vis-à-vis the extent and timeliness of rate relief. We will monitor the progress of the rate case to assess whether further rating action is appropriate. The customer's notice could also expose the utility to the vicissitudes of merchant markets and creates the potential for substantial cost shifting to remaining customers, who might resist such efforts or find that reallocated costs are too onerous to absorb. If these risks, whether in isolation or combination, weaken BREC's business risk profile and erode financial metrics, including the strong debt service coverage that compensated for business risks in recent years, we could lower the ratings. We do not expect to raise the ratings during our outlook period.

Related Criteria And Research

USPF Criteria: Applying Key Rating Factors To U.S. Cooperative Utilities, Nov. 21, 2007

Complete ratings information is available to subscribers of RatingsDirect on the Global Credit Portal at www.globalcreditportal.com. All ratings affected by this rating action can be found on Standard & Poor's public Web site at www.standardandpoors.com. Use the Ratings search box located in the left column.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

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

DIRECT TESTIMONY

OF

ALBERT M. YOCKEY
VICE PRESIDENT GOVERNMENTAL RELATIONS and
ENTERPRISE RISK MANAGEMENT

ON BEHALF OF

BIG RIVERS ELECTRIC CORPORATION

FILED: January 15, 2013

DIRECT TESTIMONY
OF
ALBERT M. YOCKEY

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DIRECT TESTIMONY
OF
ALBERT M. YOCKEY

I. INTRODUCTION

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

A. My name is Albert M. Yockey. My business address is 201 Third Street, Henderson, Kentucky 42420. I am employed by Big Rivers Electric Corporation ("Big Rivers") as its Vice President, Governmental Relations and Enterprise Risk Management.

Q. Please describe your job responsibilities.

A. As the Vice President, Governmental Relations and Enterprise Risk Management, I am responsible for risk management and government relations including interaction with elected officials and legislative bodies plus proceedings before the Kentucky Public Service Commission ("the Commission"). Personnel reporting to me are also responsible for Marketing and Member Relations, Strategic Planning, Performance Indicators, and representing Big Rivers in other utility-related collaboratives. The latter recently have included the Statewide Demand-Side Management and Energy Efficiency Stakeholder collaborative facilitated by the Kentucky Department for Energy Development and Independence, the Regulatory Advisory Working Groups convened by the

Commission Staff, and electric utility collaboratives in Case No. 2008-00408.

Q. Briefly describe your education and work experience.

A. I received a Bachelor of Science in Electrical Engineering, Cum Laude, from the University of Pittsburgh in April, 1972. In May, 1979, I received a Master of Science in Electrical Engineering from Lehigh University. In May, 1994, I was awarded a Juris Doctorate from The Capital University in Columbus, Ohio. I am a registered attorney in the State of Ohio.

While working on my undergraduate degree at the University of Pittsburgh, I worked as a summer laborer and engineering aide at the West Penn Power Company's Springdale Power Station. Upon graduating from the University of Pittsburgh, I was employed by the Pennsylvania Power & Light Company ("PP&L") as a Relay Engineer in the System Operating Department in 1972 and was promoted to a Project Engineer in 1976.

At PP&L, the focus of my work was system protection and related requirements. From 1977 to 1981, I was a Project Engineer in the Electrical Section of System Planning. Among many duties, I ran computer simulations of electrical systems, performed economic analysis of alternative expansion plans, and developed five-year and long-range plans for system reinforcements. As a Project Engineer in the Energy Assessment and Capacity Planning Section of System Planning from 1981 to 1985, I made economic evaluations of co-generation and alternative energy projects, assessed various energy and demand management options, and reviewed potential capacity and energy sales to other utilities.

In 1985, I accepted a position as Senior Engineer in the Area Transmission Planning Section of the System Planning Department of American Electric Power ("AEP") Service Corporation in Columbus, Ohio. My responsibilities included ensuring reliable operation of transmissions facilities under normal and facility outage conditions, identifying future system requirements, and justifying needed changes to management. As such, I worked with many internal cross-functional teams, external customers, other utilities, and regulatory agencies.

In 2000, I became the Manager of Transmission Strategic Issues reporting to the Vice President of Transmission Asset Management. My responsibilities included divisional regulatory/legislative strategy development and coordination. More specifically, I managed multiple state and federal requirements which required interfacing, as needed, with AEP departments within and outside transmission, and with commissions and their respective staffs across the AEP footprint. I held that position until 2008 when I came to Big Rivers. My professional summary is attached to this testimony as Exhibit Yockey-1.

Q. Have you previously testified before the Commission?

A. Yes. I testified in the rate case Big Rivers filed in 2011, Case No. 2011-00036 (the "2011 Rate Case"), and I appeared before this Commission on behalf of Big Rivers in Administrative Case No. 2008-00408. I have also participated in various informal conferences at the Commission including in the case relating to Big Rivers joining the Midwest Independent Transmission System Operator, Inc. ("MISO"), Case No. 2010-00043, and I have assisted in preparing responses to requests for information in Big Rivers' recent environmental compliance plan case, Case No. 2012-00063, and in Big Rivers' Fuel Adjustment Clause ("FAC") and Environmental Surcharge ("ES") review cases before this Commission.

Q. Have you previously been involved with other regulatory proceedings?

A. Yes. Prior to my arrival at Big Rivers, my career included interfacing with numerous state commissions, and their respective staffs, during my tenure with AEP in Columbus, Ohio. These commissions were across the AEP footprint. I assisted in the preparation of testimony for AEP rate proceedings in Texas and Oklahoma.

II. <u>PURPOSE OF TESTIMONY</u>

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the tariff changes Big Rivers is proposing, to sponsor certain filing requirements, to describe the costs associated with this filing, and to describe Big Rivers' commitment to demand-side management ("DSM") and energy efficiency programs.

Q. Are you sponsoring any exhibits?

A. Yes. In addition to my professional summary, Exhibit Yockey-1, I am also sponsoring a tabular summary of the changes to the energy and demand charges in Big Rivers' proposed tariff versus its current tariff in Exhibit Yockey-2. Finally, Exhibit Yockey-3 summarizes Big Rivers' DSM and energy efficiency programs.

III. DESCRIPTION OF TARIFF CHANGES

Q. Please summarize the changes Big Rivers is proposing to its existing tariff.

A. A summary of changes in energy and demand charges in Big Rivers' current tariff is contained in Exhibit Yockey-2. The analysis supporting these changes is presented in the Direct Testimony of Mr. John Wolfram. Big Rivers has also reviewed its current tariff for non-substantive grammatical and spelling errors and corrected them. These changes, along with all changes to energy and demand charges, have been noted as prescribed by 807 KAR 5:011 Section 6(2)(a). Also, the footer for each tariff sheet has been adjusted to provide space in the lower right-hand corner for the file stamp of the Commission's Tariff Branch. This change reflects the revised Commission regulations for 807 KAR 5:011, which went into effect on January 4, 2013.

Q. Have you detailed the proposed tariff changes in any way?

A. Yes. As required in 807 KAR 5:001 Section 10(l)(b)(8), Big Rivers has presented its current tariff and its proposed tariff in a side-by-side comparison. (*See* Tab 9 to the application.) That comparison shows each proposed change and, as mentioned above, notes those changes using the margin indicators prescribed in 807 KAR 5:011 Section 6(2)(a). The Commission number of the proposed tariff is PSC KY No. 25, and therefore, all marginal notations note the changes from Big Rivers' current tariff on file with the Commission, designated as PSC KY No. 24.

Q. Please further describe the changes reflected in Big Rivers' proposed tariff.

A. Language referring to Big Rivers' Standard Rate Schedules listed in Section 1 of the Table of Contents has been standardized. For example, some current language might read "Rate Schedule RDS," "Rate Schedule LIC,"' "'Schedule RDS," or "Schedule LIC." In those areas of the proposed tariff, that language consistently reflects "Standard Rate Schedule RDS," "Standard Rate Schedule LIC," *etc.*

Also, references to the current tariff's Discount Adjustment subsection within Section 3 have been altered. That language now consistently reads "Section 3 – Special Rules, Terms, and Conditions: Discount Adjustment."

Big Rivers' proposed tariff also reflects more consistent use of the terms "Member,", "Members," "Member Cooperative," and "Member Cooperatives." Some uses of these terms in the current tariff are in lower case. Other language in the current tariff reads, "[R]ural electric distribution cooperatives." In the latter case, Big Rivers substitutes the term "Member Cooperatives."

Big Rivers' proposed Standard Rate Schedule QFS, as with the current tariff, defines the clock times associated with the summer on-peak and winter on-peak time periods. In the proposed tariff, these clock times are now shown as CPT, or Central Prevailing Time, and that term has been added to Section 4 – Definitions. Other terms have also been added to Section 4 – Definitions.

Big Rivers' current tariff contained different, but comparable, language referring to notice periods, *e.g.*, a forty-eight (48) hour notice, by giving forty-eight (48) hours notice, and by giving forty-eight hours' notice. In its proposed tariff, Big Rivers consistently uses the phrase "a forty-eight (48) hour notice."

Big Rivers has also updated the language in Section 3 – Special Rules, Terms, and Conditions: Transmission Emergency Control Program and Section 3 – Special Rules, Terms, and Conditions: General Deficiency

Emergency Control Program. Both subsections now include introductory paragraphs describing how the respective procedures are impacted by Big Rivers' membership in MISO. Other changes reflect corrections of grammar and punctuation, changes of verb tense from passive to active, and reflection of a greater use of electronic information (use of screens, saving to electronic media, *etc.*) versus hardcopy printouts.

IV. FILING REQUIREMENTS FROM 807 KAR 5:001

Q. Have you reviewed the answers provided in Tabs 1 through 62, which address Big Rivers' compliance with forecasted period filing requirements under 807 KAR 5:001 and its various subsections?

A. Yes, I have, and I hereby incorporate and adopt those portions of Tabs 1 through 62 for which I am identified as the sponsoring witness as part of this Direct Testimony.

V. RATE CASE COSTS

Q. Has Big Rivers projected the costs of professional services related to the preparation and prosecution of this rate filing?

A. Yes. The total projected rate case cost is $1,585,977. The development of this estimate and the manner in which the amount is built into Big Rivers' budget is discussed in the Direct Testimony of Ms. DeAnna M. Speed. Big Rivers has acquired valuable experience with outside service firms in major cases over the last two years, including the 2011 Rate Case and Big Rivers' 2012 environmental compliance plan case, Case No. 2012-00063. This has enhanced Big Rivers' ability to estimate the costs for outside service support for filings of this magnitude.

Q. What steps is Big Rivers taking to ensure that the actual rate case costs incurred in this proceeding are reasonable?

A. Big Rivers is closely managing its rate case costs in several ways. First, Big Rivers addressed the issue of outside legal expenses, which was contested in the 2011 Rate Case. Big Rivers continues to rely on Sullivan, Mountjoy, Stainback & Miller PSC ("SMSM") for primary legal support for this filing; however, to secure additional support as resource needs warrant, Big Rivers also retained Dinsmore & Shohl ("Dinsmore"), a law firm with offices in Frankfort, Lexington, Louisville, Cincinnati, and other cities. Dinsmore's attorneys have experience with regulatory proceedings before the Commission, charge hourly rates that are comparable to other firms in Kentucky, and are located in close proximity to both Big Rivers' and the Commission's offices – all of which allows Big Rivers to reduce its costs for legal counsel and travel while maintaining the necessary high level of legal expertise.

Second, Big Rivers issued a Request For Proposals ("RFP") for the depreciation study and selected Burns & McDonnell, in part, because of its competitive pricing relative to other RFP respondents, as described in the Direct Testimony of Ms. Billie J. Richert.

Third, Big Rivers is closely monitoring the actual rate case costs from its professional service firms on an on-going basis. Big Rivers closely reviews monthly invoices and performs a contemporaneous variance analysis which compares actual rate case costs to budget after the Company's books close each month. This allows Big Rivers to make adjustments to its plans for upcoming meetings, conference calls, assignments for drafting and reviewing documents, and other tasks as warranted. Big Rivers expects to continue this review and evaluation through the balance of this proceeding.

Fourth, Big Rivers also monitors the work of its outside professionals. Big Rivers assigned a project manager for this case to track the tasks assigned to and work performed by outside professionals, and Big Rivers' personnel and the outside professionals have worked closely together throughout the preparation of the application and testimony.

VI. DSM AND ENERGY EFFICIENCY

Q. Please explain Big Rivers' consideration of cost-effective energy efficiency resources?

A. Big Rivers currently has no plans to add additional generating resources, and Big Rivers is committed to developing a robust set of cost-effective DSM and energy efficiency programs to help eliminate or delay the need for additional generating resources in the future. Also, as explained in the Direct Testimony of Mr. Robert W. Berry, Big Rivers continues to work to improve the efficiency of its existing generating units.

Q. Please describe the development of Big Rivers' existing DSM and energy efficiency programs?

A. In 2009, the Commission approved the termination of a 1998 transaction whereby Big Rivers leased its generating units to affiliates or subsidiaries of what later became E.ON U.S., LLC ("E.ON") and E.ON sold fixed-priced power to Big Rivers. That 2009 transaction is known as the "Unwind Transaction."

After the Unwind Transaction closed in 2009 and Big Rivers regained control of its generating units, Big Rivers and its three distribution cooperative members ("Members") began to take steps to increase the availability of DSM and energy efficiency programs on the Big Rivers system beyond the distribution of compact fluorescent lights (CFLs) to the

Members' retail customers. Big Rivers and its Members established a DSM and energy efficiency working group (the "DSM/EE Working Group") to evaluate, design, and implement cost-effective DSM/energy efficiency programs. The DSM/EE Working Group began meeting in 2009. Big Rivers' Manager of Marketing and Member Relations, other Big Rivers personnel, and staff from Big Rivers' Members all participate in the DSM/EE Working Group.

The DSM/EE Working Group engaged GDS Associates to develop a DSM Potential Study, which was filed with the Commission on November 15, 2010, as Appendix B to Big Rivers' 2010 Integrated Resource Plan ("IRP") in Case No. 2010-00443. In that study, GDS Associates evaluated over 200 residential and commercial DSM/energy efficiency programs and recommended cost-effective programs to meet a $1 million budget, which was the starting point for the programs Big Rivers selected to offer as pilots in 2011. In Big Rivers' 2011 Rate Case, Big Rivers sought and was granted a $1 million *pro forma* adjustment for its DSM/energy efficiency programs.

Also, in the Commission's November 17, 2011, Order in the 2011 Rate Case, the Commission directed Big Rivers to file semi-annual reports on the status of its DSM/EE programs. Big Rivers filed reports complying with Ordering Paragraph No. 9 of that Order on January 31, 2012, and July 31, 2012. The next such report is due on January 31, 2013.

By letter dated November 29, 2011, the Commission required DSM programs to be tariffed ("the November 2011 Letter"). On March 16, 2012, in response to that letter, Big Rivers filed tariffs for the nine DSM/energy efficiency programs that it developed based on the 2011 pilot programs. Subsequently, on April 20, 2012, Big Rivers filed a tariff for one additional DSM/energy efficiency program, bringing the total DSM/energy efficiency portfolio to ten programs. A summary of these programs is provided in Exhibit Yockey-3.

The Commission approved these tariffs in its Order dated August 22, 2012, in Case No. 2012-00142. The programs are described in more detail in the DSM Potential Study, including cost/benefit analyses and potential energy savings. Big Rivers continues to offer these ten DSM/energy efficiency programs, and each of Big Rivers' three Members offers some or all of the programs. The DSM/EE Working Group continues to evaluate additional programs, including outdoor lighting and demand response.

Q. How much of the $1 million that was approved in Big Rivers' most recent rate case for DSM/energy efficiency programs did Big Rivers spend in 2012?

A. Of the $1 million that the Commission approved, $800,000 was for Big Rivers to reimburse its Members for incentives they provide to their customers under the DSM/energy efficiency programs and $200,000 was for Big Rivers to reimburse its Members for their promotional expenses for the

DSM/energy efficiency programs. As of December 31, 2012, Big Rivers has reimbursed its Members for approximately $513,000 for incentives and for $104,000 for promotional and administrative expenses, for a total of $617,000.

Q. How much is Big Rivers seeking in this rate case for its DSM/energy efficiency programs?

A. Big Rivers requests that the Commission continue the $1 million allocated for DSM/energy efficiency programs. For 2013, Big Rivers intends to spend not only the $1 million that was approved in the 2011 Rate Case, but also any amounts that were left over from 2012. In total, Big Rivers has budgeted $1.3 million for its DSM/energy efficiency programs in 2013.

Big Rivers did not spend the full $1 million in 2012 because the programs were still being ramped up throughout the year. Furthermore, the Commission's November 2011 Letter directing Big Rivers and its Members to obtain approval of their DSM tariffs caused delays, to varying degrees, in the Members implementing the programs. The Members chose to offer DSM programs when tariffs were under review by the Commission. Meade County Rural Electric Cooperative Corporation began offering programs in January 2012, Kenergy Corp. in May 2012, and Jackson Purchase Energy Corporation in September 2012. However, now that all three of the Members are offering programs, Big Rivers should be able to meet the $1.3 million budget in 2013.

Big Rivers anticipates that its slate of DSM/energy efficiency programs will escalate in the future, and the DSM/EE Working Group continues to evaluate potential measures to offer, including demand response opportunities. These efforts will be further documented in Big Rivers' next IRP. While Big Rivers does not currently have any plans to construct new generating facilities, Big Rivers' efforts to develop cost-effective DSM/energy efficiency programs are consistent with its commitment in Administrative Case No. 2008-00408 to adopt the Commission's Kentucky IRP Standard[1] and to consider cost-effective energy efficiency resources with equal priority as other resource options.

VII. OTHER PROCEEDINGS

Q. Are there any open proceedings that might impact this case?

A. Yes. The relevant open proceedings include a two-year ES review in Case No. 2012-00262 and the 2011 Rate Case, Case No. 2011-00036. The Commission's orders in these cases could affect the rates proposed in this proceeding. More specifically, if the Commission adjusts Big Rivers' ES

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[1] The Kentucky IRP Standard, as adopted by the Commission in its July 24, 2012, Order in Case No. 2008-00408, provides:

> Each electric utility shall integrate energy efficiency resources into its plans and shall adopt policies establishing cost-effective energy efficiency resources with equal priority as other resource options. In each integrated resource plan, certificate case, and rate case, the subject electric utility shall fully explain its consideration of cost-effective energy efficiency resources as defined in the Commission's IRP regulation (807 KAR 5:058).

rate in the ES review case for any reason, e.g., increasing the ES portion in base rates (commonly referred to as a roll-in), Big Rivers would need to file updated tariff sheets, from its current tariff, reflecting this roll-in. This roll-in would not change the amount of the proposed increase. Also, the application in this proceeding assumes that the Commission makes no changes on rehearing to its November 17, 2011, Order in the 2011 Rate Case except that it assumes Big Rivers is granted the full amount of rate case expenses sought in that case. If the Commission issues an order on rehearing in that case granting less than the full amount of Big Rivers' rate case expenses or making other changes to its November 17, 2011, Order, Big Rivers will need to re-file certain exhibits in this proceeding, such as certain of the exhibits to the Direct Testimony of Mr. John Wolfram, update the amount of the revenue deficiency, and file revised tariff sheets, as necessary.

Q. Are there any anticipated proceedings that might impact this case?

A. Yes. Big Rivers anticipates that the Commission will soon open a docket for the two-year review of its FAC mechanism. Big Rivers further anticipates that the hearing and final Commission Order in that two-year FAC review will occur before this proceeding concludes. At this time, Big Rivers does not know if it will propose a roll-in of any fuel costs into base rates. Should Big Rivers propose any such roll-in and should the Commission approve that roll-in, then Big Rivers would need to file updated tariff sheets, from its current tariff, reflecting this roll-in. As with the ES roll-in described above, any such roll-in would not change the amount of the proposed increase.

VIII. CONCLUSION

Q. What are your conclusions and recommendations to the Commission in this proceeding?

A. I recommend that the Commission continue the $1 million allocated for DSM/energy efficiency programs, grant Big Rivers the rate relief it is seeking in this proceeding, and approve the proposed tariff changes described above.

Q. Does this conclude your testimony?

A. Yes.

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES CASE NO. 2012-00535

VERIFICATION

I, Albert M. Yockey, verify, state, and affirm that I prepared or supervised the preparation of my testimony filed with this Verification, and that testimony is true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Albert M. Yockey

Albert M. Yockey

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Albert M. Yockey on this the 9th day of January, 2013.

Paula Mitchell

Notary Public, Ky. State at Large
My Commission Expires 1-12-17

Professional Summary

Albert M. Yockey
Vice President, Government Relations and Enterprise Risk Management
Big Rivers Electric Corporation
201 3rd Street
Henderson, Kentucky 42420
(270) 844-6180

Professional Experience

Big Rivers Electric Corporation 2008 to present

Vice President, Government Relation and Enterprise Risk Management

AEP Service Corporation 1985 – 2008

Manager, Transmission Strategic Issues

Senior Engineer, Area Transmission Planning Section – System Planning Department

Pennsylvania Power & Light (PP&L) 1972 – 1985

Project Engineer, Energy Assessment/Capacity Planning Section – System Planning

Project Engineer, Electrical Section – System Planning

Project Engineer, System Operating Department

Relay Engineer, System Operating Department

West Penn Power 1968 – 1972

Engineering Aide, Springdale Power Station

Education

Juris Doctrate, 1994

The Capital University

MS Electric Engineering, 1979

Lehigh University

BS Electric Engineering (*Cum Laude*), 1972

University of Pittsburgh

Big Rivers Electric Corporation
Case No. 2012-00535
Summary of Proposed Changes to Tariff Rates

Standard Rate Schedule	Rate	Sheet Number(s)	Current Rate	Proposed Rate[1]	Incr. (Decr.)[1]
RDS	Demand	1	$9.5000 per kW	$16.9500 per kW	$7.45 per kW
	Energy	1	$0.029736 per kWh	$0.030000 per kWh	$0.000264 per kWh
LIC	Demand	7	$10.5000 per kW	$12.4100 per kW	$1.9100 per kW
	Energy	7	$0.024505 per kWh	$0.030000 per kWh	$0.005495 per kWh
QFS	*On-Peak Maintenance Service*				
	Demand per Week	24	$2.1920 per kW	$3.9550 per kW	$1.7630 per kW
	Energy	24	$0.029736 per kWh	$0.030000 per kWh	$0.000264 per kWh
	Off-Peak Maintenance Service				
	Demand per Week	24	$2.1920 per kW	$3.9550 per kW	$1.7630 per kW

[1] Please see the Direct Testimony of Mr. John Wolfram for analysis supporting these proposed rates.

Big Rivers Electric Corporation
Case No. 2012-00535
DSM Program Summary

Standard Rate Schedule	DSM Program Number	DSM Program Title	Tariff Sheet Number(s)	
			Current Tariff	Proposed Tariff
RDS	DSM-01	High Efficiency Lighting Replacement Program	2.01	3
	DSM-02	ENERGY STAR® Clothes Washer Replacement Incentive Program	2.02	4
	DSM-03	ENERGY STAR® Refrigerator Replacement Incentive Program	2.03 – 2.04	5 – 6
	DSM-04	Residential High Efficiency Heating, Ventilation and Air Conditioning ("HVAC") Program	2.05 – 2.06	7 – 8
	DSM-05	Residential Weatherization Program	2.07 – 2.08	9 – 10
	DSM-06	Touchstone Energy® New Home Program	2.09 – 2.10	11 – 12
	DSM-07	Residential and Commercial HVAC & Refrigeration Tune-Up Program	2.11	13 – 14
	DSM-08	Commercial / Industrial High Efficiency Lighting Replacement Incentive Program	2.12 – 2.13	15 – 16
	DSM-09	Commercial / Industrial General Energy Efficiency Program	2.14 – 2.15	17 – 18
	DSM-10	Residential Weatherization Program – Primary Heating Source Non-Electric	2.16 – 2.17	19 – 20

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

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

DIRECT TESTIMONY

OF

ROBERT W. BERRY
VICE PRESIDENT, PRODUCTION

ON BEHALF OF

BIG RIVERS ELECTRIC CORPORATION

FILED: January 15, 2013

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I. <u>INTRODUCTION</u>

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

A. My name is Robert W. Berry. I am employed by Big Rivers Electric Corporation ("Big Rivers"), 201 Third Street, Henderson, Kentucky 42420 as its Vice President of Production. I have held this position since July 2009, upon the closing of the transaction that unwound Big Rivers' 1998 lease with E.ON U.S., LLC and its affiliates (the "Unwind Transaction"), described in Case No. 2007-00455. Prior to the closing of the Unwind Transaction, I was employed by Western Kentucky Energy Corporation ("WKE") for 11 years beginning as a Maintenance Manager in 1998. I held the position of Plant Manager of the Coleman Generating Station from 2000 until 2003 at which time I became the Plant Manager of the Sebree Generating Station. Altogether, I have over 31 years of experience in this system, having worked for both Big Rivers and WKE.

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

A. Yes. I testified most recently on behalf of Big Rivers in its last general rate case, Case No. 2011-00036 (the "2011 Rate Case"), and in its 2012 Environmental Compliance Plan case, Case No. 2012-00063.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to: (i) describe Big Rivers' generating assets and the performance of its generating units, in support of Big Rivers' request for sufficient revenue to be able to continue to prudently maintain its generating units on an ongoing basis while satisfying the obligations in its loan agreements; (ii) describe the efforts Big Rivers has undertaken and plans to take to mitigate the effects of the contract termination by Century Aluminum of Kentucky General Partnership ("Century"); (iii) support Big Rivers' request to recover certain expenses resulting from its membership in the Midwest Independent Transmission System Operator, Inc. ("MISO"); (iv) briefly describe Big Rivers' production cost modeling and load forecast; and (v) support certain filing requirements.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

1. Exhibit Berry-1 Comparison of Outage Schedule at Unwind Transaction Closing and Current Outage Schedule;
2. Exhibit Berry-2 Production Non-Labor Fixed Departmental Expenses (FDE);
3. Exhibit Berry-3 Capital Work Plan; and
4. Exhibit Berry-4 Estimated Impact of Century Contract Termination.

III. PLANT PERFORMANCE

Q. Please describe Big Rivers' power production resources.

A. Big Rivers currently owns and operates 1,444 MW of net generating capacity in four stations: (i) Kenneth W. Coleman Station (443 MW) in Hawesville, Kentucky; (ii) Robert A. Reid Station (130 MW) in Robards, Kentucky; (iii) Robert D. Green Station (454 MW) in Robards, Kentucky; and (iv) D. B. Wilson Station (417 MW) in Centertown, Kentucky. Big Rivers also has contractual rights to 197 MW from the "Station Two" unit owned by Henderson Municipal Power and Light ("HMP&L") and 178 MW from the Southeastern Power Administration ("SEPA"), for a total net capacity availability of 1,819 MW. The SEPA contract is currently in *force majeure* due to safety issues at the Wolf Creek and Center Hill dams, so Big Rivers is only receiving a run-of-the-river schedule that it has the right to refuse. The Wolf Creek dam is expected to return to normal operation in January 2015, at which time the full 178 MW of capacity will be available to be scheduled by Big Rivers.

Q. Has the Station Two capacity changed since Big Rivers filed the 2011 Rate Case?

A. Yes. Big Rivers' share of the Station Two capacity was 207 MW on March 1, 2011, when Big Rivers filled its 2011 Rate Case. HMP&L has the contractual right to increase or decrease its capacity reservation from

Station Two up to 5 MW each year to meet the needs of the City of Henderson and its residents. HMP&L exercised that right in June 2011 and June 2012, reducing Big Rivers' share of Station Two capacity from 207 MW to 197 MW.

Q. How does Big Rivers benchmark the reliability performance of its generating units relative to others in the industry?

A. A commonly used industry standard for measuring the reliability of coal-fired generating units is the weighted average Equivalent Forced Outage Rate ("EFOR"). Big Rivers determines EFOR for its generating system using the NERC Generator Availability Data System ("GADS") and can compare its EFOR against other utilities. Big Rivers can also rely on Equivalent Availability Factor ("EAF") and Net Capacity Factor ("NCF") in making reliability comparisons to other utilities in the industry. Big Rivers uses Navigant Consulting's "Generation Knowledge Service" to compare its plant reliability to similar units across the region.

Q. How does Big Rivers' generation reliability compare to that of other utilities?

A. Overall, the Big Rivers generating fleet has been very reliable since closing of the Unwind Transaction in July 2009, and has consistently performed in the top quartile in EFOR, EAF, and NCF. This validates Big Rivers' assessment of the condition of the generating units during its due diligence prior to the Unwind Transaction.

More specifically, in a five year benchmarking study completed in August 2012, for the period **from April 2007 through March 2012**, the performance statistics for Big Rivers' units were in the best quartile for the units in its peer group. For the comparative period, the performance metrics for Big Rivers' units compared to the peer group are as follows:

Big Rivers Units		**Peer Group Best Quartile**	
EFOR	4.18%	EFOR	4.55% (lower is better)
EAF	90.07%	EAF	88.70% (higher is better)
NCF	81.55%	NCF	78.24% (higher is better)

In a one year comparison **from April 2011 through March 2012**, Big Rivers' units performed slightly better against the same peer group:

Big Rivers Units		**Peer Group Best Quartile**	
EFOR	3.69%	EFOR	3.84% (lower is better)
EAF	92.92%	EAF	92.04% (higher is better)
NCF	82.29%	NCF	76.15% (higher is better)

Thus, as this NERC GADS data demonstrates, the reliability of Big Rivers' generating facilities compares quite favorably to others in the industry at this juncture.

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. The Wilson Unit outage that was scheduled for September 26, 2009, through November 16, 2009, and the HMP&L Station Two Unit Two outage that was scheduled from April 3, 2010, through April 23, 2010, were the only outages completed as scheduled. Exhibit Berry-1 compares the planned outage schedule at closing of the Unwind Transaction against planned outages that have been completed and the outages that are currently scheduled through 2014. Exhibit Berry-1 also illustrates the change in scheduled maintenance outage days for each unit and for the fleet as a whole.

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. Ms. Billie Richert describes in more detail in her testimony the requirements of Big Rivers' loan agreements and the consequences if Big Rivers does not satisfy those requirements.

Due to the depressed economy before and since the closing of the Unwind Transaction, load demand on the Big Rivers system was down, off-system sales volumes were low, and wholesale market prices were down. As a result, Big Rivers' off-system sales revenues were depressed, and Big Rivers has had to reduce expenses to meet its minimum MFIR obligation.

In 2010, Big Rivers' implemented corporate-wide cost-cutting measures, but after exhausting its options to reduce non-maintenance expenses, the only remaining option for Big Rivers to achieve the magnitude of expense reductions it needed to meet its MFIR obligation was to defer planned maintenance outages. As Big Rivers noted in the 2011 Rate Case, between November 1, 2009 and October 31, 2010, Big Rivers deferred $3,866,966 of planned plant outage maintenance expense. When it became apparent the wholesale power market was not returning to previous levels anytime soon, Big Rivers also began preparing a rate case toward the end of 2010 to help assure it would earn sufficient future revenue to perform acceptable levels of maintenance and meet its debt covenants.

Big Rivers filed its rate application in the 2011 Rate Case to increase its base rates to offset a revenue deficiency of approximately $39.3 million, which included proposed *pro forma* adjustments to increase both planned plant outage expense and plant non-outage operations and maintenance ("O&M") expense. Big Rivers sought to make clear throughout that case that, although it was specifically seeking to include approximately $53.2 million for plant maintenance expense in its rates ($38.8 million for non-outage O&M expense plus $14.4 million for planned plant outage expenses), "....even if Big Rivers receives the full amount of the requested adjustments relating to maintenance costs, if it does not receive the full increase it is seeking, the only option available to Big Rivers to meet the required [MFIR] and maintain credit ratings as required in its long-term debt agreements would be to reduce plant maintenance, which would have an adverse impact on reliability and ultimately increase costs to Big Rivers."[1]

On page 15, lines 2 through 12 of his Direct Testimony in the 2011 Rate Case, Mr. Mark A. Bailey, Big Rivers' President and Chief Executive Officer, explained, "Without the additional revenue requirement associated with pro forma adjustment, Big Rivers will be required to reduce expenditures in order to meet its MFIR and maintain credit ratings as required in its long-term debt agreements. If it is not granted an adequate revenue increase in this proceeding, the only option available to Big Rivers to meet its MFIR requirements will be to reduce plant maintenance, which would have an adverse impact on reliability." In addition, on page 1, lines 10 through 16 of Big Rivers' response to Item 2 of the Commission Staff's Second Request for Information, dated April 1, 2011, in the 2011 Rate Case, Mr. Bailey noted, "If however, any of the major assumptions in the 2011 Budget do not materialize, additional cost cutting or maintenance deferrals will be employed to ensure Big Rivers maintains at least a 1.10 MFIR. For example, the 2011 Budget assumes an average off-system sales price of $41.81 per MWh. If the actual average off-system sales price for 2011 is materially less, Big Rivers will need to employ other strategies, principally

[1] See page 4, lines 15 through 19, of the Direct Testimony of Mr. Robert W. Berry in Case No. 2011-00036, which was filed on March 1, 2011.

additional cost cutting and cost deferral, to ensure the minimum required MFIR is achieved."

In its November 17, 2011, Order in the 2011 Rate Case ("the November 17 Order"), the Commission granted Big Rivers an annual revenue increase of only $26,744,776, ($12,744,776 less than Big Rivers' original request of $39,324,089). Big Rivers filed for rehearing of certain elements of the November 17 Order, and the rehearing is still pending. 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.

The depressed off-system market continues, and as such, Big Rivers still needs additional revenue to continue to perform the maintenance necessary to prudently maintain its generating units on an ongoing basis while still meeting the financial requirements described in the Direct Testimony of Ms. Billie J. Richert.

Thus, Big Rivers had no choice but to reduce expenses in 2010, 2011, and 2012 to ensure it achieved the minimum MFIR required by its loan agreements. Although Big Rivers reduced expenses in all non-maintenance expense categories as far as reasonably possible while still meeting its obligation to safely deliver reliable, low cost wholesale power, these reductions were insufficient, leaving maintenance as the only remaining area where expense reductions of the magnitude required could be made. As discussed below, this problem will be magnified substantially when the Century contract terminates on August 20, 2013, as the amount of the revenue deficiency associated with the Century contract termination is simply too large for Big Rivers to make up through cost cutting initiatives. If Big Rivers does not achieve the full amount of the rate increase it is seeking in this proceeding, it will face an ever increasing risk of major unplanned outages due to having to continue to defer maintenance activity in addition to being in serious danger of defaulting on its loan obligations.

Q Do Big Rivers' credit agreements impose any obligation on Big Rivers regarding maintenance of its facilities?

A. Yes. Section 13.7 of the Indenture contains a covenant relating to the maintenance of properties. Failure to comply is a covenant default under Section 8.1 C of the Indenture. Section 4.13 of the RUS Loan Contract requires that Big Rivers maintain and preserve its System in compliance in all material respects with the provisions of the Indenture, RUS Regulations, all applicable Laws and Prudent Utility Practice. Big Rivers' credit agreements with CFC and CoBank generally require compliance with the Indenture obligations. In addition to Big Rivers' interest in properly maintaining its facilities, it also must assure compliance with the obligations in its credit agreements to maintain the assets that secure its senior debt.

Q. How do the off-system sales market prices in the 2013 and 2014 budgets filed in this case compare to the 2011 and 2012 actual off-system sales market prices?

A. The budgeted off-system sales market prices for 2013 and 2014 are [redacted]/MWh and [redacted]/MWh, respectively, compared to the 2011 and 2012 actual experienced off-system sales price of [redacted]/MWh and [redacted]/MWh[2], respectively. The table below compares the 2013 and 2014 budgeted off-system sales price filed in this case to the actual experienced off-system sales price for 2011 and 2012.

Budget vs. Actual			**Budgets**	
	2011	**2012**	**2013**	**2014**
Budget Wholesale $/MWh	[redacted]	[redacted]	[redacted]	[redacted]
Actual Wholesale $/MWh	[redacted]	[redacted]		

Q. Since the Big Rivers generating units have performed so well since the Unwind Transaction, can Big Rivers continue with similar levels of scheduled outages and maintenance activities?

A. No. If Big Rivers continues with the previous three years' level of scheduled outages and maintenance activities, the condition of the generating units will deteriorate, Big Rivers will experience increased forced outages, repair costs will increase since they will be done on an emergency basis rather

[2] 2012 Actual value is based on the 10/2 forecast, i.e. Jan-Oct actual data and Nov-Dec forecast data.

than on a planned basis, and since forced outages cannot be planned to take advantage of market conditions, Big Rivers' purchased power costs will likely increase and its ability to generate off-system sales revenues will decrease. All of these factors together could be devastating to Big Rivers' financial position since its margins historically have been derived almost exclusively from off-system sales. Thus, if Big Rivers continues to defer maintenance activities, Big Rivers' mission to safely deliver low cost, reliable wholesale power to its members could be compromised.

Q. **Does Big Rivers have plans for any significant planned maintenance outages at its generating plants in the near future?**

A. Yes. Over the next three years, Big Rivers plans to perform major maintenance on all of its units, due in large part to the outage deferrals in 2010, 2011, and 2012. [redacted] By the beginning of 2016, the previously deferred planned maintenance is scheduled to be completed and all units will be back on their optimal outage rotation frequency.

There are no planned outages for the Wilson Station in the current plan, due to the budgeted layup of the plant that I discuss in further detail later in my testimony.

Q. Is it possible to shift some of the expenses to levelize the spending?

A. Yes. Looking forward to the next planning period, Big Rivers' production staff has assessed the condition of each unit in the fleet individually, and evaluated the risks associated with deferred planned maintenance, to adjust the future outage schedule to levelize annual spending and unit outage hours across the period. So long as Big Rivers receives the full amount of the increase it is seeking in this proceeding, by the beginning of 2016, Big Rivers expects to have all deferred maintenance completed and have all the units back on a maintenance outage frequency that is consistent with prudent utility operation on a long-term basis.

Q. What steps is Big Rivers taking to ensure the reliable, safe, and economic operation of its generation facilities on a future basis?

A. Outage planning is an important part of Big Rivers' reliability strategy. Planners at each station use the Big Rivers' outage planning process manual to ensure optimum results from unit down time. Big Rivers anticipates more than [redacted] of planned outage maintenance at an estimated cost of approximately [redacted] over the next four years. By the beginning of 2016, the maintenance work that was deferred during 2010, 2011, and 2012 is scheduled to be completed. Big Rivers also expects to spend more than $212 million in asset replacement and capital improvements over the next four years to enhance the reliability and efficiency of its power plants. These actions are necessary for Big Rivers to continue its trend of reliable, safe, and economic generation portfolio performance.

Q. If Big Rivers plans to spend approximately [redacted] dollars over the next four years on outage maintenance, how much does it plan to spend on routine non-outage operating and maintenance fixed departmental expense ("FDE")?

A. Over the next four years, Big Rivers expects to spend [redacted] on routine non-outage O&M net of HMP&L's share of Station Two. Exhibit Berry-2 shows Big Rivers' Production Department's fixed non-labor expenses broken down by outage and non-outage, by plant, and by year for 2013-2016.

Q. What are Big Rivers' plans for asset replacement and capital improvements at its power plants over the next four years?

A. Big Rivers' current capital work plan includes more than $212 million in capital improvements and asset replacement for its generating units that are necessary to keep the reliability of its fleet consistently within the top quartile of its peer group. Exhibit Berry-3 provides details of Big Rivers' production department's current capital work plan.

Q. Please explain how Big Rivers derived the planned outage expense included in the 2013 and 2014 budgets.

A. The scope and expense for planned outages are developed from a rigorous review of multiple reports and documents. These documents include, but are not limited to, previous post outage reports, previous third party inspection reports and recommendations, lists of known preventative maintenance ("PM") tasks and active work orders identifying known equipment malfunctions. Big Rivers also uses a computerized maintenance management system to plan and schedule preventive and predictive maintenance inspections to track the condition of its power plant equipment. These tasks include non-destructive testing and destructive metallurgical analysis of boiler components and high energy piping systems; machinery vibration monitoring and analysis; machine and equipment performance testing; digital thermography; oil sampling; and routine visual inspections. The results of these tests, inspections, and analyses are used to determine future needs and help construct the outage plans. Finally, each task that is selected for inclusion in an outage plan is individually reviewed, fairly estimated, and then incorporated in the appropriate outage budget.

Q. Please explain how Big Rivers derived the FDE included in the 2013 and 2014 budgets.

A. Big Rivers' non-outage O&M budget is developed through an arduous process of line by line review by each respective department. The variable O&M costs for fuel, pollution control equipment reagent, and ash and pollution control product disposal are dependent on generation volume which is calculated and supported by Big Rivers production cost model. The line items for FDE O&M costs are split into two categories, routine and special projects. The routine line items are generally calculated from historical costs by expenditure type, which are reviewed and adjusted based on projected activities year over year. The special project line items are mainly equipment planned maintenance overhauls and other repairs that are determined by Big Rivers' maintenance management program. Big Rivers uses a computerized maintenance management system to plan and schedule preventive and predictive maintenance inspections to track the condition of its power plant equipment. These tasks include non-destructive testing and destructive metallurgical analysis of boiler components and high energy piping systems; machinery vibration monitoring and analysis; machine and equipment performance testing; digital thermography; oil sampling; and routine visual inspections. The results of these tests, inspections, and analyses are used to determine future maintenance needs for the budget's special project lines. Each special project is then individually reviewed, fairly estimated, and then incorporated in the appropriate departmental budget.

IV. <u>CENTURY CONTRACT TERMINATION AND MITIGATION STEPS</u>

Q. What steps has Big Rivers taken to mitigate the effects of the Century contract termination?

A. As a result of Big Rivers receiving Century's Notice of Termination on August 20, 2012, Big Rivers has begun implementing its Load Concentration Mitigation Plan that was submitted under petition for confidential treatment to the Commission in Big Rivers' 2012 Environmental Compliance Plan case, Case No. 2012-00063.[3] Big Rivers has been implementing that plan since it received the Century notice. The plan calls for several steps.

First, the plan calls for Big Rivers to petition the Commission for a rate increase to help address any forecasted revenue shortfall stemming from Century's contract termination. Big Rivers has addressed this step in the instant filing and with the use of the fully-forecasted test period.

Second, the plan calls for Big Rivers to market all excess power when the market price is greater than marginal generation cost. From a forecast

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[3] See Big Rivers' Response to KIUC's Second Request for Information, dated June 22, 2012, Item 2-44(b).

standpoint, the market prices in MISO for the 2013 and 2014 time indicate that off-system sales margins will remain depressed relative to the levels that were described in the last rate case, so this step is not expected to be an effective mitigation method for the next few years.

Third, the plan calls for Big Rivers to idle or reduce generation when the market price does not support the cost of generating. Big Rivers plans to address this step by curtailing production by temporarily idling one of its power plants. I discuss this plan in more detail later in my testimony.

Fourth, the plan calls for Big Rivers to evaluate options to execute forward bilateral sales with counterparties, enter into wholesale power agreements, and/or participate in capacity markets. Big Rivers is actively exploring these alternatives. To that end, efforts are underway to find load replacement options for the 482 MW currently being utilized by Century. Big Rivers is following a multi-pronged approach, with Big Rivers' members focusing on economic development opportunities and Big Rivers' Energy Services Department working to find wholesale marketing opportunities for the power. So far, Big Rivers has provided formal responses to two Requests for Proposals ("RFPs") from other utilities. Big Rivers has informally initiated discussions with other potential counterparties, on a strictly confidential basis, to explore possible opportunities for Big Rivers to market its excess power.

To date, these efforts have not produced results; however, initiatives of this nature take time, and market conditions do change over time, so the present circumstances are not indicative of future outcomes. Big Rivers will continue its implementation of its Load Concentration Mitigation Plan, and will continue to seek other alternatives that are cost-effective, as appropriate.

Q. What is the expected timeframe for Big Rivers to secure any new contracts to replace the Century load?

A. Big Rivers expects that any of the efforts noted above will require three or four years to come to full fruition. Most new economic development opportunities – e.g., the attraction of a new industrial facility to a greenfield or brownfield site – often take six months for the outside party to finalize site selection, with another eighteen to twenty-four months for environmental assessment/mitigation, construction, and ramp-up to full load. The attraction of existing load ordinarily requires a distribution utility to give its current wholesale provider anywhere from two to five years notice of its intent to terminate its long term wholesale agreement. Even the option of responding to a future RFP for long term purchased power might require as much as six months for proposal evaluation and decision, with another six to twelve months for finalizing contracts, and with delivery commencing some period of time beyond that. At best, Big Rivers expects that any realistic alternative for finding sizable, long-term sales options will take at least three years, and perhaps more, to be fully realized.

Q. Given these lead times, what is Big Rivers' plan for reducing production-related costs, since Big Rivers will likely be unable to finalize sales contracts to replace the Century load by August 20, 2013?

A. Since it is likely that Big Rivers will be unable to replace the Century load before August 20, 2013, Big Rivers intends to continue to implement its Load Concentration Analysis and Mitigation Plan and curtail production to reduce the expense of full production in a depressed market. The current plan is to idle one of its generating plants to eliminate the variable cost of production and reduce the FDE cost to Big Rivers' members. In its 2013 budget, Big Rivers assumed Wilson Station will be idled. Big Rivers continues to evaluate a range of options to arrive at the most cost-effective alternative possible for Big Rivers' members. If a more cost-effective and viable alternative is identified, Big Rivers' members will benefit, and Big Rivers will pursue the appropriate method(s), consistent with the Smelter Agreements, to allow the net benefits to inure to its members.

Since Big Rivers received Century's Notice of Termination on August 20, 2012, Big Rivers has deferred backfilling all production vacancies in anticipation of a workforce reduction due to the potential idling of one of its generating stations. Big Rivers has only backfilled positions that could not physically be performed with overtime of its remaining staff. This has created a significant amount of overtime; however, it is Big Rivers belief this is a prudent approach to reduce the number of involuntary work force reductions after Century exits the system on August 20, 2013.

Q. Why did Big Rivers choose to idle Wilson Station in the budget?

A. As a transmission-owning member of MISO, Big Rivers must secure the approval of MISO for the layup of any generating station, to ensure that such an action does not have an adverse impact on the reliability of the transmission system. Because of the physical proximity of the Coleman station to Century's Hawesville facility, and given the possibility that Century could ultimately be purchasing power from the market, Big Rivers assumed that if the Century facility continues to operate in any substantial way on or after August 20, 2013, MISO would require Big Rivers to continue to operate the Coleman Station for system reliability reasons. Since no such proximity constraint applies to the Wilson Station, it is Big Rivers' belief that idling the Wilson Station will have less of a negative impact to the transmission system reliability, if the Century facility continues to operate in any substantial way on or after August 20, 2013.

Q. Will the production curtailment result in the loss of jobs at Big Rivers?

A. Big Rivers expects to reduce as many as ninety-two (92) positions as a result of the production curtailment due to termination of the Century contract. However, that will not be necessary if Big Rivers is able to replace the Century load or if the wholesale power market prices increase to the level greater than or equal to the cost savings afforded Big Rivers by idling the plant.

Q. Has Big Rivers developed an estimate of how much the Century contract termination contributes to the $74,476,120 revenue deficiency identified in this case?

A. Yes. Big Rivers estimates that the Century contract termination accounts for approximately $63 million of the $74.5 million revenue deficiency and requested rate increase in this case.

Note that the actual revenue deficiency calculation is based on forecasted margins and target TIER, as described in the testimonies of Ms. Billie J. Richert and Mr. John Wolfram. The estimate of the Century contract termination impact that I provide is intended to put the net effect of the Century contract termination on Big Rivers' revenue requirement into the proper perspective as a driver for the requested rate increase.

Q. How did Big Rivers determine the $63 million estimated impact of the Century contract termination?

A. Big Rivers started with Century's Gross Sales Margin (revenue less variable costs) and subtracted from that the estimated total reduction in the FDE budget resulting from the Wilson layup (including maintenance costs), the additional off-system net sales margins, and the associated reduction in MISO fees. This calculation is provided in Exhibit Berry-4.

Q. Can Big Rivers offset this estimated $63 million revenue shortfall by deferring production maintenance expenditures?

A. No. The revenue requirement impact of the Century contract termination far exceeds the entire annual budget for production maintenance. Big Rivers has no way to fully offset this revenue shortfall solely with cost cutting initiatives. The only way Big Rivers can make up the $63 million revenue shortfall related to the Century contract termination is to increase rates as proposed in this case.

Q. What will Big Rivers do if mitigation efforts succeed after new rates become effective?

A. Big Rivers' mission is to provide safe, reliable, low-cost power to its members. While the rate increase proposed in this case is aimed at mitigating one hundred percent of the revenue impact to Big Rivers resulting from the Century contract termination, Big Rivers is working very hard to ensure that the proposed increase is temporary in nature. As Big Rivers is successful in mitigating the adverse impacts of the Century contract termination, Big Rivers' members will benefit, and Big Rivers will pursue the appropriate method(s), consistent with the Smelter Agreements, to allow the net benefits to inure to its members.

V. MISO EXPENSES & REVENUES

Q. Please explain Big Rivers' decision to join MISO.

A. Big Rivers is required to satisfy the Contingency Reserve standard mandated by the North American Electric Reliability Corporation ("NERC"). The Contingency Reserve standard is an operational reliability requirement, and failure to satisfy its requirements can result in fines up to $1 million per day for each violation.

Prior to joining MISO, Big Rivers satisfied its Contingency Reserve obligations through reserve sharing agreements. In 2009, Big Rivers became aware that its then-current reserve sharing agreement would be terminated and that it would not be able to renew it or enter into a new agreement. Big Rivers commissioned Charles River Associates ("CRA") to conduct an economic assessment of the options available to Big Rivers to satisfy its Contingency Reserve requirements. The CRA analysis concluded that Big Rivers had no viable options for meeting its Contingency Reserve requirements other than with a stand-alone self-supply plan or by joining MISO. Joining MISO was by far Big Rivers' least-cost option for meeting its Contingency Reserve requirements.

Big Rivers was approved by MISO for membership in December 2009 and was fully integrated into MISO on December 1, 2010, following the approval by the Commission on November 1, 2010, in Case No. 2010-00043.

Q. Has Big Rivers incurred any incremental costs as a result of its MISO membership?

A. Yes. MISO operates three competitive markets and acts as a financial clearinghouse for market participants' electric energy supply, load, and financial transmission rights ("FTRs"). The three markets are referred to as the FTR Market, the Day-Ahead Energy Market, and the Real-Time Energy Market. The purpose of these markets is to facilitate competition between market participants, dispatch the least cost available generation resources, optimize the use of the transmission system, and provide market participants with the ability to hedge transmission congestion costs. In providing these Energy Market mechanisms, the Federal Energy Regulatory Commission ("FERC") permits MISO to recover the costs of providing these services from market participants.

Q. Please describe the MISO-related costs included in the budgets Big Rivers filed in this case.

A. Big Rivers included in its budgets a projection of all charges and credits associated with participation in all three MISO markets. Among these are administration fees, energy-related revenues and charges, transmission revenues and charges, FTR-related revenues and charges, and costs which MISO passes on to all market participants based on their activity within the markets.

Q. Are any of these costs included in Big Rivers' current rates?

A. Yes. In the 2011 Rate Case, Big Rivers requested and was granted a *pro forma* adjustment to recover an estimated $5.3 million in MISO administration fees. However, Big Rivers has and continues to incur the other MISO costs that are not presently recovered through its current rates.

Q. Why did Big Rivers only request recovery of the MISO administrative fees in the 2011 Rate Case, instead of requesting recovery of all the MISO charges?

A. At the time, Big Rivers had limited experience as a fully-integrated member in the MISO market; therefore, Big Rivers chose to wait to request recovery of charges from the Commission until it had the opportunity to better understand the costs and benefits to its members of MISO market participation.

Q. How are the MISO administrative fees included in the budgets filed in this case?

A. Big Rivers included in the budgets filed in this case projected MISO administrative fees based on the output of generation and consumption of load reflected in the production cost model used for this case. Big Rivers reduced its projection of MISO administrative fees to reflect the reduction in load caused by Century's contract termination and the reduction in generation caused by the lay-up of the Wilson Station.

Q. How are the MISO energy-related revenues and charges included in the budgets filed in this case?

A. Big Rivers included a projection of the energy-related charges and credits from the MISO market through the outputs of the production cost model. The production cost model projects Big Rivers' net hourly position (power excess or deficit) throughout the year and estimates Off-System Sales revenues and Member purchases accordingly.

Q. How are the MISO transmission revenues and charges included in the budgets filed in this case?

A. Big Rivers included MISO transmission revenues and charges in the forecast using a combination of historical values and MISO projected costs for the future (where available).

Q. How are the FTR-related revenues and charges included in the budgets filed in this case?

A. Big Rivers used historical values to estimate the revenues and charges associated with the MISO FTR Market settlements. Adjustments were made to reflect the expected impact of Century's contract termination.

Q. How are the credits/charges which MISO passes on to all market participants based on their activity within the markets included in the budgets filed in this case?

A. Big Rivers used historical values to estimate the non-administrative, non-transmission-related credits and charges MISO passes on to all market participants based on their market activity. The net cost is embedded within the projected revenues for off-system sales.

Q. Do the costs noted above represent discretionary spending on the part of Big Rivers?

A. No. The expenses and revenues that I mentioned result from Big Rivers' membership in MISO. They are not discretionary on the part of Big Rivers; Big Rivers is required to pay these charges pursuant to the FERC-approved

MISO tariffs. These costs should be accepted as part of the budgets used for ratemaking purposes in this proceeding.

VI. OTHER ENERGY SERVICE RELATED EXPENSES

Q. Please describe the ACES fee included in Big Rivers' forecast.

A. Big Rivers has been a member-owner of ACES, formerly known as ACES Power Marketing, since January 2003. ACES acts as Big Rivers' agent to assist in managing Big Rivers' energy portfolio through generation dispatch, hourly and term trading, origination, settlements, and FTR optimization. ACES also provides a suite of support services such as energy risk management, portfolio modeling, contract administration, and regulatory services. Big Rivers included $2,244,000 for the ACES fees in the budgets filed in this case. These fees are incurred pursuant to the bilateral agreement between Big Rivers and ACES.

Q. How are the TVA transmission expense and associated revenues included in the budgets filed in this case?

A. Big Rivers owns the rights to a 100 MW transmission path across the TVA transmission system. Big Rivers budgeted $2,448,000 for the TVA transmission fees based on the historical charges from TVA and budgeted projected revenues of [redacted] in the test period projected based on realized revenues from 2012.

VII. <u>MODELING AND LOAD FORECAST</u>

Q. What is your role in the development of load forecasts and production cost models that are used in the development of Big Rivers' budgets?

A. Energy Services personnel under my direction worked with GDS Associates, Inc., in the preparation of the load forecast that was used in the development of Big Rivers' budgets. The load forecast is discussed in detail in the Direct Testimony of Ms. Lindsay N. Barron. Energy Services and Production personnel under my direction also worked with ACES on the production cost modeling that was used as an input to the Big Rivers financial model.

Q. How did Big Rivers develop the production cost modeling that is used in the budget development process?

A. Big Rivers contracts with ACES to run the production cost models that are used in the Big Rivers financial model. (The Big Rivers financial model is described in the Direct Testimony of Mr. Travis A. Siewert.) Big Rivers provides ACES with generating unit operating characteristics (e.g., capacity, heat rates, outage rates, ramp rates, etc.), fuel contract information, demand and energy forecasts, and other production cost model input data. ACES develops price forecasts for energy and emission allowances. ACES runs its Planning And Risk ("PAR") model, which models the MISO energy markets by (i) dispatching Big Rivers' generation units economically based on Locational Marginal Prices ("LMPs") and (ii) purchasing from the MISO market at an LMP to meet Big Rivers' load. ACES then provides Big Rivers with PAR model output data that is incorporated by Mr. Siewert into the Big Rivers financial model.

VIII. FILING REQUIREMENTS FROM 807 KAR 5:001

Q. Have you reviewed the answers provided in Tabs 1-62, which address Big Rivers' compliance with forecasted period filing requirements under 807 KAR 5:001 and its various subsections?

A. Yes. I have, and I hereby incorporate and adopt those portions of Tabs 1-62 for which I am identified as the sponsoring witness.

IX. CONCLUSION

Q. Do you have any closing comments?

A. Yes. Big Rivers is requesting only the revenue it needs to continue to operate and maintain its plants prudently in the future, maintain the value of its generating assets, and meet its financial covenants. Big Rivers estimates that approximately $63 million of its $74.5 million revenue deficiency is related to the Century contract termination. The total revenue deficiency far exceeds the entire annual budget for production maintenance, and while Big Rivers plans to reduce expenses, it has no way to offset this revenue deficiency with cost cutting initiatives. Big Rivers must have the full amount of its requested increase to totally overcome these factors. This will allow Big Rivers to operate in a manner that is in the best interest of all its members and their retail member customers and still satisfy the requirements of its loan agreements.

Q. Does this conclude your testimony?

A. Yes.

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2012-00535

VERIFICATION

I, Robert W. Berry, verify, state, and affirm that I prepared or supervised the preparation of my testimony filed with this Verification, and that testimony is true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Robert W Berry

Robert W. Berry

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Robert W. Berry on this the 9 day of January, 2013.

Joy P. Wright

Notary Public, Ky. State at Large
My Commission Expires________

Notary Public, Kentucky State-At-Large
My Commission Expires: July 3, 2014
ID 421951

Big Rivers Electric Corporation
Case No. 2012-00525
Unit Outages Since Closing

	Unit	Net MW	2009	Change	2010	Change	2011	Change	2012	Change	2013	Change	2014	Change	Overall Change
Outage Schedule at Closing	Coleman 1	150					February - 25 Days				[redacted]				
Current Outage Schedule	Coleman 1							(25)							
Outage Schedule at Closing	Coleman 2	138			March - 25 Days										
Current Outage Schedule	Coleman 2				October - 28 Days	3									
Outage Schedule at Closing	Coleman 3	155							May - 32 Days						
Current Outage Schedule	Coleman 3									(32)					
Outage Schedule at Closing	Coleman FGD						March - 14 Days								
Current Outage Schedule	Coleman FGD				October - 14 Days	14		(14)							
Outage Schedule at Closing	Green 1	231			April - 28 Days				March - 21 Days						
Current Outage Schedule	Green 1				May - 10 Days	(18)	October - 28 Days	28		(21)					
Outage Schedule at Closing	Green 2	223					March - 28 Days								
Current Outage Schedule	Green 2						November - 10 Days	(18)							
Outage Schedule at Closing	Henderson 1	153					May - 32 Days								
Current Outage Schedule	Henderson 1						April - 12 Days	(20)	March - 32 Days	32					
Outage Schedule at Closing	Henderson 2	159			April - 21 Days				March - 49 Days						
Current Outage Schedule	Henderson 2				April - 21 Days	0			February - 13 Days	(36)					
Outage Schedule at Closing	Reid 1	65			May - 21 Days										
Current Outage Schedule	Reid 1				October - 7 Days	(14)									
Outage Schedule at Closing	Wilson	417	September - 49 Days		February - 7 Days		September - 28 Days		February - 7 Days						
Current Outage Schedule	Wilson		September - 49 Days	0	November - 7 Days	0	March - 7 Days	(14)	March - 14 Days	7					
Total Changes				0		(15)		(63)		(50)					

Outage Schedule at Closing

Current Outage Schedule

For 2016 and beyond we expect to return to our normal schedule

Big Rivers Electric Corporation
Case No. 2012-00525
Fully Forecasted Test Period
Production FDE Breakdown 2013 - 2016

Excludes HMP&L's Share
Excludes Internal Labor

Plant	Year	Outage $ FDE	Routine $ FDE	Total O&M
Wilson	2013 Plan	[redacted]	[redacted]	[redacted]
Wilson	2014 Plan	[redacted]	[redacted]	[redacted]
Wilson	2015 Plan	[redacted]	[redacted]	[redacted]
Wilson	2016 Plan	[redacted]	[redacted]	[redacted]
Coleman	2013 Plan	[redacted]	[redacted]	[redacted]
Coleman	2014 Plan	[redacted]	[redacted]	[redacted]
Coleman	2015 Plan	[redacted]	[redacted]	[redacted]
Coleman	2016 Plan	[redacted]	[redacted]	[redacted]
Green	2013 Plan	[redacted]	[redacted]	[redacted]
Green	2014 Plan	[redacted]	[redacted]	[redacted]
Green	2015 Plan	[redacted]	[redacted]	[redacted]
Green	2016 Plan	[redacted]	[redacted]	[redacted]
R/SII	2013 Plan	[redacted]	[redacted]	[redacted]
R/SII	2014 Plan	[redacted]	[redacted]	[redacted]
R/SII	2015 Plan	[redacted]	[redacted]	[redacted]
R/SII	2016 Plan	[redacted]	[redacted]	[redacted]

		Outage $	Routine $	Total
BREC	2013 Plan	[redacted]	[redacted]	[redacted]
BREC	2014 Plan	[redacted]	[redacted]	[redacted]
BREC	2015 Plan	[redacted]	[redacted]	[redacted]
BREC	2016 Plan	[redacted]	[redacted]	[redacted]
	Total	[redacted]	[redacted]	[redacted]

Big Rivers Electric Corporation
Case No. 2012-00525
Fully Forecasted Test Period
Summary of Production Capital Construction Budget 2013-2016

Plant	Year 2013
Coleman	[redacted]
Central Machine Shop	
Green	
Reid/HMP&L	
Wilson	
HAPS/MATS*	
Total**	

Plant	Year 2014
Coleman	[redacted]
Central Machine Shop	
Green	
Reid/HMP&L	
Wilson	
HAPS/MATS*	
Total**	

Plant	Year 2015
Coleman	[redacted]
Central Machine Shop	
Green	
Reid/HMP&L	
Wilson	
Total**	

Plant	Year 2016
Coleman	[redacted]
Central Machine Shop	
Green	
Reid/HMP&L	
Wilson	
Total**	

Grand Total** $ 212,494,990

*Capitalized interest is included
**Excludes the City's Share of SII

Big Rivers Electric Corporation
Case No. 2012-00535
Revenue Requirement due to Century Exit

Century Gross Sales Margin (Revenue less Variable Cost)	**92,397,332**

Wilson Lay-Up Savings (2014-2015 Annual Average)

FDE Non-Labor	[redacted]
FDE Labor	
Total FDE Budget	
Less Lay-Up cost	[redacted]
Less Retained Big Rivers Labor	
Total FDE Budget Reduction	[redacted]

Addl. OSS Net Sales Margin	[redacted]
Reduction in MISO Expenses	**2,079,728**
Net Revenue Requirement Due to Century Exit	**63,028,536**

Note: Laying up Wilson does not eliminate all fixed costs. Items such as Depreciation, Interest, Property Tax, and Property Insurance remain.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

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

DIRECT TESTIMONY

OF

DAVID G. CROCKETT
VICE PRESIDENT, SYSTEM OPERATIONS

ON BEHALF OF

BIG RIVERS ELECTRIC CORPORATION

FILED: January 15, 2013

DIRECT TESTIMONY
OF
DAVID G. CROCKETT

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DIRECT TESTIMONY
OF
DAVID G. CROCKETT

I. INTRODUCTION

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

A. My name is David G. Crockett. I am employed by Big Rivers Electric Corporation ("Big Rivers"), 201 Third Street, Henderson Kentucky, 42420, as its Vice President, System Operations. I have held this position since January 2006. Prior to 2006, I held several positions in the Engineering Department, and in 1998, assumed responsibility for the Energy Control Department as Manager over both areas. Altogether, I have been employed by Big Rivers for a total of 40 years. I am a registered Professional Engineer in Kentucky. I graduated in 1972 from the University of Kentucky with a Bachelor of Science degree in Electrical Engineering.

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

A. Yes. I most recently testified in the case relating to Big Rivers joining the Midwest Independent Transmission System Operator, Inc. ("MISO"), Case No. 2010-00043, in Big Rivers' last rate case, Case No. 2011-00036 (the "2011 Rate Case"), and in Big Rivers' recent Environmental Compliance Plan case, Case No. 2012-00063.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to: (i) provide an overview of the Big Rivers transmission system; (ii) describe how Big Rivers derived the transmission capital and transmission operation and maintenance ("O&M") expense included in the budget filed in this case; and (iii) describe the status of certain transmission projects.

III. TRANSMISSION SYSTEM OVERVIEW

Q. Please describe the Big Rivers transmission system.

A. Big Rivers owns, operates, and maintains a 1,266-mile transmission system and 22 substations. Twenty-two interconnects link the Big Rivers system with seven neighboring utilities.

Q. Is Big Rivers now a transmission-owning member of MISO?

A. Yes. Big Rivers became fully integrated as a transmission-owning member of MISO effective December 1, 2010.

Q. How would you characterize the overall experience of Big Rivers as a MISO member to date?

A. Big Rivers' membership in MISO has been successful. Big Rivers joined MISO because it was the least-cost means available to enable Big Rivers to satisfy its Contingency Reserve obligations and avoid potential penalties for non-compliance from the North American Electric Reliability Corporation ("NERC") and SERC Reliability Corporation ("SERC"). Through its integration into MISO and the benefits available from the MISO market operation, Big Rivers has been able to fully comply with the NERC Contingency Reserve requirement and avoid non-compliance penalties. Big Rivers has also realized benefits from a reduction in transmission congestion since joining MISO. This has resulted in improvements in Big Rivers' ability to both purchase and sell power off-system.

IV. <u>TRANSMISSION CAPTIAL AND FIXED DEPARTMENTAL EXPENSE (FDE) O&M</u>

Q. Please explain how Big Rivers derived the transmission capital costs included in the budgets filed in this case.

A. The development of the transmission capital budgets filed in this case was a collaborative effort involving both the engineering staff and the transmission staff. Engineering supervision provided estimates of the 2013 and 2014 costs anticipated to be incurred on certain transmission line and substation construction projects identified in Big Rivers' latest three-year construction work plan. The capital budgets also included estimates of the 2013 and 2014 costs for recommended communication system addition or replacement projects. These project cost estimates for calendar years 2013 and 2014 were developed from the most up-to-date implementation schedules available as input in the budget preparation process. In addition, transmission supervision provided estimates of 2013 and 2014 costs for capital construction projects developed from their transmission maintenance program recommendations and schedules. They also provided estimates of 2013 and 2014 costs for capital equipment purchases involving little or no labor expense. Capitalized interest was calculated by the budget accounting staff on the overall capital budget. Engineering supervision provided the budget department staff with labor estimates based on both the 2013 and 2014 capital project requirements and the historical capitalized labor amounts. For information regarding Big Rivers' overall internal labor budget development process, please reference the Direct Testimony of Ms. DeAnna M. Speed. The total transmission capital construction budget estimate for 2013 is less than the budget estimate for 2012, and the estimate for 2014 is less than the estimate for 2013. However, variability in the number, timing, and scope of the required capital construction projects and capital equipment from year to year make a comparison of transmission capital annual budgets of limited significance.

Q. Please explain how Big Rivers derived the fixed departmental expenses ("FDE") for transmission included in the budgets filed in this case.

A. The transmission FDE included in the budgets filed in this case was also a result of collaborative efforts by a number of departments in the Big Rivers organization. The transmission maintenance FDE was derived in large part from estimates of the costs of planned maintenance program activities for 2013 and 2014 as developed by transmission supervision. The maintenance FDE includes all materials, outside contractor services, and vehicle expenses anticipated to be required to complete the maintenance activities for the budget years. Transmission supervision also developed the transmission operation FDE in large part from estimates of the costs of planned operational activities for the budget years. The operation FDE included all materials, outside contractor services, and vehicle expenses anticipated to be required to complete the planned operational activities for the budget years. The transmission operation FDE in the budget also included all costs anticipated for 2013 and 2014 associated with operation of the 24x7 system operations center. For additional information regarding Big Rivers' overall labor budget development process, please reference the Direct Testimony of Ms. DeAnna M. Speed.

Q. Are you also explaining how Big Rivers derived the MISO-related costs included in the budgets filed in this case?

A. No. Mr. Robert W. Berry describes the MISO-related costs included in the budgets.

V. STATUS OF TRANSMISSION IMPROVEMENTS

Q. Did the Commission grant Big Rivers a Certificate of Public Convenience and Necessity in Case No. 2007-00177 for the construction of a transmission line that, together with other transmission system additions and improvements, are known now as the Phase 2 Transmission Projects?

A. Yes. Furthermore, in Case No. 2007-00455, Big Rivers committed to complete the construction of the Phase 2 Transmission Projects and "to advise the Commission and the Attorney General's Office on a timely basis of the date those transmission facilities become fully operational and of any material events related to the Big Rivers transmission system that impact Big Rivers' long-term ability to wheel excess power to its border for sale into other markets."[1]

Q. What is the purpose of the Phase 2 Transmission Projects?

A. The Phase 2 Transmission Projects were an essential part of Big Rivers' effort to mitigate the risks associated with providing electric service for Century Aluminum of Kentucky General Partnership ("Century") and Alcan Primary Product Corporation (together, the "Smelters"), which Big Rivers agreed to do as part of the transaction that was approved by the Commission in Case No. 2007-00455 (the "Unwind Transaction"). More

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[1] Order dated March 6, 2009, in Case No. 2007-00455, Appendix A, ¶ 22.

specifically, in the Unwind Transaction, Big Rivers entered into contracts to provide electric service to Kenergy Corp. ("Kenergy") for resale to the Smelters. Without the ability to export the Smelter load (850MW) and to sell that power into the market in the event both Smelters shut down, the risks of the Unwind Transaction were simply too great for Big Rivers and its members. The Phase 2 Transmission Projects were designed to enable Big Rivers to withstand the loss of the load of both Smelters by increasing the export capacity of the Big Rivers system to cover not only the 850 MW Smelter load but also the additional generating capacity that is available when the balance of Big Rivers' members' loads are at their lowest levels.

Q. Please describe the status of the Phase 2 Transmission Projects.

A. Big Rivers has completed or substantially completed all of the system improvements identified as the Phase 2 Transmission Projects except one. Big Rivers has entered into a construction work agreement with the Tennessee Valley Authority ("TVA") under which TVA will complete work on its system at an existing interconnection point with Big Rivers (Paradise switchyard), which encompasses the final project. TVA has indicated that this work will be completed in the 2014-2015 timeframe.

Q. Does Big Rivers currently have the capability to export the power that Big Rivers currently provides to Kenergy for service to Century?

A. Yes. Big Rivers currently has the capability to export the Century power in addition to the generating capacity that is available when the balance of Big Rivers' members' loads are at their lowest levels. The Phase 2 Transmission Projects, when complete, will simply allow Big Rivers to export even more power, or the equivalent energy of both Smelters.

Q. Does the fact that one of the Phase 2 Transmission Projects is still in progress adversely impact Big Rivers' ability to export power?

A. No. Big Rivers can reconfigure its system today on a temporary basis to achieve the desired capability to export the entire 850MW of both Smelters until the TVA system improvements can be completed.

Q. Has Big Rivers analyzed the physical feasibility of exporting the Smelter power since the Unwind Transaction proceeding?

A. Yes. Big Rivers requested a MISO assessment of transfer capability from the Big Rivers transmission zone into other MISO zones and TVA, assuming the termination of all Smelter load (850 MW). The July 11, 2011, results of the MISO study indicate that the Big Rivers transmission system has a transfer capability in the year 2016 (after the Phase 2 Transmission Projects are complete) well in excess of the 850 MW currently provided to both of the Smelters.

VI. FILING REQUIREMENTS FROM 807 KAR 5:001

Q. Have you reviewed the answers provided in Tabs 1-62, which address Big Rivers' compliance with forecasted period filing requirements under 807 KAR 5:001 and its various subsections?

A. Yes. I have, and I hereby incorporate and adopt those portions of Tabs 1-62 for which I am identified as the sponsoring witness.

VII. CONCLUSION

Q. What are your conclusions and recommendations to the Commission in this proceeding?

A. From a transmission standpoint, Big Rivers is meeting its obligations to provide safe and reliable transmission service to its customers. Big Rivers is satisfying its NERC and SERC reliability obligation and is working to optimize its membership in MISO. Big Rivers is also satisfying its commitments to the Commission regarding the Phase 2 Transmission Projects. Big Rivers needs sufficient rates not only to be able to continue to offer safe and reliable transmission service, but also to perform all of the other functions necessary to provide low cost power to its members. Consequently, and as further explained in the Direct Testimonies of Mr.

Mark A. Bailey and Mr. Robert W. Berry, the Commission should approve the full amount of the rates proposed by Big Rivers.

Q. Does this conclude your testimony?

A. Yes.

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES CASE NO. 2012-00535

VERIFICATION

I, David G. Crockett, verify, state, and affirm that I prepared or supervised the preparation of my testimony filed with this Verification, and that testimony is true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

David G. Crockett
David G. Crockett

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by David G. Crockett on this the 9th day of January, 2013.

Paula Mitchell
Notary Public, Ky. State at Large
My Commission Expires 1-12-17

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

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

DIRECT TESTIMONY

OF

DEANNA M. SPEED
MANAGER, BUDGETS

ON BEHALF OF

BIG RIVERS ELECTRIC CORPORATION

FILED: January 15, 2013

DIRECT TESTIMONY
OF
DEANNA M. SPEED

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DIRECT TESTIMONY
OF
DEANNA M. SPEED

I. INTRODUCTION

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

A. My name is DeAnna McCormick Speed. My business address is 201 Third Street, Henderson, Kentucky, 42420. I am employed by Big Rivers Electric Corporation ("Big Rivers") as its Manager-Budgets.

Q. Please describe your job responsibilities.

A. I report to the Vice President – Accounting and Interim Chief Financial Officer. My responsibilities primarily consist of managing the Big Rivers' budget process, managing the monthly variance and forecast reporting process, managing the Authorization for Investment Proposal ("AIP") process for capital purchases, and managing other ad hoc analyses.

Q. Briefly describe your education and work experience.

A. I have held my current position since July 2009 upon the closing of the transaction that unwound Big Rivers' 1998 lease with E.ON U.S., LLC and its affiliates (the "Unwind Transaction"), described in Case No. 2007-00455. Prior to the closing of the Unwind Transaction, I was employed by Western Kentucky Energy Corporation ("WKE") for 11 years as a Budget Analyst and as Manager of Budgets. I originally joined Big Rivers in the finance and accounting department in 1994. I earned a Bachelor of Science degree in accounting from Western Kentucky University. I hold a Certified Public Accountant ("CPA") license in the state of Kentucky. A summary of my professional experience is provided as Exhibit Speed-1.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is (i) to describe the process of developing Big Rivers' annual budget and financial plan, including a description of the roles and contributions of various Big Rivers' departments in the process, (ii) to describe the budget results for 2013 and 2014, and (iii) to sponsor certain filing requirements from 807 KAR 5:001.

Q. Are you sponsoring any exhibits?

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

1. Exhibit Speed-1 Qualifications of DeAnna M. Speed;
2. Exhibit Speed-2 Overview of Budget Process: Original; and
3. Exhibit Speed-3 Overview of Budget Process: Revised.

III. BUDGET DEVELOPMENT PROCESS

Q. What is your role in the overall budgeting process at Big Rivers?

A. I am responsible for overall coordination of the corporate budgeting process. This involves distributing budget instructions, milestones, and other information to departments throughout the organization and ensuring that all of the necessary steps in the budgeting process are completed. An overview of the budget process and timeline is provided in Exhibit Speed-2. The budget development process itself has numerous steps that take several months to complete. When the proposed budget is complete and approved by senior management, I prepare materials for the Big Rivers Board of Directors and present the budget and financial plan to them for their review and approval.

Q. What tools does Big Rivers utilize to manage and support the budget development process?

A. Big Rivers uses Hyperion, a budgeting and reporting software application, to support a portion of the budget development process. Certain data sets are entered directly to Hyperion for budget development purposes. Big Rivers also developed a spreadsheet model, referred to as the Big Rivers financial model, which is used to compile in a single source the information related to production costs, long term debt, revenues by rate class, and other specific Big Rivers' operating and financial parameters. This is described in detail in the Direct Testimony of Mr. Travis A. Siewert.

Q. Please provide an overview of the process that Big Rivers follows each year when developing its annual budget.

A. In broad terms, Big Rivers produces its annual budget by combining several sources of information into the financial model. The data sets include labor-related items (e.g., headcount, wages and salaries, overtime, overheads) and fixed departmental expenses (e.g., plant maintenance, professional services) that are calculated and distributed by Rural Utility Service ("RUS") account in the Hyperion budget application. The data sets also include variable costs from production cost modeling, fuel costs, off-system sales, Big Rivers' share of Henderson Municipal Power & Light ("HMP&L") costs, depreciation, capitalized interest, property tax, property insurance, total revenues and other items. Many of these data sets are first developed independently and from different sources. The budget department staff analyze various data sets to ensure reasonableness. Once the preliminary data is available, that data is incorporated into the financial model to develop a comprehensive preliminary budget for the company. Financial metrics are then assessed to determine if any adjustments to the preliminary budget are required in order for Big Rivers to meet its debt covenants or other requirements. This stage of the process is iterative, with several rounds of review by budget analysts, department managers, and the senior management team. After these reviews, Big Rivers provides a draft budget to two smelters ("the Smelters") for their information pursuant to their contractual agreements. Once a proposed budget is reviewed by senior management, Big Rivers presents the proposed budget to the Board of Directors for their review and approval. After the Board approves the budget, Big Rivers provides the approved budget to the Smelters, National Rural Utilities Cooperative Finance Corporation ("CFC") and to CoBank per the requirements of the agreements with each entity.

Q. What are the main data sets input to the budget, and who is responsible for developing each?

A. The budget department facilitates the development of the data sets with appropriate parties. The main data sets that comprise the budget process include the following:

1) Labor and Labor-Related Information – the headcount, wage and salary rates, overtime factors, and benefits values determined by a combination of department managers, administrative services, and payroll staff are calculated in Hyperion;

2) Capital items – the anticipated capital expenditures developed by a team of individuals from Production, System Operations, Information Services, and/or other departments;

3) Production-related variable costs – the non-fuel costs specified in existing contracts that are provided by Big Rivers to ACES for inclusion in the production cost modeling and incorporated in to Big Rivers' financial model;

4) Fuel costs – the costs for fuel specified in long-term contracts that are provided by Big Rivers' Fuel department to ACES for inclusion in the production cost modeling;

5) Load Forecast – the projections of demand and energy for Big Rivers' members that are provided by Big Rivers' Energy Services staff to ACES for inclusion in the production cost modeling;

6) Off-System Sales – the volumes and prices associated with off-system sales as determined by the output of the production cost model performed by ACES and incorporated into the Big Rivers financial model;

7) Energy Services-related costs – ACES costs, Midwest Independent Transmission System Operator, Inc. ("MISO") administrative costs and other costs and revenues developed by Energy Services;

8) Other non-member revenues – interest income and other items that reduce the revenue requirement developed in the Big Rivers financial model;

9) Big Rivers allocation from HMP&L – portion of costs allocated by HMP&L pursuant to Big Rivers' agreements with the City of Henderson, developed by the Budget department staff;

10) Interest on long-term debt and amortization of debt expense, developed by the Finance department staff;

11) Big Rivers' Share of Station Two[1] – the portion of costs for HMP&L Station Two related expenditures borne by Big Rivers, pursuant to Big Rivers' agreements with the City of Henderson and calculated in Hyperion;

12) Costs for depreciation, amortization, capitalized interest, property tax, property insurance, and other items developed by various internal accounting parties and incorporated into the Big Rivers financial model;

13) Member Revenues – the revenues from Big Rivers' members, calculated at the proposed rates in the Big Rivers financial model;

14) Amortization of certain deferred expenditures, developed by Budget department staff;

15) Line of credit fees ("LOC") and amortization of LOC fees, developed by Finance department staff;

16) Costs for Fixed Departmental Expense ("FDE") (e.g., plant maintenance, outside services, and other items) developed by the managers of various departments across Big Rivers in conjunction with the budget analysts.

I describe several of these data sets in greater detail below.

Q. How is the labor and labor-related budget developed?

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[1] Big Rivers operates Henderson Municipal Power & Light's Station Two and is allocated a portion of its capacity; see the Direct Testimony of Robert W. Berry.

A. The headcount totals are determined for each department by the department managers and submitted to the budget analysts. The headcount totals for the entire organization are reconciled to the organizational chart by the Manager-Budgets and the Vice President-Administrative Services. The wage rates, wage increase assumptions, severance costs, and step increase assumptions are provided by Administrative Services. Benefits and payroll taxes (including pension, long-term disability, workers compensation, health and life insurance, and other costs) are determined by the Administrative Services staff. The development of severance costs, benefit and payroll tax amounts is described in greater detail in the Direct Testimony of Mr. James V. Haner. Overtime factor estimates are provided by Big Rivers' department managers for their staff. The pertinent pieces of information are input into Hyperion by budget department staff to calculate the labor budget.

Q. How is the capital budget developed?

A. The capital budget development is facilitated by budget department staff in conjunction with a team of individuals from Production, System Operations, Information Services, and other departments (the "Capital Team"). Each area identifies capital requirements for its area based on needs, replacement frequency, and outage schedules. The proposed capital projects are compiled and analyzed by the budget department staff. The budget department facilitates a meeting with the Capital Team to discuss and scrutinize the projects that are proposed in the capital budget. The final output from this meeting becomes the proposed capital budget.

Q. How is the budget for production-related non-fuel variable costs developed?

A. The production-related non-fuel variable costs in the budget are based on the results of production cost modeling performed by ACES, which are incorporated into the Big Rivers financial model. Certain assumptions and data are provided by Big Rivers to ACES for inclusion in the production cost modeling, as noted in the Direct Testimony of Mr. Robert W. Berry. The production cost model output data – including generation volumes, costs, allowances, etc. -- are then provided from ACES to Big Rivers for inclusion in the Big Rivers financial model; this is described in further detail in the Direct Testimony of Mr. Travis A. Siewert.

Q. How is the fuel budget developed?

A. The Big Rivers' Fuel department provides a summary of all of Big Rivers' long-term fuel procurement contracts (including volumes and prices) to ACES as an input to the production cost modeling. ACES then uses this data and its own fuel price projections in the production cost model, as described in the Direct Testimony of Mr. Robert W. Berry.

Q. How is the emission fee budget developed?

A. The emission fee budget is developed by Big Rivers' environmental department staff based on outputs from the production cost modeling related to emissions. An estimated price per ton is established based on historical prices. The costs are then provided to the budget department to incorporate into the overall budget.

Q. How is the load forecast developed?

A. This is described in the Direct Testimony of Ms. Lindsay N. Barron. The load forecast is not a direct budget item, but is included as an input to the production cost model and is also included in the determination of member revenues.

Q. How is the off-system sales forecast developed?

A. The volume and price of off-system sales are related to the production cost model, as described in the Direct Testimony of Mr. Robert W. Berry. Both volume and price are data inputs to the Big Rivers financial model, in which the overall effect of off-system sales on Big Rivers' financials is calculated. This is described in the Direct Testimony of Mr. Travis A. Siewert.

Q. How are the budget estimates for MISO transmission expense, MISO transmission revenue, TVA transmission fees, and TVA transmission revenue developed?

A. The costs and associated revenues for these items are established by Energy Services staff and provided to the budget department staff to incorporate into the overall budget. These items are described in further detail in the Direct Testimony of Mr. Robert W. Berry.

Q. How is the budget for ACES costs and MISO administrative fees developed?

A. These costs are established by Energy Services staff and provided to the budget department to incorporate into the overall budget. These are described in the Direct Testimony of Mr. Robert W. Berry.

Q. Does the budget include any additional non-member revenues?

A. Yes, the budget includes rental income, interest income, and patronage allocations. These are described in greater detail in the Direct Testimony of Mr. Travis A. Siewert.

Q. How are costs for HMP&L's general and administrative costs allocated to Big Rivers developed?

A. HMP&L staff provides Big Rivers' budget department staff with an estimate of their general and administrative costs allocated to Big Rivers for HMP&L's current fiscal year. The cost sharing agreement is described in Section 4.2 of the Station Two G&A Allocation Agreement, a copy of which Big Rivers filed on May 5, 2009, in Case No. 2007-00455. These costs are incorporated into the overall budget by budget department staff.

Q. How is the budget for interest on long-term debt and amortization of debt expense developed?

A. Interest on long-term debt and amortization of debt expense are calculated by finance department staff and incorporated into the overall budget.

These are described in greater detail in the Direct Testimony of Mr. Travis A. Siewert.

Q. How is the budget for Big Rivers' share of Station Two costs developed?

A. For the variable costs related to the dispatch and operation of HMP&L's Station Two generating station, Big Rivers calculates its share in the Big Rivers financial model, so that the results of the production cost model that are included in the Big Rivers financial model are net of HMP&L's share of Station Two. In other words, the Big Rivers financial model includes only Big Rivers' share and excludes HMP&L's share of Station Two variable costs. This is described in greater detail in the Direct Testimony of Mr. Travis A. Siewert. The other costs shared between Big Rivers and HMP&L that are not reflected in the production cost model (e.g., labor and fixed departmental expenses) are accounted for in the budgeting process, pursuant to the contractual agreement between Big Rivers and the City of Henderson.

Q. How is the budget for depreciation and amortization, property taxes, and property insurance developed?

A. Depreciation, amortization and property taxes are provided by the Finance department. Property insurance is provided by the Administrative Services department. This information is incorporated into the Big Rivers financial model.

Q. How is the revenue budget developed?

A. Big Rivers calculates the revenues from sales to members in the Big Rivers financial model. This is described in greater detail in the Direct Testimony of Mr. Travis A. Siewert.

Q. How is amortization of certain deferred expenditures captured in the budget?

A. The budget includes amortization for environmental compliance plan ("ECP") costs incurred as approved in the Commission Order dated October 1, 2012, in Case No. 2012-00063; amortization of severance costs; and amortization of rate case expenses. Amortization schedules for these costs are contained in Big Rivers' financial model. Amortization of the ECP costs in the amount of approximately $769,000 began in late 2012 and continues through September 2015 in the budget (36 months). Amortization of severance costs of $4.6 million is budgeted to begin September 2013 for 60 months. The development of severance costs is described in greater detail in the Direct Testimony of Mr. James V. Haner. Amortization of general rate case expenses of approximately $1.6 million is budgeted to begin September 2013 for 36 months. This amount includes estimated expenses for: (i) direct legal expenses associated with this rate case, (ii) the completion of a cost of service study required as part of the rate case, (iii) the completion of a depreciation study also required as part of the rate case, and (iv) additional expert witnesses and/or consultants needed during the course of the rate case. This estimate was developed by members of both the Finance department and the Governmental Relations and Enterprise Risk Management department based on a variety of factors including, but not limited to:

1. Big Rivers' experience in previous rate case proceedings
2. Analysis of the various filing requirements and anticipated work loads
3. Additional complexities associated with a rate case using a fully forecasted test period
4. Hourly rate information provided by external service providers

Q. How are Line of Credit ("LOC") fees and amortization of upfront LOC fees derived?

A. Budgeted expenses for line of credit fees and amortization of upfront costs associated with lines of credit are provided by the Finance department. Estimated expenses for line of credit fees are based on the terms of Big Rivers' revolving credit facilities and existing commitments under those lines of credit. Budgeted amortization of up-front fees for lines of credit is based on amortization schedules for the deferred expenses associated with the individual revolving lines of credit.

Q. How is the budget for FDE derived?

A. FDE comprises departmental expenses not discussed above (*e.g.*, plant and transmission operational and maintenance activities, outside services, professional services, fees, dues and various other items). The amounts are developed by the managers of various departments across Big Rivers in conjunction with the budget department staff. These individuals consider anticipated activities such as rate case filings, technical studies, other regulatory filing matters, or other initiatives for which outside professional services are required. Fees, dues, and other membership costs are determined within each department and budgeted based on quotes, research or historical information, or a combination thereof, for a particular expenditure. Plant operation and maintenance activities not related to production cost model expenses, transmission operation and maintenance activities, and general and administrative type expenses are developed by various departments. Each department determines its requirements for the budget period and includes the costs based on quotes, research, or historical information, or a combination thereof, for a particular expenditure. These costs are then incorporated into the overall budget, excluding HMP&L's share of Station Two, via Hyperion.

Q. How does Big Rivers incorporate the proposed rates into its budget?

A. The proposed demand and energy rates, as described in the Direct Testimony of Mr. John Wolfram, are inputs to the Big Rivers financial model. The financial model then produces expected revenues that stem from the application of the proposed rates to the demand kW and the energy kWh for the Big Rivers rate classes. These revenues are part of the Big Rivers budget for the fully forecasted test period and beyond.

Q. How did the Big Rivers budget process change on or after August 20, 2012, after the Century Aluminum of Kentucky General Partnership ("Century") issued its 12 month notice to terminate its power contract?

A. The notice of termination of the Century contract required Big Rivers to revisit certain elements of its budget process that were already well underway, *e.g.*, the development of the production cost model, by the time the notice was received. After August 20, 2012, Big Rivers revised the original budget process outlined in Exhibit Speed-2 to allow Big Rivers to incorporate the change into its budget without measurably altering the timeframe for completing the budget process. The revised budget process is outlined in Exhibit Speed-3.

IV. BUDGETS FOR 2013 AND 2014

Q. Were the budgets for 2013 and 2014, which are the basis for the fully forecasted test period in this filing, approved by the Big Rivers Board of Directors?

A. Yes. The 2013 budget and the 2014-2016 financial plans were approved by the Big Rivers Board of Directors on November 16, 2012.

Q. Does the revenue in the budget include the rate increase proposed in this filing?

A. Yes. The budget reflects a revenue increase stemming from the proposed rate change beginning on August 21, 2013.

Q. Does the budget include the anticipated costs for professional services associated with this proceeding?

A. Yes. The budget has the rate case expenses for this case built in on a three-year amortization. For this reason, a *pro forma* adjustment to test period expenses to account for rate case expenses is not needed. The total estimated amount of these costs is $1,585,980, or $44,055 per month when amortized over thirty-six months, beginning in September 2013.

Q. Does the budget include the effects of the proposed depreciation rates described in the Direct Testimony of Mr. Ted J. Kelly?

A. Yes. The new depreciation rates were used to determine the depreciation expenses in the budget. For this reason, a *pro forma* adjustment to test period expenses to account for revised depreciation rates is not needed.

Q. Is any other item built into the budget that might have otherwise required a *pro forma* adjustment had an historical test period been used?

A. Yes. Big Rivers has included severance expenses in the fully forecasted test period, for the reasons described in the Direct Testimony of Mr. Robert W. Berry. In the budget, a regulatory account is set up for these costs in

August 2013, and the costs are amortized over sixty months beginning in September 2013. Because the amortization begins in the first month of the fully forecasted test period, this item is already included and does not require a *pro forma* adjustment to test period expenses. The total cost is $4.6 million. The derivation of the amount is discussed in detail in the Direct Testimony of Mr. James V. Haner.

V. FILING REQUIREMENTS

Q. Are you sponsoring any of the answers provided in Tabs 1-62 which address Big Rivers' compliance with the fully forecasted test period filing requirements under 807 KAR 5:001 and its various subsections?

A. Yes. I hereby incorporate and adopt those portions of Tabs 1-62 for which I am identified as the sponsoring witness

VI. CONCLUSION

Q. What are your conclusions and recommendations to the Commission in this proceeding?

A. Big Rivers employs a detailed and rigorous process for the development of its annual budgets. The fully forecasted test period relies on annual budgets that are reasonable, reliable, made in good faith, and relies upon assumptions that are justified. The fully forecasted test period in this rate filing relies on the same budgeting process, assumptions, and results that are used by Big Rivers' management in the ordinary course of business. The budget reflects that for 2013 and beyond, Big Rivers requires the proposed rate increase in order to meet the obligations described in the Direct Testimony of Ms. Billie J. Richert. The Commission should approve the proposed rates as filed by Big Rivers in this proceeding.

Q. Does this conclude your testimony?

A. Yes.

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES CASE NO. 2012-00535

VERIFICATION

I, DeAnna M. Speed, verify, state, and affirm that I prepared or supervised the preparation of my testimony filed with this Verification, and that testimony is true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

DeAnna M. Speed

DeAnna M. Speed

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by DeAnna M. Speed on this the 9th day of January, 2013.

Paula Mitchell

Notary Public, Ky. State at Large
My Commission Expires 1-12-17

Professional Summary

DeAnna M. Speed, CPA
Manager-Budgets
Big Rivers Electric Corporation
201 3rd Street
Henderson, Kentucky 42420
(270) 844-6042

Professional Experience

Big Rivers Electric Corporation 2009-Present, 1994-1998

Manager-Budgets

Accountant, Budgets

Western Kentucky Energy 1998-2009

Manager of Budgeting

Budget Analyst (I, II, III and Sr.)

Education

Master of Business Administration Candidate

Murray State University, Murray, KY, expected graduation 2014

Bachelor of Science in Accounting

Western Kentucky University, Bowling Green, KY, 1992

Certifications

Certified Public Accountant – CPA

Professional Organizations

Kentucky Society of Certified Public Accountants

Institute of Management Accountants

Big Rivers Electric Corporation
2013 Budget and 2014-2016 Financial Plan
Original Calendar

#	Timing	Task Description
1	Apr	Distribute Budget Calendar
2	May	Production Cost Model (PCM) Kickoff Meeting
3	May	HR Issues Wage Increase Assumptions and Headcount Information with Wage Rates to Budget Manager
4	May	Generation Model Inputs & Outage Schedule Completed for the PCM
5	May	Individual Headcount Files Distributed to Appropriate Managers+
6	May	Headcount, Overtime Rate Assumptions, Capitalizable Labor Estimates, and Step Increase Assumptions Finalized and Returned to Budget Department Staff by Appropriate Managers
7	May	PCM Available for Internal Review
8	Jun	PCM Completed and Provided to Budget Department Staff
9	Jun	First Draft of Capital Budget File Completed
10	Jun	Complete Labor Inputs in Hyperion (first draft)
11	Jun	Final Draft of Raw Straight-time & Raw OT Labor Sent to HR/Payroll for Benefits, Payroll Taxes, and PTO (Burden) Calculation
12	Jun	CAPEX Review Meeting (First Pass of Capital Budget and Financial Plan)
13	Jun	Sales and Load Forecast Billing Units Completed for Budget and Financial Plan (Using PCM Output)
14	Jun	Production Fixed Departmental Expense (FDE) - First Pass Due
15	Jun	Production FDE Review Meeting (First Pass) with VP Production
16	Jun	Headcount "Churn" Established by VP Administrative Services
17	Jun	Straight Time Hours Worked Assumption Finalized by Payroll (2080 hrs less PTO hrs used in burden calc)
18	Jun	Payroll Burden Dollars Finalized and Provided to Manager Budgets
19	Jun	Assumption for BREC Share of HMPL G&A Costs Completed
20	Jun	Educational Assistance Forms Due to Human Resources
21	Jun	Capital Plan Finalized
22	Jun	Labor Budget and Financial Plan Completed
23	Jun	Depreciation & Amortization Calculations Start
24	Jun	Capitalzed Interest Calculation Starts
25	Jul	Labor Analysis Completed

Big Rivers Electric Corporation
2013 Budget and 2014-2016 Financial Plan
Original Calendar

#	Timing	Task Description
26	Jul	Fuel Budget based on PCM Outputs Completed
27	Jul	All FDE Budgets Finalized and Submitted
28	Jul	ACES Power Marketing Costs Submitted
29	Jul	PJM Annual Fee Submitted
30	Jul	Reagent Budgets based on PCM Outputs Completed
31	Jul	Landfill Capping Budget Completed
32	Jul	Property Tax Expense and Cash Flow, AMT/Income Tax Submitted
33	Jul	Property Insurance Expense and Cash Flow Submitted
34	Jul	TVA Reservation Fees and Related Revenue Submitted
35	Jul	Investment Income Completed
36	Jul	Misc Transmission Revenue from HMPL (usually $1500/mo) Finalized
37	Jul	SIPC Agreement Estimates Submitted
38	Jul	Other Revenue Submitted - Pasture Rent, Crop/Oil Income
39	Jul	Member Revenue, Smelter Revenue, OSS Revenue, Amortization of Economic Reserve Completed
40	Jul	Purchased Power Budget based on PCM Outputs Completed
41	Jul	Emissions Fees Budget Submitted
42	Jul	Interest Expense Finalized
43	Jul	Depreciation & Amortization and Capitalized Interest Submitted
44	Jul	Rent Amortization Submitted - Hanson Site Lease
45	Jul	MISO Administrative Fee Estimates Submitted
46	Jul	Amortization of Deferred Expenses (e.g. ECP Expenses) Completed
47	Jul	Letter Of Credit Fees and Amort of LOC Fees Submitted
48	Jul	MISO Transmission Expense and Related Revenue Submitted
49	Jul	Amortization of Debt Expense Completed
50	Jul	Allowance Expense Completed

Big Rivers Electric Corporation
2013 Budget and 2014-2016 Financial Plan
Original Calendar

#	Timing	Task Description
51	Jul	Patronage Assumptions Finalized
52	Jul	All Other Costs for the Budget & Financial Plan Finalized
53	Aug	Financial Model Update Finalized for the Draft (Stmt of Operations)
54	Aug	Sr. Mgt &/or IRMC Review
55	Sep	Communicate Budget Draft results with the Board
56	Oct	Send Draft of the Budget (forecast) to Smelters (Contractual Deadline)
57	Dec	Presentation to the Board of Directors
58	Dec	Send Approved Budget to Smelters (Contractual Deadline)
59	Feb 2013	Send Approved 3-year Budgeted Financials to CoBank (Contractual Deadline)

Big Rivers Electric Corporation
2013 Budget and 2014-2016 Financial Plan
Revised Calendar

#	Timing	Task Description
1	Late Aug	Outage Schedule Completed
2	Late Aug	Generation Model Inputs Re-evaluated
3	Late Aug	Smelter Load Assumptions Finalized
4	Late Aug	Plant Assumptions for PCM Finalized
5	Late Aug	Production Cost Model (PCM) Inputs Ready for Distribution
6	Sep	CAPEX Budget Revised
7	Sep	Depreciation & Amortization and Capitalized Interest Calculations for the Revised CAPEX Start
8	Sep	Labor Revisions (OT and Headcount) Due
9	Sep	Final Draft of Raw ST and OT Labor sent to HR/Payroll for Burden Dollar Re-Calculation
10	Sep	Revise Property Tax Expense and Cash Flow
11	Sep	MISO Administrative Fee Revised
12	Sep	PCM Completed and Provided to Budget Department Staff
13	Sep	Payroll Burden Dollars Finalized
14	Sep	Depreciation & Amortization and Capitalized Interest Revision Due
15	Sep	Labor Budget and Financial Plan Completed
16	Sep	All FDE Revisions Completed
17	Sep	Labor Analysis Completed
18	Sep	Fuel, Reagent and Purchased Power Budgets based on Revised PCM Outputs Completed
19	Sep	Review Other Expenses/Revenues to Determine If Revisions are Required
20	Sep	Investment Income Completed
21	Sep	Member Revenue, Smelter Revenue, OSS Revenue, Amortization of Economic Reserve Completed
22	Sep	Interest Expense Revised
23	Sep	Financial Model Update Finalized for the Draft (Stmt of Operations)
24	Sep	Sr. Mgt &/or IRMC Review
25	Sep	Communicate Budget Draft results with the Board
26	Oct	Send Draft of the Budget (forecast) to Smelters (Contractual Deadline)
27	Nov	Presentation to the Board of Directors
28	Dec	Send Approved Budget to Smelters (Contractual Deadline)
29	Feb 2013	Send Approved 3-year Budgeted Financials to CoBank (Contractual Deadline)

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

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

DIRECT TESTIMONY

OF

LINDSAY N. BARRON
MANAGING DIRECTOR, ENERGY SERVICES

ON BEHALF OF

BIG RIVERS ELECTRIC CORPORATION

FILED: January 15, 2013

DIRECT TESTIMONY
OF
LINDSAY N. BARRON

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DIRECT TESTIMONY
OF
LINDSAY N. BARRON

I. INTRODUCTION

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

A. My name is Lindsay N. Barron. I am employed by Big Rivers Electric Corporation ("Big Rivers"), 201 Third Street, Henderson, Kentucky 42420, as Managing Director, Energy Services.

Q. Please describe your job responsibilities.

A. As Managing Director, Energy Services, I am responsible for the strategic management and oversight of all activities associated with the Energy Services department. I oversee a staff of four individuals who work to provide value to Big Rivers through power portfolio optimization, Midwest Independent Transmission System Operator, Inc. ("MISO") market participation, load forecasting, resource planning, and member economic development support.

Q. Briefly describe your education and work experience.

A. I first joined Big Rivers in October 1998 in the Accounting Department. I held various roles in Accounting/Purchasing before transitioning to Power Supply in March of 2003 as Economic Analyst/Market Coordinator. I joined Vectren Corporation as an Energy Market Analyst in 2005 and served as

Manager, Market Research & Analysis for Vectren from December 2006 to August 2010. I returned to Big Rivers as Director of Risk Management & Strategic Planning in September 2010, and assumed my current role in June 2012. I am a Certified Public Accountant and earned a Master of Business Administration degree and a Bachelor of Science in Accounting from the University of Southern Indiana. A summary of my education and work experience is attached as Exhibit Barron-1.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain the methodology and assumptions used in the development of Big Rivers' demand and energy forecast.

Q. Are you sponsoring any exhibits?

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

1. Exhibit Barron-1 Qualifications of Lindsay N. Barron;
2. Exhibit Barron-2 U.S. Department of Agriculture, Rural Utilities Service Approval Letter for 2011 Load Forecast; and
3. Exhibit Barron-3 2013 and 2014 Energy and Demand Forecast.

III. LOAD FORECAST PROCESS

Q. What is the load forecast?

A. The load forecast is a projection of future energy and peak demand that reflects both changes in usage per customer and customer growth. The forecast is based on economic trends, demographic trends, consumer end-usage and weather data. The forecast is an input to the production cost model and to the Big Rivers financial model and thus drives the calculation of operational expenses and projected revenues. It is also an input to the cost of service study.

Q. How often does Big Rivers produce a load forecast?

A. Big Rivers is required by the U.S. Department of Agriculture, Rural Utilities Services ("RUS") to update its load forecast every two years and to submit the forecast to RUS for review and approval. Accordingly, Big Rivers ordinarily retains an outside consultant to produce a formal load forecast study every two years. In between, and/or as needed, Big Rivers' staff updates the load forecast to reflect changes in direct serve loads, transmission loss rates or other material information.

Q. Has Big Rivers submitted the current load forecast to RUS for review and approval?

A. Yes. The current forecast (the "2011 Load Forecast") was submitted to RUS on November 9, 2011, and was approved by RUS on July 16, 2012. A copy of the RUS approval letter is attached as Exhibit Barron-2. As noted in the letter, RUS states that "the methods and assumptions used are reasonable."

Q. To what extent were you involved in the modeling that Big Rivers performed in developing its load forecast?

A. Personnel under my direction worked with GDS Associates, Inc., ("GDS") in the preparation of the 2011 Load Forecast that was subsequently updated by Big Rivers' staff (as previously described) and used in the development of Big Rivers' budgets and the development of this application.

Q. How are the load forecast values used in the calculation of rates and other elements of this filing?

A. The load forecast is the basis for calculating projected revenue for the 2013 and 2014 budget years. The load forecast is also used to develop the test year billing determinants used in this proceeding.

Q. How was Big Rivers' load forecast developed?

A. The Big Rivers load forecast was developed using methods recognized in the industry today as the standards, including econometrics, end-use, informed judgment, and historical trends. The forecast is developed using a "bottom-up" approach, as forecasts are developed individually for each of Big Rivers' three member distribution cooperatives and aggregated to the Big Rivers level. For each distribution cooperative forecast, econometric models were developed to project the number of residential customers, number of small commercial customers, and small commercial energy use per customer. Total small commercial sales represent the product of number of customers and energy use per customer. Statistically Adjusted End-Use (*i.e.*, SAE) models were developed to project residential energy consumption per customer. Total residential sales represent the product of number of customers and energy consumption per customer. The number of customers and corresponding energy sales for the large commercial classification are developed individually for each customer and based on historical trends and information obtained by distribution cooperative management from the customers. The models incorporate a combination of electric system, economic, weather, price, end-use and housing characteristics data.

Q. How is the smelter load (i.e., the load from Alcan Primary Products Corporation ("Alcan") and Century Aluminum of Kentucky General Partnership ("Century")) included in the demand and energy forecast?

A. The smelter load is built into the forecast consistent with the terms and conditions of the smelter agreements. The smelter demand is forecasted as the contract demand amount and the smelter energy is forecasted as the contract demand at 98% load factor.

Q. How was the load forecast revised to reflect the Century contract termination described by other Big Rivers witnesses?

A. As a result of the Century contract termination, beginning on August 20, 2013, Big Rivers reduced its peak demand forecast by 482 MW and its energy forecast by 4,138 GWh/year. The demand reduction represents Century's full contract demand specified in the smelter agreement, and the energy reduction represents the full contract demand at 98% load factor, consistent with the terms and conditions for billing as specified in the smelter agreement. These reductions result in the elimination of one hundred percent of the Century load from the Big Rivers load forecast.

Q. What is the role of the Big Rivers' members in the load forecast process?

A. Big Rivers' load forecasting process is a collaborative effort between Big Rivers and its members. Member input is an integral part of the load forecast development process, as Big Rivers' load forecast is built by aggregating its members' forecasts. Big Rivers' members provide feedback during the development of the load forecast and provide a review of the results prior to finalization.

Q. Is the budgeting load forecast consistent with the forecast employed in the Integrated Resource Planning ("IRP") process?

A. Yes. The same basic load forecast is used for budgeting, the IRP and other day-to-day functions at Big Rivers, so there is no difference in the process.

IV. LOAD FORECAST RESULTS

Q. What are the results of the forecast?

A. The results of the load forecast are provided in Exhibit Barron-3. The forecast values for demand and energy are provided by month for 2013 and 2014. The demand and energy forecasts are provided for the Rural rate class and for each of the Large Industrial customers that are direct-served by Big Rivers pursuant to the LIC Rate Schedule. Smelter demand and energy are also provided.

Q How do the forecast results compare to the actual historic load that Big Rivers experienced in 2011 or 2012?

A. With the obvious exception of the forecast for Century load, the values in the forecast for 2013 and 2014 are not significantly different than those actually experienced in 2011 or 2012. 2011 actual member Rural and Large Industrial sales (excluding Alcan and Century) totaled 3,344,199 MWhs, while the 2013 and 2014 projected sales are 3,352,857 and 3,392,495 MWhs, respectively.

Q Are the load forecast results used in this rate filing different in any way from the load forecast data used by Big Rivers in its day-to-day management of the business?

A. No. The demand and energy forecast values used in this rate filing are the same values that are used by Big Rivers' management in the ordinary course of business.

V. <u>FILING REQUIREMENTS FROM 807 KAR 5:001</u>

Q. Have you reviewed the answers provided in Tabs 1-62, which address Big Rivers' compliance with forecasted period filing requirements under 807 KAR 5:001 and its various subsections?

A. Yes. I have, and I hereby incorporate and adopt those portions of Tabs 1-62 for which I am identified as the sponsoring witness.

VI. CONCLUSION

Q. What are your conclusions and recommendations to the Commission in this proceeding?

A. Big Rivers employs a detailed and rigorous process for the development of its load forecast. The fully-forecasted test period relies on a load forecast that is reasonable, reliable, made in good faith, and based on assumptions that are justified. The fully-forecasted test period in this rate filing relies on the same load forecasting process, assumptions, and results that are used in the IRP process and that are used by Big Rivers' management in the ordinary course of business. The underlying forecast used in this filing was approved by RUS on July 16, 2012, and was found by RUS to be reasonable. The load forecast is appropriately adjusted to reflect the Century contract termination that will become effective just prior to the beginning of the twelve-month forecasted test period. The Commission should accept the load forecast as presented and as utilized in the modeling of Big Rivers' financials for the fully-forecasted test period.

Q. Does this conclude your testimony?

A. Yes.

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES CASE NO. 2012-00535

VERIFICATION

I, Lindsay N. Barron, verify, state, and affirm that I prepared or supervised the preparation of my testimony filed with this Verification, and that testimony is true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Lindsay N. Barron

Lindsay N. Barron

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Lindsay N. Barron on this the 8th day of January, 2013.

Notary Public, Ky. State at Large
My Commission Expires 8-9-14

Professional Summary

Lindsay N. Barron, CPA
Managing Director Energy Services
Big Rivers Electric Corporation
201 3rd Street
Henderson, Kentucky 42420
(270) 844-6194

Professional Experience

Big Rivers Electric Corporation, Henderson, KY — 2010 to present, 1998 to 2005

- Managing Director Energy Services
- Director Risk Management and Strategic Planning
- Market Coordinator/Economic Analyst
- Cash Management and Fixed Asset Accountant
- Accounting Clerk/Purchasing Buyer

Vectren Corporation, Evansville, IN — 2005 to 2010

- Manager Market Research and Analysis
- MISO Settlements Supervisor
- Market Analyst

Education

Master Certificate in Human Resource Management
  Villanova University, Villanova, Pennsylvania, 2012

Master of Business Administration
  University of Southern Indiana, Evansville, Indiana, 2003

Bachelor of Science in Accounting
  University of Southern Indiana, Evansville, Indiana, 2001

Associate of Science in Management Information Systems
  Henderson Community College, Henderson, KY, 1998

Certifications

Certified Public Accountant – CPA
Certified Management Accountant – CMA
Certified in Financial Management – CFM
Certified Business Resilience Manager – CBRM

Professional Organizations

Kentucky Society of Certified Public Accountants
Institute of Management Accountants
American Institute of Certified Public Accountants

USDA Rural Development

United States Department of Agriculture
Rural Development

Original-Berry
cc - Hite
Crockett
Cofley

JUL 16 2012

JUL 20 2012

Mr. William Denton
President and CEO
Big Rivers Electric Corporation, Inc.
P. O. Box 24
Henderson, Kentucky 42419-0024

Dear Mr. Denton:

We have reviewed the 2011 Load Forecast (Forecast) for Big Rivers Electric Corporation, Inc. (Big Rivers) and its members. The studies and board resolutions were submitted to the Rural Utilities Service (RUS) on November 9, 2011, and prepared pursuant to the 2011 Work Plan approved by the agency on June 19, 2012. The methods and assumptions used are reasonable. The Forecast was effectively coordinated with all of Big Rivers' members. A certified resolution dated September 16, 2011, from Big Rivers' Board of Directors approving the Forecast and its uses, was submitted to RUS.

This letter documents RUS approval of Big Rivers' 2011 Forecast. Member studies developed in coordination with this Forecast are also approved. The agency will consider the 2011 studies current, pursuant to 7 CFR 1710 Subpart E, Load Forecasts. Big Rivers and its members must use these Forecasts in all engineering, environmental, financial studies, financial forecasts, and in any studies in support of loan applications.

A copy of this letter is being sent to each of Big Rivers' members.

Sincerely,

Georg A Shultz

GEORG A. SHULTZ
Director
Electric Staff Division
Rural Utilities Service

cc:
Mr. David Wilson
President and CEO
Meade County Rural Electric Cooperative Corp.
P.O. Box 489
Brandenburg, Kentucky 40108-0489

Mr. G. Kelly Nuckols
Manager
Jackson Purchase Energy Corp.
P.O. Box 4030
Paducah, Kentucky 42002-4030

Mr. John Warren
President and CEO
Kenergy Corporation
P.O. Box 18
Henderson, Kentucky 42419-0018

Mr. John Hutts
GDS Associates, Inc.
Suite 800
1850 Parkway Place SE
Marietta, Georgia 30067

Big Rivers ELECTRIC CORPORATION

DEMAND AND ENERGY BUDGET
2013 - 2014

BILLING DEMAND (MW) - 2013

	January 2013	February 2013	March 2013	April 2013	May 2013	June 2013
KENERGY	264.1	237.7	208.7	166.4	192.7	241.5
JACKSON PURCHASE	146.7	130.5	114.4	88.0	110.3	140.7
MEADE COUNTY	129.4	113.9	95.7	73.8	71.6	90.0
TOTAL MEMBER RURAL DEMAND	540.2	482.1	418.8	328.2	374.5	472.2
ACCURIDE	5.2	5.3	5.4	5.4	5.5	5.4
ALCOA	0.1	0.2	0.2	0.2	0.2	0.2
ALERIS	28.2	27.4	27.2	26.6	26.7	26.6
ALLIED (STEMPORT)	7.0	7.2	6.9	6.9	6.4	6.9
ARMSTRONG DOCK	5.4	5.2	4.7	4.3	4.2	4.1
ARMSTRONG EQUALITY	3.0	2.7	3.1	3.3	3.0	3.1
ARMSTRONG LEWIS CREEK	1.9	3.2	3.2	3.2	3.2	3.2
ARMSTRONG MIDWAY	3.7	3.7	3.8	3.5	3.3	3.5
ARVIN ROLL COATER	3.8	3.8	3.8	3.8	3.8	3.8
DOMTAR	15.0	15.0	15.0	15.0	15.0	15.0
DOTIKI	0.8	0.8	0.8	0.8	0.8	0.8
HOPKINS CO. COAL	0.3	0.5	0.4	0.4	0.4	0.4
KBI ALLOY	2.0	2.0	2.0	2.0	2.0	2.0
KIMBERLY CLARK	36.2	36.2	36.5	36.8	36.6	36.8
KMMC, Inc./P&M/Cochise	0.3	0.2	0.2	0.2	0.1	0.1
PATRIOT COAL	5.2	5.3	4.9	5.0	4.7	4.6
Shell Oil JP Industrials	3.4	3.4	3.4	3.4	3.4	3.4
SOUTHWIRE COMPANY	6.7	6.9	6.6	6.9	6.7	6.9
TYSON	9.1	9.0	9.1	10.0	10.5	10.0
VALLEY	2.0	2.0	2.0	1.8	2.0	1.9
TOTAL MEMBER NCP IND'L DEMAND	139.3	139.9	139.1	139.4	138.4	138.5
ALCAN	368.0	368.0	368.0	368.0	368.0	368.0
CENTURY	482.0	482.0	482.0	482.0	482.0	482.0
TOTAL	1,529.5	1,472.0	1,407.9	1,317.6	1,363.0	1,460.7

Case No. 2013-00535
Exhibit Barron-3

Big Rivers
ELECTRIC CORPORATION

DEMAND AND ENERGY BUDGET
2013 - 2014

BILLING DEMAND (MW) - 2013

	July 2013	August 2013	September 2013	October 2013	November 2013	December 2013	TOTAL
KENERGY	252.4	271.4	219.8	171.0	192.8	243.0	2,661.4
JACKSON PURCHASE	147.1	159.8	116.7	95.9	104.1	134.9	1,489.1
MEADE COUNTY	94.1	102.3	79.8	69.5	80.2	116.5	1,116.7
TOTAL MEMBER RURAL DEMAND	493.5	533.5	416.3	336.4	377.2	494.4	5,267.2
ACCURIDE	5.5	5.4	5.5	5.5	5.4	5.5	65.0
ALCOA	0.2	0.2	0.2	0.2	0.2	0.2	2.1
ALERIS	26.7	26.6	26.7	26.7	26.6	26.7	322.5
ALLIED (STEMPORT)	6.4	6.9	6.4	6.4	6.9	6.4	80.6
ARMSTRONG DOCK	4.2	3.7	2.1	4.0	4.4	4.8	51.2
ARMSTRONG EQUALITY	3.2	3.1	3.2	3.2	3.2	3.2	37.2
ARMSTRONG LEWIS CREEK	3.2	3.2	3.2	3.2	3.2	3.2	37.1
ARMSTRONG MIDWAY	3.3	3.5	3.3	3.3	3.5	3.3	41.6
ARVIN ROLL COATER	3.8	3.8	3.8	3.8	3.8	3.8	45.0
DOMTAR	20.0	20.0	15.0	15.0	15.0	15.0	190.0
DOTIKI	0.8	0.8	0.8	0.8	0.8	0.8	9.6
HOPKINS CO. COAL	0.4	0.4	0.4	0.4	0.4	0.4	4.6
KBI ALLOY	2.0	2.0	2.0	2.0	2.0	2.0	24.0
KIMBERLY CLARK	36.6	36.8	36.6	36.6	36.8	36.6	439.3
KMMC, Inc./P&M/Cochise	0.1	0.1	0.1	0.1	0.1	0.1	1.6
PATRIOT COAL	4.5	5.0	5.0	4.5	4.5	4.5	57.7
Shell Oil JP Industrials	3.4	3.4	3.4	3.4	3.4	3.4	40.8
SOUTHWIRE COMPANY	6.7	6.9	6.4	7.1	6.7	6.5	81.0
TYSON	10.5	10.0	10.5	10.5	10.0	10.5	119.6
VALLEY	1.9	1.9	1.9	1.9	1.8	1.8	22.7
TOTAL MEMBER NCP IND'L DEMAND	143.2	143.5	136.4	138.5	138.4	138.6	1,673.3
ALCAN	368.0	368.0	368.0	368.0	368.0	368.0	4,416.0
CENTURY	482.0	482.0	-	-	-	-	3,856.0
TOTAL	1,486.7	1,527.0	920.7	842.9	883.6	1,001.0	15,212.5

Big Rivers ELECTRIC CORPORATION

DEMAND AND ENERGY BUDGET
2013 - 2014

ENERGY (MWh) - 2013

	January 2013	February 2013	March 2013	April 2013	May 2013	June 2013
KENERGY	125,747	105,458	95,990	75,974	84,968	112,429
JACKSON PURCHASE	67,676	55,365	51,467	41,604	48,133	62,855
MEADE COUNTY	55,784	47,206	40,202	30,299	32,088	41,475
TOTAL MEMBER RURAL ENERGY	249,207	208,029	187,659	147,877	165,188	216,760
ACCURIDE	1,744	1,602	1,823	1,784	1,894	1,784
ALCOA	86	78	99	121	83	121
ALERIS	14,931	14,375	15,269	14,999	15,600	14,999
ALLIED (STEMPORT)	2,797	2,711	3,015	2,519	2,384	2,519
ARMSTRONG DOCK	2,045	2,012	1,703	1,140	1,194	1,340
ARMSTRONG EQUALITY	997	1,038	1,267	1,299	1,198	1,234
ARMSTRONG LEWIS CREEK	981	1,492	1,652	1,599	1,652	1,599
ARMSTRONG MIDWAY	2,050	1,993	2,002	1,572	1,551	1,572
ARVIN ROLL COATER	1,739	1,570	1,739	1,739	1,739	1,739
DOMTAR	10,993	9,929	10,993	10,638	10,993	10,638
DOTIKI	544	493	573	542	543	544
HOPKINS CO. COAL	190	74	187	138	170	167
KBI ALLOY	655	548	651	629	535	629
KIMBERLY CLARK	25,301	23,565	25,831	24,983	25,599	24,983
KMMC, Inc./P&M/Cochise	92	83	60	48	40	37
PATRIOT COAL	2,173	2,386	2,293	2,244	2,005	1,648
Shell Oil JP Industrials	1,250	1,250	1,250	1,250	1,250	1,250
SOUTHWIRE COMPANY	4,174	3,681	4,159	3,950	4,299	4,073
TYSON	5,026	4,578	5,022	5,220	5,528	5,220
VALLEY	746	847	809	809	760	769
TOTAL MEMBER IND'L ENERGY	78,513	74,303	80,396	77,223	79,017	76,864
ALCAN	275,607	248,936	275,607	266,717	275,607	266,717
CENTURY	351,436	317,426	351,436	340,099	351,436	340,099
TOTAL	954,763	848,694	895,098	831,916	871,249	900,440

Big Rivers ELECTRIC CORPORATION

DEMAND AND ENERGY BUDGET
2013 - 2014

ENERGY (MWh) - 2013

	July 2013	August 2013	September 2013	October 2013	November 2013	December 2013	TOTAL
KENERGY	125,124	121,089	92,113	78,820	91,242	123,037	1,231,990
JACKSON PURCHASE	71,329	68,579	52,224	44,007	50,152	67,189	680,580
MEADE COUNTY	46,792	44,505	34,556	31,147	37,869	55,335	497,261
TOTAL MEMBER RURAL ENERGY	243,246	234,173	178,893	153,974	179,263	245,561	2,409,830
ACCURIDE	1,894	1,894	1,784	1,894	1,784	1,894	21,778
ALCOA	83	83	121	83	121	83	1,160
ALERIS	15,600	15,600	14,999	15,600	14,999	15,600	182,570
ALLIED (STEMPORT)	2,384	2,384	2,519	2,384	2,519	2,384	30,518
ARMSTRONG DOCK	1,530	694	863	1,096	1,124	1,506	16,246
ARMSTRONG EQUALITY	1,410	1,410	1,234	1,410	1,410	1,410	15,316
ARMSTRONG LEWIS CREEK	1,652	1,652	1,599	1,652	1,599	1,652	18,783
ARMSTRONG MIDWAY	1,551	1,551	1,572	1,551	1,572	1,551	20,090
ARVIN ROLL COATER	1,739	1,739	1,739	1,739	1,739	1,739	20,694
DOMTAR	14,657	14,657	10,638	10,993	10,638	10,993	136,757
DOTIKI	566	566	566	566	566	566	6,636
HOPKINS CO. COAL	174	174	174	174	174	174	1,969
KBI ALLOY	535	535	629	535	629	535	7,043
KIMBERLY CLARK	25,599	25,599	24,983	25,599	24,983	25,599	302,620
KMMC, Inc./P&M/Cochise	37	37	37	37	37	37	582
PATRIOT COAL	1,889	2,244	2,244	1,889	1,889	1,889	24,793
Shell Oil JP Industrials	1,250	1,250	1,250	1,250	1,250	1,250	15,000
SOUTHWIRE COMPANY	4,108	3,791	3,863	4,112	3,866	3,781	47,858
TYSON	5,528	5,528	5,220	5,528	5,220	5,528	63,146
VALLEY	778	778	778	778	809	809	9,470
TOTAL MEMBER IND'L ENERGY	82,964	82,165	76,809	78,869	76,926	78,979	943,027
ALCAN	268,316	268,316	259,661	268,316	259,661	268,316	3,201,778
CENTURY	351,436	215,396	-	-	-	-	2,618,764
TOTAL	945,961	800,050	515,363	501,160	515,850	592,855	9,173,399

Big Rivers ELECTRIC CORPORATION

DEMAND AND ENERGY BUDGET
2013 - 2014

BILLING DEMAND (MW) - 2014

	January 2014	February 2014	March 2014	April 2014	May 2014	June 2014
KENERGY	268.7	241.8	212.3	169.3	195.9	245.6
JACKSON PURCHASE	148.8	132.5	116.1	89.3	111.9	142.7
MEADE COUNTY	131.0	115.3	97.0	74.7	72.3	90.9
TOTAL MEMBER RURAL DEMAND	548.6	489.6	425.3	333.3	380.1	479.1
ACCURIDE	5.2	5.3	5.4	5.4	5.5	5.4
ALCOA	0.1	0.2	0.2	0.2	0.2	0.2
ALERIS	28.2	27.4	27.2	26.6	26.7	26.6
ALLIED (STEMPORT)	7.0	7.2	6.9	6.9	6.4	6.9
ARMSTRONG DOCK	5.4	5.2	4.7	4.3	4.2	4.1
ARMSTRONG EQUALITY	3.0	2.7	3.1	3.3	3.0	3.1
ARMSTRONG LEWIS CREEK	3.2	3.2	3.2	3.2	3.2	3.2
ARMSTRONG MIDWAY	3.7	3.7	3.8	3.5	3.3	3.5
ARVIN ROLL COATER	3.8	3.8	3.8	3.8	3.8	3.8
DOMTAR	15.0	15.0	15.0	15.0	15.0	15.0
DOTIKI	0.8	0.8	0.8	0.8	0.8	0.8
HOPKINS CO. COAL	0.3	0.5	0.4	0.4	0.4	0.4
KBI ALLOY	2.0	2.0	2.0	2.0	2.0	2.0
KIMBERLY CLARK	36.2	36.2	36.5	36.8	36.6	36.8
KMMC, Inc./P&M/Cochise	0.3	0.2	0.2	0.2	0.1	0.1
PATRIOT COAL	5.2	5.3	4.9	5.0	4.7	4.6
Shell Oil JP Industrials	3.4	3.4	3.4	3.4	3.4	3.4
SOUTHWIRE COMPANY	6.7	6.9	6.6	6.9	6.7	6.9
TYSON	9.1	9.0	9.1	10.0	10.5	10.0
VALLEY	2.0	2.0	2.0	1.8	2.0	1.9
TOTAL MEMBER NCP IND'L DEMAND	140.6	139.9	139.1	139.4	138.4	138.5
ALCAN	368.0	368.0	368.0	368.0	368.0	368.0
CENTURY	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	1,057	997	932	841	887	986

Case No. 2013-00535
Exhibit Barron-3

Big Rivers ELECTRIC CORPORATION

DEMAND AND ENERGY BUDGET
2013 - 2014

BILLING DEMAND (MW) - 2014

	July 2014	August 2014	September 2014	October 2014	November 2014	December 2014	TOTAL
KENERGY	256.6	275.9	223.5	173.8	196.1	247.2	2,706.7
JACKSON PURCHASE	149.1	162.1	118.3	97.3	105.7	136.9	1,510.7
MEADE COUNTY	95.0	103.3	80.6	70.2	81.2	117.9	1,129.6
TOTAL MEMBER RURAL DEMAND	500.8	541.3	422.4	341.3	383.1	502.1	5,346.9
ACCURIDE	5.5	5.4	5.5	5.5	5.4	5.5	65.0
ALCOA	0.2	0.2	0.2	0.2	0.2	0.2	2.1
ALERIS	26.7	26.6	26.7	26.7	26.6	26.7	322.5
ALLIED (STEMPORT)	6.4	6.9	6.4	6.4	6.9	6.4	80.6
ARMSTRONG DOCK	4.2	3.7	2.1	4.0	4.4	4.8	51.2
ARMSTRONG EQUALITY	3.2	3.1	3.2	3.2	3.2	3.2	37.2
ARMSTRONG LEWIS CREEK	3.2	3.2	3.2	3.2	3.2	3.2	38.4
ARMSTRONG MIDWAY	3.3	3.5	3.3	3.3	3.5	3.3	41.6
ARVIN ROLL COATER	3.8	3.8	3.8	3.8	3.8	3.8	45.0
DOMTAR	20.0	20.0	15.0	15.0	15.0	15.0	190.0
DOTIKI	0.8	0.8	0.8	0.8	0.8	0.8	9.6
HOPKINS CO. COAL	0.4	0.4	0.4	0.4	0.4	0.4	4.6
KBI ALLOY	2.0	2.0	2.0	2.0	2.0	2.0	24.0
KIMBERLY CLARK	36.6	36.8	36.6	36.6	36.8	36.6	439.3
KMMC, Inc./P&M/Cochise	0.1	0.1	0.1	0.1	0.1	0.1	1.6
PATRIOT COAL	4.5	5.0	5.0	4.5	4.5	4.5	57.7
Shell Oil JP Industrials	3.4	3.4	3.4	3.4	3.4	3.4	40.8
SOUTHWIRE COMPANY	6.7	6.9	6.4	7.1	6.7	6.5	81.0
TYSON	10.5	10.0	10.5	10.5	10.0	10.5	119.6
VALLEY	1.9	1.9	1.9	1.9	1.8	1.8	22.7
TOTAL MEMBER NCP IND'L DEMAND	143.2	143.5	136.4	138.5	138.4	138.6	1,674.6
ALCAN	368.0	368.0	368.0	368.0	368.0	368.0	4,416.0
CENTURY	0.0	0.0	0.0	0.0	0.0	0.0	-
TOTAL	1,012	1,053	927	848	889	1,009	11,437.5

Big Rivers ELECTRIC CORPORATION

DEMAND AND ENERGY BUDGET
2013 - 2014

ENERGY (MWh) - 2014

	January 2014	February 2014	March 2014	April 2014	May 2014	June 2014
KENERGY	128,021	107,365	97,726	77,348	86,504	114,462
JACKSON PURCHASE	68,728	56,226	52,267	42,252	48,881	63,833
MEADE COUNTY	56,469	47,785	40,695	30,671	32,481	41,984
TOTAL MEMBER RURAL ENERGY	253,218	211,376	190,689	150,270	167,867	220,279
ACCURIDE	1,744	1,602	1,823	1,784	1,894	1,784
ALCOA	86	78	99	121	83	121
ALERIS	14,931	14,375	15,269	14,999	15,600	14,999
ALLIED (STEMPORT)	2,797	2,711	3,015	2,519	2,384	2,519
ARMSTRONG DOCK	2,045	2,012	1,703	1,140	1,194	1,340
ARMSTRONG EQUALITY	997	1,038	1,267	1,299	1,198	1,234
ARMSTRONG LEWIS CREEK	1,652	1,492	1,652	1,599	1,652	1,599
ARMSTRONG MIDWAY	2,050	1,993	2,002	1,572	1,551	1,572
ARVIN ROLL COATER	1,739	1,570	1,739	1,739	1,739	1,739
DOMTAR	10,993	9,929	10,993	10,638	10,993	10,638
DOTIKI	544	493	573	542	543	544
HOPKINS CO. COAL	190	74	187	138	170	167
KBI ALLOY	655	548	651	629	535	629
KIMBERLY CLARK	25,301	23,565	25,831	24,983	25,599	24,983
KMMC, Inc./P&M/Cochise	92	83	60	48	40	37
PATRIOT COAL	2,173	2,386	2,293	2,244	2,005	1,648
Shell Oil JP Industrials	1,250	1,250	1,250	1,250	1,250	1,250
SOUTHWIRE COMPANY	4,174	3,681	4,159	3,950	4,299	4,073
TYSON	5,026	4,578	5,022	5,220	5,528	5,220
VALLEY	746	847	809	809	760	769
TOTAL MEMBER IND'L ENERGY	79,185	74,303	80,396	77,223	79,017	76,864
ALCAN	268,316	242,350	268,316	259,661	268,316	259,661
CENTURY	-	-	-	-	-	-
TOTAL	600,718	528,030	539,401	487,153	515,201	556,804

Big Rivers ELECTRIC CORPORATION

DEMAND AND ENERGY BUDGET

2013 - 2014

ENERGY (MWh) - 2014

	July 2014	August 2014	September 2014	October 2014	November 2014	December 2014	TOTAL
KENERGY	127,387	123,279	93,779	80,245	92,892	125,262	1,254,268
JACKSON PURCHASE	72,439	69,646	53,036	44,692	50,932	68,234	691,167
MEADE COUNTY	47,366	45,051	34,980	31,529	38,334	56,014	503,360
TOTAL MEMBER RURAL ENERGY	247,192	237,975	181,795	156,466	182,158	249,509	2,448,796
ACCURIDE	1,894	1,894	1,784	1,894	1,784	1,894	21,778
ALCOA	83	83	121	83	121	83	1,160
ALERIS	15,600	15,600	14,999	15,600	14,999	15,600	182,570
ALLIED (STEMPORT)	2,384	2,384	2,519	2,384	2,519	2,384	30,518
ARMSTRONG DOCK	1,530	694	863	1,096	1,124	1,506	16,246
ARMSTRONG EQUALITY	1,410	1,410	1,234	1,410	1,410	1,410	15,316
ARMSTRONG LEWIS CREEK	1,652	1,652	1,599	1,652	1,599	1,652	19,454
ARMSTRONG MIDWAY	1,551	1,551	1,572	1,551	1,572	1,551	20,090
ARVIN ROLL COATER	1,739	1,739	1,739	1,739	1,739	1,739	20,694
DOMTAR	14,657	14,657	10,638	10,993	10,638	10,993	136,757
DOTIKI	566	566	566	566	566	566	6,636
HOPKINS CO. COAL	174	174	174	174	174	174	1,969
KBI ALLOY	535	535	629	535	629	535	7,043
KIMBERLY CLARK	25,599	25,599	24,983	25,599	24,983	25,599	302,620
KMMC, Inc./P&M/Cochise	37	37	37	37	37	37	582
PATRIOT COAL	1,889	2,244	2,244	1,889	1,889	1,889	24,793
Shell Oil JP Industrials	1,250	1,250	1,250	1,250	1,250	1,250	15,000
SOUTHWIRE COMPANY	4,108	3,791	3,863	4,112	3,866	3,781	47,858
TYSON	5,528	5,528	5,220	5,528	5,220	5,528	63,146
VALLEY	778	778	778	778	809	809	9,470
TOTAL MEMBER IND'L ENERGY	82,964	82,165	76,809	78,869	76,926	78,979	943,699
ALCAN	268,316	268,316	259,661	268,316	259,661	268,316	3,159,206
CENTURY	-	-	-	-	-	-	-
TOTAL	598,472	588,456	518,265	503,652	518,745	596,804	6,551,701

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

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

DIRECT TESTIMONY

OF

JAMES V. HANER
VICE PRESIDENT ADMINISTRATIVE SERVICES

ON BEHALF OF

BIG RIVERS ELECTRIC CORPORATION

FILED: January 15, 2013

DIRECT TESTIMONY
OF
JAMES V. HANER

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DIRECT TESTIMONY
OF
JAMES V. HANER

I. INTRODUCTION

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

A. My name is James V. Haner. I am employed by Big Rivers Electric Corporation ("Big Rivers"), 201 Third Street, Henderson, Kentucky 42420, as Vice President Administrative Services.

Q. Please describe your job responsibilities.

A. I am responsible for oversight and management of the administrative services department, which includes human resources, corporate insurance, corporate safety, general services, and corporate files.

Q. Briefly describe your education and work experience.

A. I assumed my current responsibilities in July 1998, first as Manager of Human Resources and Corporate Services, and then as Vice President Administrative Services in December 2005. Prior to 1998, I held other positions in Administrative Services and, prior to 1991, several positions in Accounting where I began employment at Big Rivers on June 1, 1972. I have a Bachelor of Science in Accounting from the University of Kentucky. A summary of my professional experience is provided as Exhibit Haner-1.

Q. To what extent have you previously testified or otherwise participated in any proceedings before the Kentucky Public Service Commission ("Commission")?

A. I did not provide direct testimony (but did sponsor responses to certain information requests) in Big Rivers' last base rate case, Case No. 2011-00036. As Manager of Accounting prior to 1986, I had oversight responsibilities and participated directly in the preparation of other base rate cases, testifying in those cases and in fuel adjustment clause hearings before the Commission.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is (i) to describe the role of Administrative Services in the development of Big Rivers' labor and labor-related costs for the budget; (ii) to describe the determination of anticipated severance costs that are included in the Big Rivers budget; and (iii) to sponsor certain filing requirements from 807 KAR 5:001.

Q. Are you sponsoring any exhibits?

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

1. Exhibit Haner-1 Qualifications of James V. Haner
2. Exhibit Haner-2 Calculation of Severance Costs

III. LABOR & LABOR-RELATED COSTS

Q. Please provide an overview of the role of Administrative Services in the budget development process.

A. Administrative Services staff members collaborate with budget analysts and department managers across Big Rivers in the budget development process. In general, my staff and I work to develop values for headcount, wage rates, wage increase assumptions, and other compensation items. We also address benefits, including workers compensation, long-term disability, health, and life insurance, pension, and other costs. We assist in the development of the payroll burdens associated with these items and provide any other labor or labor-related information that is required of us for budget development.

Q. How are the department headcount totals developed for the budget?

A. The headcount totals are determined for each department by the department managers in collaboration with the budget analysts. Administrative Services reconciles the headcount to the organizational chart.

Q. How are the wage rates developed?

A. The beginning wage rates are the rates as of the December 31st immediately preceeding the budget year. They are the actual rates at the time the budget is being prepared, adjusted for any changes we know or anticipate will occur on or prior to that December 31st due to promotions, salary acceleration, and step rate increases. The rates for the budget year are the rates as of the immediately preceding December 31st, adjusted for the wage increase assumptions and the salary acceleration and step rate increases during the budget year.

Q. How are the wage increase assumptions developed?

A. The wage increase for bargaining employees is that set out in the labor agreements. The assumption for non-bargaining employees is based on the adjustment anticipated to be made in the salary structure, which can take into account movement in the consumer price index, nationally published survey data, and market pricing of positions.

Q. How are the overtime estimates developed?

A. Overtime factor estimates are provided by the department managers based on historical data, planned workloads and schedules, or other considerations applicable to specific departments.

Q. How are the health and life insurance cost estimates developed?

A. Medical and dental insurance costs for active employees are based on net premium-equivalent rates for the employees' coverage. Flexible spending account cost is based on Big Rivers' contribution to the account for those active employees on the medical coverage. Vision insurance cost is based on Big Rivers' contribution for single coverage. Post-retirement medical insurance expense is estimated by Big Rivers' consulting actuary. Post-employment medical insurance expense is based on the net-premium equivalent rates for disabled employees who remain on the coverage one year following their disability date, as well as medical trend and discount rates used by the consulting actuary in estimating post-retirement expense. Employee life insurance cost is based on base pay rates projected for January 1st of the budget year and the latest known insurance rate. Spouse and child life insurance cost is based on active employee group coverage and premium.

Q. How are the long-term disability insurance cost estimates developed?

A. Long-term disability insurance cost is based on base pay rates projected for January 1st of the budget year and the latest known insurance rate.

Q. How are the workers compensation insurance cost estimates developed?

A. The workers compensation insurance premium rates for the year preceding the budget year are adjusted by the percentage change anticipated for the budget year. The adjusted rates are applied to budgeted straight time labor to arrive at the expense estimate for the budget year.

Q. How are the pension cost estimates developed?

A. The 401(k) employer matching contribution is based on projected base pay, assuming a 60% match of the employees' contribution of 6% of base pay.

The non-elective, non-matching employer contribution into the retirement income or base contribution account of the retirement savings plan is based on projected pay for the budget year and a contribution rate for the average age of employees. The defined benefit retirement plan expense is estimated by Big Rivers' consulting actuary.

Q. How are the Federal Insurance Contributions Act ("FICA") cost estimates developed?

A. The FICA cost estimate is based on estimated wages in the budget year times the Medicare and Social Security tax rates for that year, subject to applicable Internal Revenue Service limits.

Q. How are the unemployment tax cost estimates developed?

A. The federal and state unemployment tax cost estimates are based on the respective taxable wage bases and rates for the budget year.

Q. How are the payroll burdens associated with Big Rivers' benefits developed?

A. The benefit amounts developed by Administrative Services that are to be expensed through the payroll burdening process are used by the budget department staff to calculate burden rates. They input the rates into Hyperion, a budgeting and reporting software application, for incorporation into the labor budget.

Q. What steps has Big Rivers taken to reduce or to otherwise mitigate future increases to the labor-related costs discussed above?

A. The most recent steps include (i) marketing of the long-term disability insurance coverage for 2013, resulting in a reduction in expense compared to remaining with the current provider; (ii) adjusting plan design for non-Medicare medical coverage, effective January 1, 2013, with increases in deductibles, out-of-pocket amounts, prescription drug co-payments, and employee contributions toward the cost of coverage, thus reducing Big Rivers' cost for the coverage; and (iii) revising the eligibility requirements for post-retirement medical coverage after 2013, with increases in the age requirement for some, and addition of a service requirement for others, thus reducing Big Rivers' expense and liability for post-retirement medical coverage. Big Rivers moved to a self-insured medical plan effective January 1, 2012, and closed its defined benefit retirement plans to new entrants or employees in 2008, both of which served to reduce expense.

IV. SEVERANCE COSTS

Q. Does Big Rivers anticipate any severance costs in the 2013-2014 timeframe?

A. Yes. Due to the circumstances described in the Direct Testimony of Mr. Robert W. Berry, Big Rivers anticipates that it will incur severance-related expenses in the 2013-2014 timeframe.

Q. What is the total amount of anticipated severance expense?

A. The budget includes a total of $4.6 million for severance expense. The way in which this amount is incorporated into the budget is explained in the Direct Testimony of Ms. DeAnna M. Speed.

Q. How is the total amount of anticipated severance expense calculated?

A. The production department identified those bargaining and non-bargaining positions anticipated to be eliminated with the idling of one of Big Rivers' power plants. Severance benefits budgeted include two weeks of base pay per year of service, with a minimum of eight weeks and a maximum of 52 weeks, and continuation of medical and dental insurance for the severance period. For the bargaining positions to be eliminated, it was assumed that employees 61 years of age or older would choose severance and that those less than 61 would choose to exercise their right under the labor agreement to displace less senior employees or fill vacancies at other power plants operated by Big Rivers. For the non-bargaining employees whose positions were anticipated to be eliminated and the bargaining employees anticipated to choose severance or identified for termination through the labor agreement displacement process, severance base pay was calculated using their years of service and their projected base pay rate as of December 1, 2013. The cost of medical and dental insurance continuation for the severance period was calculated using the net-premium equivalent rate for the employees' coverage. Severance expense includes base pay and the

FICA tax on that pay, and the cost calculated for continuation of insurance. The severance cost calculations are shown in Exhibit Haner-2.

Q. Are severance benefits for bargaining unit employees subject to collective bargaining?

A. Yes.

V. <u>FILING REQUIREMENTS</u>

Q. Are you sponsoring any of the answers provided in Tabs 1-62 which address Big Rivers' compliance with the fully forecast test period filing requirements under 807 KAR 5:001 and its various subsections?

A. Yes. I hereby incorporate and adopt those portions of Tabs 1-62 for which I am identified as the sponsoring witness.

VI. <u>CONCLUSION</u>

Q. What are your conclusions and recommendations to the Commission in this proceeding?

A. The labor and labor-related costs included in the Big Rivers budget are developed through a thorough and detailed process. Big Rivers uses conventional methods and relies on data from its benefit providers to derive its cost estimates. Big Rivers has taken steps to reduce the costs of providing benefits and continues to pursue additional cost mitigation efforts on a routine basis. Big Rivers' labor and labor-related costs are reasonable. In addition, for the reasons outlined by Mr. Berry, Big Rivers anticipates incurring a severance cost of $4.6 million. This cost was determined using a sound methodology. The Commission should accept these costs as presented and as utilized in the modeling of Big Rivers' financials for the fully forecasted test period

Q. Does this conclude your testimony?

A. Yes.

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2012-00535

<u>VERIFICATION</u>

I, James V. Haner, verify, state, and affirm that I prepared or supervised the preparation of my testimony filed with this Verification, and that testimony is true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

James V. Haner

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by James V. Haner on this the 8th day of January, 2013.

Notary Public, Ky. State at Large
My Commission Expires 8-9-14

Professional Summary

James V. Haner
Vice President Administrative Services
Big Rivers Electric Corporation
201 3rd Street
Henderson, Kentucky 42420
(270) 844-6110

Professional Experience

Big Rivers Electric Corporation 1972 to present

Vice President Administrative Services

Acting Vice President Finance and Administrative Services

Manager Human Resources and Corporate Services

Manager Corporate Services, Insurance, and Loss Control

Manager Taxes, Insurance, and Budgets

Manager Accounting

Supervisor General Accounting

Chief Accountant

Senior Accountant

Accountant

Education

Bachelor of Science in Accounting

University of Kentucky

Big Rivers Electric Corporation
Case No. 2012-00535
Severance Calculation

	12/1/13	Severance		Cvg at Active Rate			Inactive	Budget	11/12	Severance			
Employee	Pay	Weeks	Total	Mos	2013	2014	Cvg Mos	2013	2013	Medicare	Soc Sec	FICA	TOTAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1	63,170	52	63,170	5	581	2,324	7	78,311	71,785	63,170	41,915	3,515	69,590
2	60,174	16	18,515	3	1,170	2,340	1	75,643	69,339	18,515	18,515	1,416	23,441
3	70,304	52	70,304				12	78,547	72,001	70,304	41,699	3,605	73,909
4	70,304	52	70,304				12	80,093	73,419	70,304	40,281	3,517	73,821
5	63,170	52	63,170				12	64,015	58,680	63,170	55,020	4,327	67,497
6	70,304	52	70,304				12	80,093	73,419	70,304	40,281	3,517	73,821
7	70,304	52	70,304				12	80,093	73,419	70,304	40,281	3,517	73,821
8	63,170	52	63,170				12	78,311	71,785	63,170	41,915	3,515	66,685
9	59,426	52	59,426				12	76,233	69,880	59,426	43,820	3,579	63,005
10	60,174	52	60,174				12	76,409	70,042	60,174	43,658	3,579	63,753
11	59,426	52	59,426				12	67,693	62,052	59,426	51,648	4,064	63,490
12	63,939	8	9,837	2	1,170	1,170		82,753	75,857	9,837	9,837	753	12,930
13	70,304	52	70,304				12	80,093	73,419	70,304	40,281	3,517	73,821
14	59,426	8	9,142	2	1,636	1,636		66,212	60,694	9,142	9,142	699	13,113
15	70,304	52	70,304	8	1,170	8,189	4	87,166	79,902	70,304	33,798	3,115	82,778
16	60,174	48	55,545				11	74,108	67,932	55,545	45,768	3,643	59,188
17	59,426	8	9,142	2	1,636	1,636		66,338	60,810	9,142	9,142	699	13,113
18	52,936	52	52,936				12	64,646	59,259	52,936	52,936	4,050	56,986
19	70,304	52	70,304				12	78,547	72,001	70,304	41,699	3,605	73,909
20	70,304	52	70,304	5	1,170	4,679	7	82,894	75,986	70,304	37,714	3,358	79,511
21	52,936	22	22,396				5	64,646	59,259	22,396	22,396	1,713	24,109
22	70,304	52	70,304				12	78,547	72,001	70,304	41,699	3,605	73,909
23	63,939	8	9,837	2	1,636	1,636		77,900	71,408	9,837	9,837	753	13,862
24	59,426	8	9,142	2	563	563		68,565	62,851	9,142	9,142	699	10,967
25	52,208	8	8,032	2	1,636	1,636		57,407	52,623	8,032	8,032	614	11,918

Big Rivers Electric Corporation
Case No. 2012-00535
Severance Calculation

	12/1/13	Severance		Cvg at Active Rate			Inactive	Budget	11/12	Severance			TOTAL
Employee	Pay	Weeks	Total	Mos	2013	2014	Cvg Mos	2013	2013	Medicare	Soc Sec	FICA	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
26	59,426	8	9,142	2	1,068	1,068		76,233	69,880	9,142	9,142	699	11,977
27	57,616	8	8,864	2	1,068	1,068		73,862	67,707	8,864	8,864	678	11,678
28	52,208	8	8,032	2	1,068	1,068		63,341	58,063	8,032	8,032	614	10,782
29	59,426	8	9,142	2	28	28		74,858	68,620	9,142	9,142	699	9,897
30	70,304	52	70,304				12	90,897	83,322	70,304	30,378	2,903	73,207
31	63,939	8	9,837	2	1,636	1,636		70,928	65,017	9,837	9,837	753	13,862
32	70,304	52	70,304	2	581	581	10	90,003	82,503	70,304	31,197	2,954	74,420
33	60,174	52	60,174				12	76,409	70,042	60,174	43,658	3,579	63,753
34	59,426	8	9,142	2	1,636	1,636		76,991	70,575	9,142	9,142	699	13,113
35	63,939	8	9,837	2	1,636	1,636		69,948	64,119	9,837	9,837	753	13,862
36	52,208	8	8,032	2	0	0		64,218	58,867	8,032	8,032	614	8,646
37	70,304	52	70,304	9	1,170	9,359	3	80,093	73,419	70,304	40,281	3,517	84,350
38	60,174	52	60,174				12	75,643	69,339	60,174	44,361	3,623	63,797
39	59,426	8	9,142	2	1,636	1,636		72,605	66,555	9,142	9,142	699	13,113
40	70,304	52	70,304	3	1,636	3,271	9	82,894	75,986	70,304	37,714	3,358	78,569
41	60,174	49	56,702				11	74,108	67,932	56,702	45,768	3,660	60,362
42	59,426	8	9,142	2	1,636	1,636		76,991	70,575	9,142	9,142	699	13,113
43	59,426	9	10,285	2	1,100	1,100		76,233	69,880	10,285	10,285	787	13,272
44	70,304	52	70,304				12	78,547	72,001	70,304	41,699	3,605	73,909
45	52,208	8	8,032	2	563	563		62,901	57,659	8,032	8,032	614	9,772
46	51,334	8	7,898	2	1,636	1,636		62,962	57,715	7,898	7,898	604	11,774
47	60,174	52	60,174				12	75,643	69,339	60,174	44,361	3,623	63,797
48	70,304	52	70,304				12	80,093	73,419	70,304	40,281	3,517	73,821
49	70,304	52	70,304				12	80,093	73,419	70,304	40,281	3,517	73,821
50	59,426	52	59,426	10	1,636	14,721	2	66,199	60,682	59,426	53,018	4,149	79,932

Big Rivers Electric Corporation
Case No. 2012-00535
Severance Calculation

	12/1/13	Severance		Cvg at Active Rate			Inactive	Budget	11/12	Severance			
Employee	Pay	Weeks	Total	Mos	2013	2014	Cvg Mos	2013	2013	Medicare	Soc Sec	FICA	TOTAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
51	70,304	52	70,304				12	87,166	79,902	70,304	33,798	3,115	73,419
52	70,304	52	70,304				12	87,166	79,902	70,304	33,798	3,115	73,419
53	60,174	52	60,174				12	74,108	67,932	60,174	45,768	3,710	63,884
54	39,534	52	39,534	12	1,079	11,870		39,686	36,379	39,534	39,534	3,024	55,507
55	58,625	52	58,625	12	1,653	18,183		61,346	56,234	58,625	57,466	4,413	82,874
56	114,231	20	43,935	5	1,653	6,612		114,670	105,114	43,935	8,586	1,169	53,369
57	90,338	8	13,898	2	0	0		92,993	85,244	13,898	13,898	1,063	14,961
58	81,902	25	39,376	6	569	2,846		84,309	77,283	39,376	36,417	2,829	45,620
59	90,338	52	90,338	12	1,182	13,006		92,993	85,244	90,338	28,456	3,074	107,600
60	90,338	52	90,338	12	569	6,261		92,993	85,244	90,338	28,456	3,074	100,242
61	90,338	52	90,338	12	1,182	13,006		96,838	88,768	90,338	24,932	2,856	107,382
62	90,338	52	90,338				12	96,838	88,768	90,338	24,932	2,856	93,194
63	90,338	29	50,381	7	1,653	9,918		92,993	85,244	50,381	28,456	2,495	64,447
64	90,338	49	85,126	11	569	5,692		92,993	85,244	85,126	28,456	2,999	94,386
65	81,902	52	81,902	12	1,182	13,006		83,612	76,644	81,902	37,056	3,485	99,575
66	90,338	52	90,338	12	1,182	13,006		90,685	83,128	90,338	30,572	3,205	107,731
67	90,338	52	90,338	12	1,182	13,006		94,531	86,653	90,338	27,047	2,987	107,513
68	80,267	8	12,349	2	1,653	1,653		78,556	72,010	12,349	12,349	945	16,600
69	69,972	52	69,972				12	72,806	66,739	69,972	46,961	3,926	73,898
70	90,338	52	90,338	12	1,653	18,183		92,993	85,244	90,338	28,456	3,074	113,248
71	90,338	52	90,338	12	1,182	13,006		96,838	88,768	90,338	24,932	2,856	107,382
72	48,173	52	48,173	12	569	6,261		48,447	44,410	48,173	48,173	3,685	58,688
73	39,534	26	19,767	6	1,182	5,912		39,686	36,379	19,767	19,767	1,512	28,373
74	90,338	52	90,338	12	1,653	18,183		96,838	88,768	90,338	24,932	2,856	113,030
75	58,625	8	9,019	2	1,653	1,653		61,209	56,108	9,019	9,019	690	13,015

Big Rivers Electric Corporation
Case No. 2012-00535
Severance Calculation

	12/1/13	Severance		Cvg at Active Rate			Inactive	Budget	11/12	Severance			
Employee	Pay	Weeks	Total	Mos	2013	2014	Cvg Mos	2013	2013	Medicare	Soc Sec	FICA	TOTAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
76	90,338	52	90,338	12	1,182	13,006		92,993	85,244	90,338	28,456	3,074	107,600
77	90,338	16	27,796	4	1,653	4,959		92,461	84,756	27,796	27,796	2,126	36,534
78	44,522	52	44,522	12	569	6,261		44,693	40,969	44,522	44,522	3,406	54,758
79	90,338	52	90,338	12	1,653	18,183		96,838	88,768	90,338	24,932	2,856	113,030
80	90,338	8	13,898	2	1,653	1,653		95,227	87,291	13,898	13,898	1,063	18,267
81	39,534	45	34,212				11	39,686	36,379	34,212	34,212	2,617	36,829
82	58,625	8	9,019	2	569	569		60,347	55,318	9,019	9,019	690	10,847
83	90,338	15	26,059	4	569	1,708		96,033	88,030	26,059	25,670	1,969	30,305
TOTAL	5,680,088		4,033,164		63,150	306,054						206,705	**4,609,073**

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

DIRECT TESTIMONY
OF
TED J. KELLY

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DIRECT TESTIMONY
OF
TED J. KELLY

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Ted J. Kelly, and my business address is 9400 Ward Parkway, Kansas City, Missouri, 64114.

Q. What is your occupation?

A. I am a Principal at the firm of Burns & McDonnell. I currently serve as a Senior Project Manager and Principal in the company's Business and Technology Services Division.

Q. How long have you been associated with the firm Burns & McDonnell?

A. I have been continuously employed by the firm since July 1998. Prior to that, I was employed with another major engineering firm from January 1978 to July 1998. During the period August 1981 to May 1983, I was a full time student at Indiana University.

Q. What is your education background?

A. I am a graduate of the Missouri University of Science & Technology (formerly, University of Missouri at Rolla), with a Bachelor of Science Degree in Economics and a minor in Engineering Management. I am also a graduate of Indiana University with a Master's Degree in Business Administration with emphasis in Utility Regulation and Management.

Q. What is your professional experience?

A. I have been responsible for numerous engagements involving electric, gas and other utility services. Clients served include cooperative utilities, publicly owned utilities, investor owned utilities, customers of such utilities, municipalities and regulatory agencies. During the course of these engagements, I have been responsible for the preparation and presentation of studies involving valuation, depreciation, cost of service, rate design, pricing, financial feasibility, cost of capital, and other utility financial, economic and management issues.

Q. What is the nature of the business of Burns & McDonnell?

A. Burns & McDonnell is a full-service engineering, architecture, construction, environmental and consulting solutions firm. Our multi-disciplined staff of more than 3,500 employee-owners includes engineers, architects, construction managers, developers, estimators, accountants, economists, technicians, and financial analysts representing virtually all design disciplines. Burns & McDonnell has provided comprehensive construction, engineering, consulting and management services to utility, industrial and governmental clients since 1898. The firm specializes in engineering, consulting and construction associated with utility services including electric, gas, water, wastewater, waste disposal, and telecommunications.

Service engagements consist principally of investigations and reports, design and construction, feasibility analyses, cost studies, rate and financial reports, valuation and depreciation studies, reports on operations and general consulting services. We plan, design, permit, construct and manage facilities throughout the United States and numerous foreign countries.

Q. For whom are you testifying in this proceeding?

A. I am testifying on behalf of Big Rivers Electric Corporation ("Big Rivers").

Q. Have you ever testified before this Commission or any other state or federal regulatory agency?

A. I have testified before the Kentucky Public Service Commission (the "Commission") in Big Rivers' previous rate case, Case No. 2011-00036, and I have testified before the Texas Public Utility Commission and the Kansas Corporation Commission. In addition, I assisted in the preparation of testimony submitted to the Wyoming Public Service Commission, the New York Public Service Commission, and the Connecticut Department of Public Utility Control.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. I sponsor the Burns & McDonnell Report on the Comprehensive Depreciation Rate Study ("the 2012 Depreciation Study") prepared for Big

Rivers, a true and accurate copy of which is attached hereto as Exhibit Kelly-1. The Study was performed for all of Big Rivers' facilities accounted for in accordance with Rural Utilities Service ("RUS") Bulletin 1767B-1, Uniform System of Accounts. The 2012 Depreciation Study is based on historical plant records of Big Rivers as of July 31, 2012. It was initiated and completed as a requirement for Big Rivers' filing for a general adjustment in its rates.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

1. Exhibit Kelly-1 – 2012 Depreciation Study and
2. Exhibit Kelly-2 – Burns & McDonnell Letter dated November 28, 2012.

III. 2012 DEPRECIATION STUDY

Q. Did you prepare the 2012 Depreciation Study?

A. Yes. I personally prepared portions of the 2012 Depreciation Study and the entire study was prepared under my supervision and direction.

Q. What is your professional experience in the field of depreciation?

A. I have prepared and supervised the preparation of numerous depreciation rate studies and useful life analyses for cooperative utilities and publicly-owned utilities.

Q. When was the last depreciation rate study completed for Big Rivers?

A. The last depreciation rate study was completed for Big Rivers by Burns & McDonnell in 2010 and filed with the RUS in February of 2011 (the "2010 Depreciation Study") in connection with Big Rivers' previous rate case, Case No. 2011-00036.

Q. What is depreciation?

A. The FERC and RUS Uniform System of Accounts define depreciation as:

> The loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, changes in the art, and changes in demand and requirements of public authorities.

A. Scope and Purpose

Q. What was the scope and purpose of the 2012 Depreciation Study?

A. The 2012 Depreciation Study was conducted to analyze the service life characteristics, net salvage indications, and depreciation reserve status based on historical data from Big Rivers' Continuing Property Records ("CPR") system data, and then to derive appropriate depreciation rates for Big Rivers' system plant in service.

B. Findings and Conclusions

Q. What are your findings and conclusions?

A. Based on the results of the Burns & McDonnell analysis, we find that Big Rivers should pursue approval and implementation of the proposed depreciation rates for each RUS account as presented on page ES-6 of the Study. These depreciation rates will result in an increase in annual depreciation expense of approximately $1.6 million per year (3.7 percent) as shown in Table ES-1 of the 2012 Depreciation Study. (*See* Exhibit Kelly-1, p. ES-6.)

C. Study Approach

Q. What was Burns & McDonnell's overall approach to meeting the requirements of the 2012 Depreciation Study?

A. First, Burns & McDonnell performed the following tasks:

1. Obtained information on the operating history, outages, operating expenses and generation statistics for all of the generation assets;
2. Obtained the property account records for all of Big Rivers' generation, transmission and general plant assets detailing original property cost, accumulated depreciation, additions and retirements;
3. Gathered data and information related to current staffing, maintenance procedures, scheduled maintenance, capital

expenditures, and capital projects for generation, transmission and general plant assets;

4. Reviewed the data and information provided; and
5. Compared the performance statistics of Big Rivers' generation units to industry standards.

Q. What was the next major step in your approach?

A. Burns & McDonnell relied substantially on the performance of previously completed physical site observations of the generation and transmission facilities by experienced power plant design engineers and transmission system engineers, respectively, performed in connection with the 2010 Depreciation Study. I personally participated in the site inspections and staff interviews in 2010 and in a conference call pertaining to the current condition of Big Rivers' generation and transmission facilities conducted in the completion of the 2012 Depreciation Study. Generally, the previously completed site visits included observation of the equipment and facilities and discussion with Big Rivers' staff and included the following activities:

1. Observation of Big Rivers' generating and transmission plant equipment and facilities;
2. Evaluation of the physical condition of the equipment and facilities;
3. Interviews of Big Rivers' generation and transmission operating and maintenance staff;

4. Review of each facility's organization structure, procedures, and staffing levels;
5. Evaluation of Big Rivers' generation and transmission operating and maintenance practices;
6. Assessment of Big Rivers' generation and transmission operating and maintenance reports;
7. Collection of pertinent cost and operating data records;
8. Collection of environmental data; and
9. Development of facilities descriptions.

The previously completed site visits were conducted at each of Big Rivers' production facilities, representative transmission substations, representative transmission lines, and the headquarters offices in Henderson, Kentucky. Key production, transmission, and accounting staff were interviewed and the condition of the facilities was assessed during these site visits. The site observations of the system facilities did not include any internal inspections or examinations, environmental testing, or completion of any performance tests on the equipment and facilities. No system, structural, pipe stress, or other mathematical modeling analysis was included in the scope of the facilities observations.

The conference call completed in connection with the 2012 Depreciation Study were held to discuss the current condition of Big Rivers' generation and transmission facilities and to review operations and maintenance of said facilities since the completion of the 2010 Depreciation Study.

After completing the inspections and interviews, Burns & McDonnell engineers applied their experience and engineering judgment in developing an Engineering Assessment for each of Big Rivers' generating facilities and approximating the remaining lives of each asset. (*See* 2012 Depreciation Study, Exhibit Kelly-1, Part II – Engineering Assessment.)

Q. How did you develop the depreciation rates?

A. The projected remaining useful lives of the various transmission assets and generating assets for each plant from the Engineering Assessment were then factored into the depreciation rate analysis performed by Burns & McDonnell's depreciation consultants. The 2012 Depreciation Study included analysis of the service life characteristics, projected net salvage values, and depreciation reserves for the generating assets, as well as for the transmission and general plant assets. The resulting depreciation rates are shown in Table ES-1 of the 2012 Depreciation Study. (*See* Exhibit Kelly-1, p. ES-6.)

Q. In preparing the 2012 Depreciation Study, did you follow generally accepted accounting practices in the field of depreciation?

A. Yes.

D. Report Contents

Q. What are the contents of the 2012 Depreciation Study report?

A. Part I, Introduction, discusses Big Rivers, the purpose of the 2012 Depreciation Study, the project approach and sources of data. Part II, Engineering Assessment, provides a summary review of the engineering assessment of the Big Rivers plant assets in service as of July 31, 2012. Part III, Depreciation Rate Analysis, describes the methodology and the analysis performed in the formulation of proposed new depreciation rates for the electric generation, transmission, and general assets of Big Rivers. Part IV provides the Summary & Conclusions.

Q. Please describe the Engineering Assessment.

A. The Engineering Assessment provides an engineering assessment of Big Rivers' generation and transmission plant assets in service as of July 31, 2012. The following activities were conducted to examine Big Rivers' generation and transmission plant assets from an engineering perspective:

1. A discussion of each production facility's basic design and equipment;
2. Previously completed on-site reviews and analyses of each production facility's current operating condition;
3. Conference call pertaining to the current condition of Big Rivers' generation and transmission facilities;
4. An analysis of each production facility's historical performance;

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

Two"). The Green Plant includes two units that are each significantly larger than the units at either the Reid Plant or the HMP&L Station Two. Green Plant Unit 1 is rated for net continuous capacity of 231 MW and Green Plant Unit 2 has a rated net capacity of 223 MW. Unit 1 began commercial operation in 1979 and Unit 2 became operational in 1981. Both units at the Green Plant are coal-fired steam generating units with Babcock & Wilcox boilers providing maximum steam capacity of 1,930,000 pounds per hour. Green Plant Unit 1 is equipped with a General Electric turbine-generator with a nameplate rating of 242,105 kW. Green Plant Unit 2 includes a Westinghouse turbine-generator rated at 242,133 kW.

Q. How has the Green Plant operated?

A. Burns & McDonnell reviewed the Green Plant's historical operating performance to verify that the generating units have competitive heat rates and are capable of providing the necessary level of reliability to meet Big Rivers' electric production requirements. Both Green Plant units have been performing well. The 2011 adjusted net heat rate was [redacted] Btu per kWh and [redacted] Btu per kWh for Green Plant Units One and Two, respectively, which is competitive with other coal fired power plants in the region. The availability of the units has also been good. Green Plant Unit 1 has a seven year average Equivalent Forced Outage Rate ("EFOR") of 2.1 percent, while Green Plant Unit 2 has a seven year average EFOR of 1.5 percent.

Q. What is the estimated remaining useful life for the Green Plant?

A. Green Plant Unit 1 and Unit 2 are both in excellent condition for their age and service requirements. Provided that Big Rivers will be able to perform future major maintenance in a manner consistent with prudent utility operations, there is no reason, from a mechanical engineering perspective, that this facility cannot remain in service another 20 to 27 years (depending on its operation). 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 the units.

ii. HMP&L Station Two

Q. Describe the HMP&L Station Two facility.

A. HMP&L Station Two is also located on the plant site near Sebree, Kentucky, along with the Reid Plant and the Green Plant. HMP&L Station Two is owned by the City of Henderson, Kentucky (the "City") through its municipal utility, Henderson Municipal Power & Light. Big Rivers operates HMP&L Station Two on behalf of the City. HMP&L Station Two includes two units similar in size to the three units at the Big Rivers Kenneth C. Coleman Plant. HMP&L Unit 1 is rated for net continuous capacity of 153 MW, and HMP&L Unit 2 has a rated net capacity of 159 MW. HMP&L Unit 1 began commercial operations in 1973, and HMP&L Unit 2 began commercial operations in 1974. Both HMP&L Station Two units are coal-fired steam generating units with Riley boilers having steam flow capacity of 1,180,000 pounds per hour. HMP&L Unit 1 is equipped with a General Electric turbine-generator with nameplate rating for the turbine of 175,984 kW. HMP&L Unit 2 includes a Westinghouse turbine-generator rated at 178,724 kW.

Q. How has HMP&L Station Two been operated?

A. Burns & McDonnell reviewed HMP&L Station Two's historical operating performance to verify that the generating units have competitive heat rates and are capable of providing the level of reliability necessary to meet Big Rivers' electric production requirements. Both HMP&L Station Two units have been performing well. The 2011 adjusted net heat rate was [redacted] Btu per kWh and [redacted] Btu per kWh for HMP&L Units One and Two, respectively, which is competitive with other coal fired plants in the region. HMP&L Unit 1 has a seven year average EFOR of 7.7 percent, while HMP&L Unit 2 has a seven year average EFOR of 5.1 percent.

Q. What is the estimated remaining useful life for the HMP&L Station Two facility?

A. The HMP&L Station Two units are in excellent condition for their age and service requirements. Provided that Big Rivers will be able to perform future major maintenance in a manner consistent with prudent utility operations, there is no reason, from a mechanical engineering perspective, that HMP&L Station Two cannot remain in service another 16 to 21 years (depending on its operation). 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 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 the units.

iii. Robert A. Reid Plant

Q. Describe the Robert A. Reid Plant.

A. The Robert A. Reid Plant (the "Reid Plant")is also located on the plant site near Sebree, Kentucky. The Reid Plant steam turbine generating unit includes a Riley boiler with a steam flow capacity of 690,000 pounds per hour and a General Electric turbine-generator with nameplate capacities of 66,000 kilowatts (kW) for the turbine and 96,000 kVA for the generator. The unit began commercial operation in 1966 and is currently rated at 65 MW.

Q. How has the Reid Plant been operated?

A. Burns & McDonnell reviewed the Reid Plant's historical operating performance to verify that the generating unit has competitive heat rates and is capable of providing the level of reliability necessary to meet Big Rivers' electric production requirements. The Reid Plant has performed commendably over the years. However, the unit had one of the highest heat rates on Big Rivers' system. The 2011 adjusted net heat rate for the unit was reported to be [redacted] Btu per kWh. This is relatively high for coal fired power plants in that region of the country, which is why the unit is primarily used for capacity and dispatched mostly as a peaking unit and for market sales. In addition, the seven year average EFOR of 21.2 percent is considered high when compared to other coal fired power plants in the region.

Q. What is the estimated remaining useful life for the Reid Plant?

A. The Reid Plant has not been run as many hours per year as other facilities and is in excellent condition for its age. Provided that Big Rivers will be able to perform future major maintenance in a manner consistent with prudent utility operations, there is no reason, from a mechanical engineering perspective, that the Reid Plant cannot remain in service another 12 years or longer (depending on its operation). 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 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 the units.

iv. D. B. Wilson Plant

Q. Describe the D.B. Wilson Plant.

A. The D. B. Wilson Plant ("Wilson Plant") is located at Island, Kentucky, approximately 55 miles from Henderson, Kentucky. The Wilson Plant consists of a single 417 MW unit commercialized in 1986. It is the newest and largest generating unit on the Big Rivers electric system. The Wilson Plant site is configured for installation of one or more additional units; therefore, the Wilson Plant facilities (such as coal handling, water supply, ash handling, and sludge disposal) all have more than adequate capacity for the current operating requirements.

Q. How has the Wilson Plant been operated?

A. Burns & McDonnell reviewed the Wilson Plant's historical operating performance to verify that the generating unit has a competitive heat rate and is capable of providing the level of reliability necessary to meet Big Rivers' electric production requirements. The Wilson Plant has been performing well. The 2011 adjusted net heat rate was only [redacted] Btu per kWh, which is competitive with other coal fired power plants in the region. The seven year average EFOR was 4.6 percent.

Q. What is the estimated remaining useful life for the Wilson Plant?

A. The details provided for the Wilson Plant are the most comprehensive and complete of any of the Big Rivers facilities. The Wilson Plant is in very good condition for its age and service requirements. Provided that Big Rivers will be able to perform future major maintenance in a manner consistent with prudent utility operations, there is no reason, from a mechanical engineering perspective, that the Wilson Plant cannot remain in service another 29 to 38 years (depending on its operation). 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 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 the units.

v. Kenneth C. Coleman Plant

Q. Describe the Kenneth C. Coleman Plant.

A. The Kenneth C. Coleman Plant (the "Coleman Plant") consists of three coal-fired, steam turbine generating units located near Hawesville, Kentucky, approximately 60 miles east of Henderson, Kentucky. The Coleman Plant is located on the west bank of the Ohio River. The land to the south is occupied by Century Aluminum and is the site of an aluminum reduction plant, a primary customer of power from the Coleman Plant.

The Coleman Plant is located on the flood plain of the Ohio River and operation could be affected by extreme flood levels. In the past, the Coleman Plant has experienced temporary isolation due to flooding of local access roads. However, the main plant area is located at a sufficient elevation to ensure that 100-year floods should not affect the plant's generation capabilities. Although a flood in excess of 100-year levels potentially could cause temporary interruptions of generating capability, this would not be anticipated to result in major disaster.

Coleman Plant Unit 1 was commercialized in 1969 and is rated for 150 MW of net capacity. The unit is equipped with a Foster Wheeler boiler capable of producing 1,220,000 pounds per hour of steam, and a Westinghouse turbine-generator with nameplate capacity of 160,000 kW. Coleman Plant Unit 2 was commercialized in 1970 and is rated for 138 MW of net capacity. The unit is equipped with a Foster Wheeler boiler capable of producing 1,220,000 pounds per hour of steam, and a Westinghouse turbine-generator with nameplate capacity of 160,000 kW. Coleman Plant Unit 3 was commercialized in 1972 and is rated for 155 MW of net capacity. The unit is equipped with a Riley boiler capable of producing 1,160,000 pounds per hour of steam, and a General Electric turbine-generator with nameplate capacity of 160,000 kW.

Q. How has the Coleman Plant been operated?

A. Burns & McDonnell reviewed the Coleman Plant's historical operating performance to verify that the generating units have competitive heat rates and are capable of providing the level of reliability necessary to meet Big Rivers' electric production requirements. All three Coleman units have been performing well. Coleman Units 1, 2, and 3 had 2011 adjusted net heat rates of [redacted], [redacted] and [redacted] Btu per kWh, respectively. The availability of the units has also been good. Coleman Unit 1 had a seven year average EFOR of 4.8 percent, Coleman Unit 2 had a seven year average EFOR of 2.7 percent, and Coleman Unit 3 had a seven year average EFOR of 5.9 percent.

Q. What is the estimated remaining useful life for the Coleman Plant?

A. Coleman Plant Units 1, 2, and 3 are in good condition for their age and type. Provided that Big Rivers will be able to perform future major maintenance in a manner consistent with prudent utility operations, there is no reason, from a mechanical engineering perspective, that the Coleman Plant cannot remain in service another 11 to 21 years (depending on its operation). 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 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 the units.

vi. Robert A. Reid Combustion Turbine

Q. Describe the Robert A. Reid combustion turbine.

A. The Robert A. Reid Combustion Turbine (the "Reid CT") is a General Electric Frame 7 combustion turbine placed in operation in 1976, with a net output rating of 65 MW. It is capable of firing #2 fuel oil or natural gas. Considered part of the Reid Plant, this unit is also located at the Sebree, Kentucky site with the HMP&L Station 2 and the Green Plant.

Q. How has the Reid CT been operated?

A. The Reid CT has been operated less than 1,000 hours over the last three years combined.

Q. What is the estimated remaining useful life for the Reid CT?

A. The relatively low number of operating hours for the Reid CT indicates that it should provide reasonably available capacity for a number of years into the future provided that Big Rivers will be able to perform future major maintenance in a manner consistent with prudent utility operations.

F. Transmission Assets

Q. Was an engineering assessment conducted on the transmission assets?

A. Yes. The following efforts were conducted to examine Big Rivers' major electric substation assets in service from an engineering perspective:

1. Review of Big Rivers' retirement records and history;
2. Analysis of current operating and maintenance programs as well as each facility's current operating conditions;
3. Analysis of the external or environmental factors that may impact the depreciation rates; and
4. Estimation of the remaining service life of major transmission facilities.

Q. What is the estimated remaining useful life for the transmission system and substations?

A. Estimated remaining useful lives for Big Rivers' transmission assets were based primarily on the transmission engineer's professional judgment based on experience and national industry standards regarding the expected useful life of major electric substation equipment.

- The Reid EHV substation is approximately 30 years old. Assuming a continued level of maintenance on the substation, the Reid EHV substation as a whole can be expected to function properly for an additional 27 to 28 years.
- The Coleman EHV substation is approximately 25 years old. Assuming a continued level of maintenance on the substation, the

Coleman EHV substation as a whole can be expected to function properly for an additional 32 to 33 years.

- The Wilson EHV substation is approximately 30 years old. Assuming a continued level of maintenance on the substation, the Wilson EHV substation as a whole can be expected to function properly for an additional 27 to 28 years.
- The Hancock substation is approximately 42 years old. Typically, substation transformers and circuit breakers are replaced any time after 40 years of useful life. However, given regular and proper maintenance, this equipment can last between 50 and 60 years. Brown insulators are considered obsolete by industry standards, and may need to be considered as part of future maintenance work. However, assuming a continued level of maintenance on the substation, the Hancock substation appears to be in good working order and should continue to function properly for an additional 17 to 18 years.
- The Hardinsburg substation is 44 years old. Typically, substation transformers and circuit breakers are replaced any time after 40 years of useful life. However, given regular and proper maintenance, this equipment can last between 50 and 60 years. Assuming a continued level of maintenance on the substation, the Hardinsburg

substation appears to be in good working order and should continue to function properly for an additional 17 to 18 years.

Q. How were the remaining useful lives of these assets incorporated into the depreciation analysis?

A. The current best estimates of future retirement dates for each generating station as described above were used as inputs to the Life Span model along with the actuarial analysis and engineers' judgment for each plant account. The life of these individual units can vary based on a number of factors including but not limited to operating hours and maintenance. The Green, HMP&L Station Two and Coleman facilities have multiple units, but are forecasted to retire in the same year. This is reasonable for three reasons. First, the units were installed within two to three years of each other. Second, most plant accounts are assigned to the entire generating station, not to individual units of the facility. Most importantly, it is realistic to assume that the entire facility would shut down before significant demolition activities begin to occur. Piecemeal removal at an operating facility would be costly and much of the plant infrastructure would need to remain in service in order to maintain the last unit's ability to function.

Account 312 contains some much newer environmental compliance assets such as scrubber equipment that have a shorter expected life than the other assets in Account 312. These assets are shown in Account 312 A-K. This is primarily due to the caustic nature of scrubber operations. As such, scrubber equipment dealing with sulfur dioxide removal and related piping will be expected to have a shorter life than that expected for the vast majority of the production plant. That life expectancy is directly related to the design, wear and tear from variable amounts of daily operation, and the levels of removal based on the particular coal mix being burned.

In addition, assets such as mist eliminator panels and slag grinders with even shorter useful lives were subdivided into Account 312 V-Z and to Account 312 L-P (if they were related to environmental compliance). Despite having a shorter useful life than other assets in Account 312, the remaining life of these environmental assets is still constrained by the remaining life of the plant as a whole because the environmental assets would be retired when the overall plant is retired.

The Wilson Plant is significantly newer than the other facilities. As such, its plant balance is significantly larger in comparison to the other facilities. If the remaining service life of each facility is weighted by the plant balances in Account 311 – Structures, Account 312 – Boiler Plant, and Account 314 – Turbine, the weighted average remaining service life is approximately 26 to 28 years. As such, the remaining service life for Account 311 – Structures was assumed to be 28 years and the remaining service life for Account 312 – Boiler Plant and Account 314 – Turbine was assumed to be 26 years.

Insufficient plant additions prior to retirement activity prevented a reliable actuarial analysis of Account 316 – Miscellaneous Equipment. As a result, other publicly available industry information, the Engineer's Assessment in Section II and the judgment of the depreciation consultant were relied upon to estimate a reasonable average service life for this account.

G. Depreciation Analysis and Methods

Q. Describe the depreciation analysis.

A. The depreciation rate analysis was performed based on the electric generation, transmission, and general plant historical accounting records of Big Rivers as of July 31, 2012. The methodologies and basis for calculating the proposed depreciation rates and completing the 2012 Depreciation Study are similar to the process utilized in completing the 2010 Depreciation Study. This depreciation rate analysis was conducted to analyze the service life characteristics, net salvage values, and depreciation reserve status based on historical data from Big Rivers' CPR system data, and then to derive appropriate depreciation rates for Big Rivers' system plant in service.

Q. Describe the key differences between the 2010 Depreciation Study and the 2012 Depreciation Study.

A. Big Rivers' 2012 Depreciation Study reflects production plant, transmission, and general plant account balances and reserve balances as of July 31, 2012. The 2010 Depreciation Study included production plant, transmission, and general plant account balances and reserve balances as of April 30, 2010. (*See* Letter from Jon Summerville and Ted J. Kelly to Billie Richert, Nov. 28, 2012, attached hereto as Exhibit Kelly-2 (comparing the preparation of the 2012 Depreciation Study and the 2010 Depreciation Study).)

The existing depreciation rates in the 2012 Depreciation Study are the same depreciation rates that were proposed and approved in the 2010 Depreciation Study. (*See* Exhibit Kelly-1, pp. ES-6, III-6 (containing tables comparing existing and proposed depreciation rates).)

The remaining service lives in the 2012 Depreciation Study reflect the passage of time between the two studies. The average service lives are the same in both studies for all accounts.

As I discuss later in this testimony, Big Rivers' management decided that due to the short period of time since the 2010 Depreciation Study was completed and approved and the expedited timeframe required for this report it would be appropriate to use net salvage factors that are consistent with the 2010 Depreciation Study. The analysis required to incorporate the 2010 and 2011 removal costs in Big Rivers proposed depreciation rates has been deferred and will be addressed in a future depreciation study.

Q. Describe the depreciation rate study methods you employed.

A. Two primary methods have been used to calculate depreciation accruals: the Whole Life method and the Life Span method combined with the Remaining Life technique. The Whole Life method was used for most General Plant accounts and the Life Span method combined with the Remaining Life technique was used for all Transmission accounts and all Production accounts and Account 390 –Structures.

Q. Describe the Whole Life depreciation method.

A. The Whole Life method uses the average service life (ASL) and the average net salvage percentage (NS) for the account to calculate the annual depreciation rate according to the following formula:

$$(1 - NS)/ASL$$

Whole life depreciation rates are appropriate for mass property types of accounts where there are a large number of relatively small property units with no definite or planned final retirement, retirements of individual units are independent of each other, and additions are generally independent of existing units. Typical property falling into this category includes tools, vehicles, computers, and furniture.

Estimates of average service life and dispersion were studied using the retirement rate method of actuarial analysis based upon the historical nature of the characteristics of the plant retired from each account since inception. For accounts where retirement activity was insufficient to conduct actuarial analysis, or when the results of such an analysis were inconclusive, other publicly available industry information and the professional judgment of the depreciation consultant were relied upon to estimate reasonable average service lives and/or average net salvage values.

Q. Describe the Life Span depreciation method.

A. The Life Span method calculates lives for an asset group or account based on the assumption that all property units in the group will retire concurrently at a single forecasted point in time, whether the units are part of the initial installation or later additions. Typical property falling into this category includes poles, transformers, conductors, power production facilities, and buildings. Forecasting reasonable retirement dates is the most critical aspect of the Life Span method.

During the life of an operational power plant and building, portions of the facility are retired and replaced. These items typically include roofs, HVAC equipment, boiler tubes and walls, pumps, and piping allocated to the cost of the facility. Because not all items remain the entire length of time a power plant or building remains in service, these so-called interim retirements tend to decrease the life of the dollars in the group or account. Therefore, it is important in a depreciation study to analyze the historical interim retirement amounts and whether the interim retirement rates are expected to continue at the same pace over the remaining life of the unit.

Interim retirements can be studied mathematically using the system of Iowa curves, the Gompertz-Makeham formula, or derived interim retirement rate curves. As the information was readily available, interim retirement life tables were developed separately for each of the accounts under the Life Span method.

Although detailed interim retirement records are maintained for each building and production facility, interim retirements for most locations are relatively few and little applicable life knowledge would be derived from attempting an analysis on such a thin available data set. Therefore, to improve the validity of the interim retirement rate analysis, an interim retirement rate calculation was performed for each account as a whole, rather than by account and then by location.

Engineers assessed the Big Rivers electric plant facilities regarding their design, performance, operation and maintenance, and condition, and provided estimates of final retirement dates for each production plant and each general plant structure to the depreciation consultants as inputs to the depreciation model. The Engineering Assessment of the major system facilities is contained in Part II of the 2012 Depreciation Study. For each production account and buildings account, an average year of final retirement (AYFR) was calculated for each major facility using the direct weighted average of individual retirement years and plant balances. This

AYFR and the aforementioned interim retirement rates are inputs to the remaining life (RL) calculation for each account.

The RL depreciation rate automatically adjusts for past under- and over-accruals by building those amounts into the depreciation rate calculation using the reserve ratio (RR). The RR is the depreciation reserve amount divided by the plant balance at the point in time of the 2012 Depreciation Study (July 31, 2012). The net salvage parameter in the RL rate equation is the future net salvage rate (FS). The RL depreciation rate is expressed mathematically as:

$$(1 - FS - RR) / RL$$

Actuarial methods are the most accurate and applicable in the determination of historic trends for assessing average service lives and salvage specific to a plant account when there is significant annual turnover of plant in that account. However, the limited activity in several accounts prevented actuarial analyses. For accounts where retirement activity was insufficient to conduct actuarial analysis, or for when the results of such an analysis were inconclusive, other publicly available industry information, the Engineering Assessment in Section II, and the engineering judgment of the depreciation consultants were relied upon to estimate reasonable average service lives. Three engineering publications that provide electric industry information were also considered as a resource for making certain assumptions or for the evaluation of lifespan and salvage value parameters:

1. "Depreciation Statistics from 100 Large United Electric Utilities – FERC Jurisdiction", Society of Depreciation Professionals Journal, Mougin, Clarence, 1992.
2. "A Survey of Depreciation Statistics", Edison Electric Institute, Robinson, Earl, 1995.
3. "Power Plant Removal Costs Revisited", Society of Depreciation Professionals Journal, Ferguson, John, 1997.

Q. How did you perform the net salvage analysis and calculate removal costs?

A. For the 2012 Depreciation Study, Big Rivers provided salvage values and removal costs for 2010 and 2011. Including the very large removal costs incurred by Big Rivers in 2010 and 2011 resulted in unrealistic net salvage factors. Therefore, the net salvage factors for each production, transmission, and general plant account were taken directly from the net salvage analysis performed in the 2010 Depreciation Study. The net salvage factors provided in the 2010 Depreciation Study are calculated as an average of the available historical data by system account from 1965 to 1998 and estimated values from 1998 to 2010. The net salvage figures used in the depreciation rate formulas in the 2010 Depreciation Study are for final net salvage, *i.e.*, the gross proceeds realized less any removal cost to raze the structures represented in the account, if any.

The removal costs incurred by Big Rivers total $6.7 million in 2010 and $1.8 million in 2011. For perspective, Big Rivers' removal costs for the entire period from 1965 to 2010 were only $6.4 million. The large removal costs incurred by Big Rivers in 2010 and 2011 were actually incurred and do not appear unreasonable given the refurbishment retirements incurred at the Wilson Plant. However, Big Rivers' management decided that due to the short period of time since the 2010 Depreciation Study was completed and approved and the expedited timeframe required for this report, it would be appropriate to use net salvage factors that are consistent with the 2010 Depreciation Study. The analysis required to incorporate the 2010 and 2011 removal costs in Big Rivers' proposed depreciation rates has been deferred and will be addressed in a future depreciation study.

Q. What effect would including the removal costs for 2010 and 2011 have had on depreciation expense?

A. Big Rivers' annual depreciation expense would have increased significantly (approximately $17.7 million).

H. Study Results

Q. What are the results of your study?

A. The proposed depreciation rates have been developed for all of Big Rivers' generation, transmission, and general plant in service assets based on historical plant accounting records provided by Big Rivers' CPR system, other published depreciation survey information, and generally accepted depreciation analysis methodologies. Based on the analysis of the information provided by Big Rivers and the results of the previously completed on-site observations of the Big Rivers generation and transmission facilities, Burns & McDonnell has formulated estimates of the remaining useful service lives for each plant account.

Table ES-1 in the 2012 Depreciation Study presents the proposed remaining life estimates and the corresponding proposed depreciation rates for each plant account balance of Big Rivers' in service production, transmission and general plant as of July 31, 2012. (*See* Exhibit Kelly-1, p. ES-6.) This table also provides a comparison calculation of Big Rivers' annual depreciation expense, calculated using the existing and proposed depreciation rates. This comparison shows that the proposed depreciation rates, if implemented by Big Rivers, would result in an estimated increase in depreciation expense of approximately $1.6 million per year (3.7 percent) based on July 31, 2012 account balances.

I. Recommendation

Q. What is your recommendation?

A. I recommend that the Kentucky Public Service Commission approve the proposed depreciation rates set forth in Table ES-1 of the 2012 Depreciation Study for prospective application by Big Rivers. (*See* Exhibit Kelly-1, p. ES-6.)

IV. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES CASE NO. 2012-00535

VERIFICATION

I, Ted J. Kelly, verify, state, and affirm that I prepared or supervised the preparation of my testimony filed with this Verification, and that testimony is true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Ted J. Kelly
Ted J. Kelly

STATE OF MISSOURI)
COUNTY OF JACKSON)

SUBSCRIBED AND SWORN TO before me by Ted J. Kelly on this the 14 day of January, 2013.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

PAULA M. ANNAN
My Commission Expires
January 19, 2015
Jackson County
Commission #11992872

Paula M Annan
Notary Public
State of Missouri
My Commission Expires 1-19-15

Exhibit Kelly-1
2012 Depreciation Study

Report on the
Comprehensive Depreciation Study

Prepared for

Big Rivers Electric Corporation
Henderson, Kentucky

Big Rivers
ELECTRIC CORPORATION

November 2012
Project Number: 70000

Burns & McDonnell
SINCE 1898

Report on the Comprehensive Depreciation Study

Prepared for the

Big Rivers Electric Corporation
Henderson, Kentucky

November 2012

Project Number 70000

Prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

Burns & McDonnell SINCE 1898

November 20, 2012

Mr. Ralph Ashworth
Director Finance
Big Rivers Electric Corporation
201 Third Street
Henderson, KY 42420

Re: 2012 Comprehensive Depreciation Study
Project Number: 70000

Dear Mr. Ashworth:

This report encompasses the 2012 Comprehensive Depreciation Study (the Study), completed by Burns & McDonnell Engineering Company (Burns & McDonnell) on behalf of Big Rivers Electric Corporation (Big Rivers), for Big Rivers' electric plant, transmission, and general plant assets as of July 31, 2012. The Study was prepared in accordance with Big Rivers' Request for Proposal (RFP) dated August 3, 2012. The Study was performed for all facilities accounted for in accordance with Rural Utilities Service (RUS) Bulletin 1767B-1, Uniform System of Accounts.

Big Rivers has committed to filing for a general review of its operations and tariffs to the Kentucky Public Service Commission (KPSC) in the first quarter of 2013. This Study was also completed as a requirement for that filing. The depreciation rates developed as part of this study must be approved by the RUS and KPSC before implementation. This Study reflects the results of Burns & McDonnell's engineering assessment and analysis of the remaining useful lives of Big Rivers' system assets and presents our proposed electric plant, transmission system, and general plant depreciation rates.

The Study presents the proposed remaining life estimates and the corresponding proposed depreciation rates for each account. This Study also provides a comparison of Big Rivers' annual depreciation expense calculated using both the existing and the proposed depreciation rates based on the plant in service as of July 31, 2012. This comparison shows the proposed depreciation rates would result in an increase in depreciation expense of approximately $1.6 million per year.

This report represents the completion of Burns & McDonnell's scope of services for the Study on behalf of Big Rivers. Our project manager and team of engineers who participated in the project would like to extend appreciation to the staff for their assistance during the project. We are available to discuss this report and Burns & McDonnell's findings with you at your convenience.

Sincerely,
Burns & McDonnell

Jon Summerville
Project Manager

Ted J. Kelly
Principal & Project Director

JES/tjk

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Tel: 816-333-9400 • Fax: 816-333-3690 • www.burnsmcd.com

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EXECUTIVE SUMMARY

EXECUTIVE SUMMARY

This report describes the 2012 Comprehensive Depreciation Study (the Study), completed by Burns & McDonnell Engineering Company (Burns & McDonnell) on behalf of Big Rivers Electric Corporation (Big Rivers; or the Cooperative), pertaining to Big Rivers' electric, transmission, and general plant assets in service as of July 31, 2012. The Study was prepared in accordance with Big Rivers' Request for Proposal (RFP) dated August 3, 2012.

INTRODUCTION

The Study desired by Big Rivers was to be performed for all facilities in accordance with Rural Utilities Service (RUS) Bulletin 1767B-1. Big Rivers and Burns & McDonnell jointly completed and filed the last depreciation study titled "Report on the Comprehensive Depreciation Study" with the RUS in February of 2011 (2010 Study). Big Rivers requires a current study be performed because Big Rivers has committed to filing a general review of its operations and tariffs with the Kentucky Public Service Commission (KPSC) in the first quarter of 2013. This Study was completed as a requirement for that filing with the KPSC.

Burns & 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. Generally, the previously completed site visits at included observation of the equipment and facilities and discussions with Big Rivers' staff and included the following activities.

- Observation of transmission and generating plant equipment and facilities
- Evaluation of equipment and facilities condition
- Interview of transmission and production operating and maintenance staff
- Review of organization structure, procedures, and staffing levels
- Determination of transmission and production operating and maintenance practices

- Assessment of transmission and production operating and maintenance experiences
- Collection of pertinent cost and operating data and records
- Collection of environmental data
- Development of facilities descriptions

The projected remaining useful lives of the various transmission assets and generating assets for each plant were then factored into the depreciation rate analysis performed by Burns & McDonnell's depreciation consultants. The Study included analysis of the service life characteristics, projected net salvage values, and depreciation reserves for the generating assets, as well as for the transmission and general plant assets.

The information used in the analysis of Big Rivers' depreciation rates was provided by the Cooperative's staff. This included various computer-generated accounting data, certain performance results, budgets, inspection reports, technical documents such as drawings and specifications, contracts, policies and procedure manuals, and other documents such as prior related studies. Historical data from 1965 to 2012 that was recorded in Big Rivers' Continuing Property Records (CPR) system was used throughout the analyses. For plant categories where sufficient experience data was not available, publicly available industry data was utilized as a representative proxy.

The previously completed site visits were conducted at each of Big Rivers' production facilities, representative transmission substations, representative transmission lines, and the headquarters offices in Henderson, Kentucky. Key production, environmental, and accounting staff were interviewed and the condition of the facilities was assessed during these site visits. The site observations of the system facilities did not include any internal inspections or examinations, environmental testing, or completion of any performance tests on the equipment and facilities. No system, structural, pipe stress, or other mathematical modeling analysis was included in the scope of the facilities observations.

Generally accepted depreciation study procedures widely used by the utility industry were followed. Actuarial analysis of average service lives and dispersions based on historical characteristics of the RUS account since inception were developed. Either the Whole Life procedure or the Life Span combined with the Remaining Life technique was used to calculate the proposed depreciation rate for each account, depending on the nature of the types of property units included in the account.

ENGINEERING ASSESSMENT

Estimated remaining useful lives for Big Rivers' generating plant assets were based, in part, on the American Society of Testing and Materials (ASTM) guidelines for high temperature creep design. Per these guidelines, the portions of a generating facility subject to creep stress should be designed to experience at least 200,000 hours of service or 5,000 thermal cycles. Assuming 8,000 hours of full-load operation per year, this equates to 25 years of service.

Because most equipment manufacturers are quite conservative in applying these guidelines, reaching these levels of service does not mean that a generating unit cannot provide reliable service for much longer periods. It does mean that creep-susceptible portions of a generating unit that has logged this level of operation should undergo metallurgical testing to detect the beginning of creep stress damage. Once damage is detected, the affected components should be evaluated regularly and repairs or replacement performed as indicated to facilitate the unit's successful return to service.

Burns & McDonnell recommends that Big Rivers continues to follow a comprehensive program of testing on those units approaching the service limits in the ASTM guidelines. Individual components should be either repaired or replaced as damage is identified. Since creep stress is a long-term phenomenon, there should be adequate time to procure and schedule replacement of any damaged components. All of the Big Rivers generating units have reached the age when this testing program should be performed. This testing is currently being performed by Big Rivers and should continue to be performed.

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. Based on the assumption that Big Rivers will be able to perform future major maintenance in a manner consistent with prudent utility operations, there is no reason, from a mechanical engineering perspective, that all of Big Rivers' generating units cannot remain in service for a long time. Should major maintenance continue to be postponed, it is not likely that all of Big Rivers' generating units will remain in service as long as similar generating units.

In the initial study conducted in 1998 an additional 200,000 hours of operation was assumed as the remaining useful life of each plant beyond the original 200,000 hours from ASTM guidelines, for a total of 400,000 hours. Based on Big Rivers' records of operation, maintenance and component replacements; other service documents; and previously completed on-site inspections; approximately 30,000 – 60,000 hours of additional operation was assumed to calculate the remaining useful life of each unit. The typical operating hours from the 2010 Study along with the actual historical operating hours the last eight years for each unit were assumed to continue for purposes of translating the remaining operating hours into remaining years of service.

DEPRECIATION RATE ANALYSIS

The Study was conducted to analyze the service life characteristics, net salvage indications, and depreciation reserve status based on historical data from Big Rivers' CPR system data, and then to derive appropriate depreciation rates for Big Rivers' electric plant in service, transmission system, and general plant assets. Actuarial analyses were performed using Big Rivers' historical data and applied to individual accounts to estimate useful service lives.

Two primary methods were used to calculate depreciation accruals: the Whole Life method (most General Plant accounts) and the Life Span method combined with the Remaining Life technique (all Production accounts, Transmission accounts, and Account 390 – Structures).

Burns & McDonnell's engineers and depreciation consultants performed analysis of available data and information in order to assess whether specific detailed estimates of terminal removal costs for each of the Big Rivers generating stations could be developed with reasonable substantiation. The significant potential costs that could be required for environmental remediation required at the Big Rivers plant sites were not considered in developing the net salvage values. Instead, the historical removal costs provided by Big Rivers from the 2010 Study were used in calculating the net salvage factors.

Table ES-1 shows each capital plant account balance and reserve balance studied as of July 31, 2012. Table ES-1 also summarizes the results of the depreciation rate analysis by showing the existing depreciation rates and annual depreciation expense compared to the proposed depreciation rates and annual depreciation expense. Detailed calculations for the proposed rates are provided in Appendix A.

Annual depreciation expense based on applying the existing depreciation rates to the July 31, 2012 balances in each account totaled $43.9 million. The application of the proposed depreciation rates to the same July 31, 2012 account balances resulted in estimated annual depreciation expense of approximately $45.5 million, representing an estimated increase in Big Rivers' total annual depreciation expense of approximately $1.6 million.

Table ES-1: 2012 Depreciation Rate Study Summary

Account	Description	As of July 31, 2012 Plant Balance - $ -	Reserve Balance - $ -	Reserve Ratio	Existing Depreciation Rate - % -	Average Service Life - Years -	Remaining Service Life - Years -	Net Salvage Factor - % -	Proposed Depreciation Rate - % -	Annual Depreciation Expense Existing - $ -	Proposed - $ -	Variance - $ -
310	Land & Land Improvements	4,537,577	0									
PRODUCTION PLANT [1]												
340	Land	475,968	0									
311	Structures	125,693,531	82,324,994	65.5	1.38%	62.0	28.2	-4.5%	1.38%	1,734,571	1,737,612	3,041
312	Boiler Plant	680,885,710	356,227,283	52.3	1.88%	59.5	26.1	-5.0%	2.02%	12,800,651	13,732,241	931,589
312 A-K	Boiler Plant - Environment Compliance	577,753,481	222,781,719	38.6	2.28%	53.0	26.1	-2.0%	2.43%	13,172,779	14,016,172	843,392
312 L-P	Short-Life Production Plant -Environmental	13,034,034	3,069,236	23.5	20.22%	10.0	4.8	0.0%	15.95%	2,635,482	2,078,941	(556,541)
312 V-Z	Short-Life Production Plant -Other	721,531	(178,280)	-24.7	14.39%	10.0	4.9	0.0%	25.38%	103,828	183,151	79,323
314	Turbine	230,546,435	129,685,979	56.3	1.91%	59.5	26.5	-8.2%	1.96%	4,403,437	4,511,020	107,583
315	Electric Equipment	62,213,068	37,265,920	59.9	1.99%	50.9	18.3	3.0%	2.03%	1,238,040	1,261,703	23,663
316	Miscellaneous Equipment	4,745,114	60,556	1.3	3.78%	57.5	24.3	0.5%	4.04%	179,365	191,836	12,471
341	CT - Structures	154,233	122,610	79.5	1.17%	52.5	19.4	0.0%	1.06%	1,805	1,633	(172)
342	CT - Fuel Holders & Access.	1,442,387	641,686	44.5	9.10%	52.5	19.2	-134.8%	9.92%	131,257	143,063	11,806
343	CT - Prime Movers	4,915,886	3,929,184	79.9	3.02%	52.5	19.4	-38.3%	3.02%	148,460	148,316	(144)
344	CT - Generators	1,102,964	1,027,096	93.1	0.50%	52.5	19.5	0.0%	0.35%	5,515	3,891	(1,624)
345	CT - Accessory Electrical Equipment	399,274	178,372	44.7	2.05%	52.5	18.9	0.0%	2.93%	8,185	11,683	3,498
	Subtotal	1,708,621,193	837,136,354							36,563,375	38,021,262	1,457,887
TRANSMISSION [1]												
350	Land	704,868	0									
352	Structures	6,872,307	3,939,593	57.3	1.90%	52.5	23.3	-2.4%	1.94%	130,574	133,325	2,752
353	Station Equipment	123,005,428	57,372,818	46.6	2.23%	52.5	23.4	-0.2%	2.29%	2,743,021	2,818,401	75,380
354	Towers	8,593,544	5,258,193	61.2	1.42%	57.5	28.5	0.0%	1.36%	122,028	117,062	(4,967)
355	Poles	42,531,008	24,872,625	58.5	2.06%	49.5	20.5	0.0%	2.03%	876,139	861,385	(14,754)
356	Lines	43,877,088	25,179,681	57.4	1.69%	52.5	23.5	0.0%	1.81%	741,523	795,634	54,112
	Subtotal	225,584,244	116,622,910							4,613,285	4,725,807	112,523
GENERAL PLANT [2]												
389	Land	407,251	0									
390	Structures [1]	5,263,520	1,841,773	35.0	2.84%	42.5	11.5	21.8%	3.76%	149,484	198,151	48,667
391.0/391.6/391.7	Office Furniture & Equipment	797,888	(226,065)	-28.3	17.12%	10.0	6.0	8.9%	9.11%	136,598	72,724	(63,875)
391.2, 391.3	Computer	20,489,975	2,105,972	10.3	10.29%	10.0	4.8	1.2%	9.88%	2,108,418	2,024,934	(83,484)
392.2	Vehicles - General	2,085,515	1,222,328	58.6	4.39%	10.0	3.0	14.2%	8.58%	91,554	179,034	87,480
392.3	Vehicles - Transmission	1,257,240	788,792	62.7	6.14%	10.0	4.7	16.9%	8.31%	77,195	104,450	27,256
393	Stores Equipment	98,766	77,948	78.9	4.40%	16.0	5.2	4.4%	5.97%	4,346	5,900	1,554
394	Tools	731,818	441,711	60.4	4.61%	16.0	8.2	2.7%	6.08%	33,737	44,482	10,745
395	Lab Equipment	221,279	176,719	79.9	4.41%	16.0	5.7	2.1%	6.12%	9,758	13,541	3,783
396	Power Operated Equipment	567,875	423,883	74.6	3.70%	16.0	5.6	24.9%	4.69%	21,011	26,644	5,632
397	Communication Equipment	1,670,551	1,488,248	89.1	4.35%	16.0	1.0	-0.1%	6.25%	72,669	104,474	31,805
398	Miscellaneous Equipment	251,254	44,367	17.7	11.80%	16.0	9.0	3.2%	6.05%	29,648	15,200	(14,448)
	Subtotal	33,842,932	8,385,678							2,734,419	2,789,533	55,115
TOTAL		$1,968,115,264	$962,144,943							$43,911,079	$45,536,603	$1,625,524

[1] Life Span Method depreciation
[2] Whole Life Method depreciation

SUMMARY & CONCLUSIONS

Based on our analysis of the information provided by Big Rivers and the results of the previously completed property observations of the Big Rivers system facilities, Burns & McDonnell has formulated estimates of the remaining useful service lives for each plant and the transmission system assets. From this, proposed depreciation rates have been developed for all of the Cooperative's generation, transmission, and general plant in service, utilizing historical accounting records data, other published depreciation survey information, and generally accepted depreciation analysis methodologies.

Assuming that the recommended equipment testing on the generating plant assets is continued, that Big Rivers will be able to perform future major maintenance in a manner consistent with prudent utility operations, and assuming that any damaged components of the equipment are either repaired or replaced, Burns & McDonnell finds that there should be no reason, from a mechanical engineering perspective, that all of Big Rivers' generating units could not remain in reliable operating service well into the future. This conclusion is conditioned by the forthcoming statement of limiting conditions.

Therefore, Burns & McDonnell recommends to Big Rivers that it consider pursuing approval and implementation of the proposed depreciation rates for each RUS account as presented in this report. These proposed depreciation rates are projected to increase the total annual depreciation expense of Big Rivers by approximately 3.7 percent.

STATEMENT OF LIMITING CONDITIONS

The analysis and results of the Study developed and presented herein by Burns & McDonnell are based on sound engineering and economic theory. However, certain factors and parameters affecting the performance of the Study must be clearly stated. The estimated remaining useful lives, net salvage rates, and proposed depreciation rates are provided subject to the following limiting conditions:

1. All existing information and facts known to Big Rivers were assumed to have been made available.

2. Assessments of the condition of the assets were based solely on casual observations. No detailed testing of any of the equipment or facilities was performed by Burns & McDonnell.
3. Generally accepted levels of and procedures for operation and maintenance of the plant in service throughout the remaining life was assumed in the future.
4. Emphasis on the engineering assessment of the generating assets and transmission assets was assumed. No physical inspection of transmission and general plant assets was made.

In the preparation of this report, the information provided to us by Big Rivers was used by Burns & McDonnell to make certain assumptions with respect to conditions that may exist in the future. While we believe the assumptions made are reasonable for the purposes of this report, we make no representation that the conditions assumed will, in fact, occur. In addition, while we have no reason to believe that the information provided to us by Big Rivers, and on which we have relied, is inaccurate in any material respect, we have not independently verified such information and cannot guarantee its accuracy or completeness. To the extent that actual future conditions differ from those assumed herein or from the information provided to us, the actual results will vary from those projected.

* * * * *

PART I - INTRODUCTION

PART I
INTRODUCTION

This report describes the Comprehensive Depreciation Study completed by Burns & McDonnell Engineering Company for Big Rivers Electric Corporation (as of July 31, 2012). The Study was prepared in accordance with Big Rivers' Request for Proposal (RFP) dated August 3, 2012. The Study desired by Big Rivers was to be performed for all facilities accounted for in accordance with RUS Bulletin 1767B-1, Uniform System of Accounts.

Part II of the Study, Engineering Assessment, is intended to address the issues identified by the RUS to be covered in the Study:

- Discussion of facility basic design and equipment
- Analysis of plant historical performance
- Review of on-site inspections and analysis of operating conditions
- Discussion of Big Rivers' operation, maintenance, and staffing
- Analysis of external and environmental factors affecting asset useful lives
- Statement of opinion regarding remaining useful lives and proper depreciation rates

Descriptions of each of Big Rivers' generating stations are provided, along with assessments of the recent historical operations and maintenance and the physical condition of each plant developed through the previously completed on-site observations of the facilities. The engineering assessment presented in Part II addresses each of the above areas, with the exception of the development of proposed depreciation rates.

The analyses leading to formulation of proposed new depreciation rates for Big Rivers are described in Part III. Part III provides brief descriptions of the alternative methods used in calculating depreciation rates and identifies the specific method used, as well as the various considerations and assumptions made, in developing the actuarial analyses for each account. Detailed calculations for all the accounts are provided in Appendix A.

Part IV of the Study summarizes the results of the Study and quantifies the estimated impact of the proposed depreciation rates on Big Rivers' annual depreciation expense accrual.

BIG RIVERS ELECTRIC CORPORATION

Big Rivers is a generation and transmission cooperative that provides bulk wholesale electric service to its member distribution cooperatives, with delivery through high voltage transmission facilities it owns and operates. Big Rivers was established as a cooperative and is operated under the authority of the RUS, an agency within the United States Department of Agriculture. Big Rivers is headquartered in Henderson, Kentucky and provides power for retail distribution to all or part of 22 counties in western Kentucky through its three member cooperatives:

- Jackson Purchase Energy Corporation, Paducah, KY
- Meade County Rural Electric Cooperative Corporation, Brandenburg, KY
- Kenergy Corp., Henderson, KY

Big Rivers owns and operates 1,444 MW of generating capacity in four power generating stations: Robert A. Reid (130 MW), Kenneth C. Coleman (443 MW), Robert D. Green (454 MW), and D.B. Wilson (417 MW). Total power capacity is 1,819 MW, including rights to Henderson Municipal Power & Light (HMP&L) Station Two and contracted capacity from Southeastern Power Administration (SEPA).

Big Rivers also owns and operates approximately 1,260 miles of transmission lines, most of which are operated at 69 kilovolts (kV), 161 kV, or 345 kV. In addition, the Cooperative's transmission system includes electric substations with over 3,540 MVa of transformer capacity. General plant facilities of Big Rivers include its headquarters office buildings, a warehouse, the central lab, publications, and communications buildings, the vehicle and power-operated equipment fleets, and all types of equipment, furniture, computers, and other items used in the Cooperative's operations.

PURPOSE OF STUDY

Big Rivers completed and filed its last depreciation study (conducted by Burns & McDonnell) with the RUS in February of 2011. Big Rivers has committed to filing a general review of its operations and tariffs with the KPSC within the first quarter of 2013. The KPSC has required that a new depreciation study be submitted as part of that filing.

Big Rivers solicited proposals and retained Burns & McDonnell to perform the Study in accordance with the RUS' guidelines. This Study includes:

- A discussion of each production facility's basic design and equipment
- A discussion of the composition of the transmission system
- An analysis of each production facility's historical performance
- Previously completed on-site reviews and analyses of each transmission system and production facility's current operating condition
- A discussion of the operating and maintenance procedures and staffing for each production facility and the transmission system
- An analysis of external and environmental factors that may impact the transmission system and each production facility's remaining useful life

PROJECT APPROACH

Burns & McDonnell's approach to meeting the above stated requirements for the Study was identical to the study completed in 2011. The Study was also based (in part) on the performance of previously completed physical site observations of the generating facilities and transmission system by experienced power plant design engineers and transmission system design engineers. These engineers then applied their experience and engineering judgment in approximating the remaining lives of each of Big Rivers' generating facilities and the transmission system. The activities performed during the previously completed site visits included:

- Observation of transmission and generating plant equipment and facilities
- Evaluation of equipment and facilities condition
- Interview of transmission and production operating and maintenance staff

- Review of organization structure, procedures, and staffing levels
- Determination of transmission and production operating and maintenance practices
- Assessment of transmission and production operating and maintenance experiences
- Collection of pertinent cost and operating data and records
- Collection of environmental data
- Development of facilities descriptions

The site observations of the plant facilities and transmission system did not include any internal inspections or examinations, or completion of any performance tests on the equipment and facilities. No system, structural, pipe stress, or other mathematical modeling analysis was included in the scope of the facilities observations.

The significant potential costs that could be required for environmental remediation were not considered in developing the net salvage values. Instead, the historical removal costs provided by Big Rivers in the 2010 Study were used in calculating the net salvage factors.

The projected remaining useful lives of the various generating and transmission assets and the estimates of terminal net salvage values were then factored into the depreciation rate analysis performed by Burns & McDonnell's depreciation consultants. The Study included analysis of the service life characteristics, net salvage values, and depreciation reserves for the generating assets, transmission assets, and general plant assets. Raw historical plant account data from 1965 to 2012 was obtained from Big Rivers' CPR system.

Generally accepted depreciation study procedures and actuarial analyses widely used by the utility industry were followed. Actuarial analyses of average service lives and dispersions based on historical characteristics of the plant retired for each active RUS plant account since inception were developed. Either the Whole Life method or the Life Span method with the Remaining Life technique was used to calculate the proposed depreciation rate for each account, depending on the nature of the types of property units included in an account.

SOURCES OF DATA

Much of the information used in the analysis of Big Rivers' depreciation rates was provided by the Cooperative's staff. This included various computer-generated accounting data from Big Rivers' CPR system, certain performance results, budgets, inspection reports, technical documents such as drawings and specifications, contracts, policies and procedure manuals, and other documents such as prior related studies. Historical data from 1965 to 2012 as recorded in Big Rivers' CPR system was used throughout the analyses.

Previously completed site visits were conducted at each of Big Rivers' electric generating facilities, system transmission substations, representative transmission lines, and the headquarters offices in Henderson, Kentucky. Key production, engineering, and accounting staff were interviewed and the condition of the facilities was discussed and assessed during these site visits. The site observations of the system facilities did not include any internal inspections or examinations, environmental testing, or completion of any performance tests on the equipment and facilities. No system, structural, pipe stress, environmental assessment, or other mathematical modeling analysis was included in the scope of the facilities observations.

* * * * *

PART II – ENGINEERING ASSESSMENT

PART II

ENGINEERING ASSESSMENT

OVERVIEW

This section of the report provides an engineering assessment of the Big Rivers' generation and transmission plant assets. In completing the assessment Burns & McDonnell interviewed appropriate Big Rivers staff concerning the operation and maintenance of the system assets. The following activities were conducted to examine Big Rivers' generation and transmission plant assets from an engineering perspective.

- A discussion of each production facility's basic design and equipment
- Previously completed on-site reviews and analyses of each production facility's current operating condition
- An analysis of each production facility's historical performance
- A discussion of the operating and maintenance procedures for each production facility
- An analysis of external factors that may impact each facility's useful life
- An opinion, based on the study's findings, regarding the remaining life of each facility
- A discussion of the composition of the transmission system
- An opinion, based on the study's findings, regarding the remaining life of each substation

The engineering assessment presented in this section addresses each of the above areas. The analyses leading to formulation of proposed new depreciation rates for Big Rivers are described in Part III.

Generation Facilities

Table II-1 below provides a description of each unit of Big Rivers' fleet of generating facilities, including the commercial operation date, years in operation, net capacity, heat rate, fuel type, boiler and turbine manufacturer, and emission control equipment.

Table II-1: Big Rivers Power Plant Data

Unit	Commercial Operation Date	Years in Operation	Net Capacity (MW)	2011 Heat Rate (Btu/kWh)	Fuel Type	Boiler Manufacturer	Turbine Manufacturer	Emission Control Equipment: SO_2 Control	Emission Control Equipment: NO_X Control	Emission Control Equipment: Particulate Control
Coleman 1	1969	43	150 MW	10,656	Pulverized Coal	Foster Wheeler	Westinghouse	FGD	Low NO_X Burners/ Overfire Air	Precipitator
Coleman 2	1970	42	138 MW	11,537	Pulverized Coal	Foster Wheeler	Westinghouse	FGD	Low NO_X Burners/ Overfire Air	Precipitator
Coleman 3	1972	40	155 MW	10,609	Pulverized Coal	Riley Stoker	General Electric	FGD	Low NO_X Burners/ Overfire Air	Precipitator
Green 1	1979	33	231 MW	11,270	Pulverized Coal	Babcock & Wilcox	General Electric	FGD	Low NO_X Burners	Precipitator
Green 2	1981	31	223 MW	11,193	Pulverized Coal	Babcock & Wilcox	Westinghouse	FGD	Low NO_X Burners	Precipitator
HMP&L 1	1973	39	153 MW	11,035	Pulverized Coal	Riley Stoker	General Electric	FGD	SCR	Precipitator
HMP&L 2	1974	38	159 MW	11,286	Pulverized Coal	Riley Stoker	Westinghouse	FGD	SCR	Precipitator
Reid 1	1966	46	65 MW	15,027	Pulverized Coal Natural Gas	Riley Stoker	General Electric	Uses Medium Sulfer Coal	Burns Natural Gas to Reduce Nox	Precipitator
Reid CT	1976	36	65 MW	11,750	#2 Oil Natural Gas	na	General Electric	na	na	na
Wilson 1	1986	26	417 MW	10,752	Pulverized Coal	Foster Wheeler	Westinghouse	FGD	SCR	Precipitator

Remaining Useful Life

Estimated remaining useful lives for Big Rivers' generating plant assets were based, in part, on ASTM guidelines for high temperature creep design. Per these guidelines, the portions of a generating facility subject to creep stress should be designed to experience at least 200,000 hours of service or 5,000 thermal cycles. Assuming 8,000 hours of full-load operation per year, this equates to 25 years of service.

Because most equipment manufacturers are quite conservative in applying these guidelines, reaching these levels of service does not mean that a generating unit cannot provide reliable service for longer periods. It does mean that creep-susceptible portions of a generating unit that has logged this level of operation should undergo metallurgical testing to detect the beginning of creep stress damage. Once damage is detected, the affected components should be evaluated regularly and repairs or replacement performed as indicated to facilitate the unit's successful return to service.

Burns & McDonnell recommends that Big Rivers continue to follow a comprehensive program of testing on those units approaching the service limits in the ASTM guidelines. Individual components should be either repaired or replaced as damage is identified. Since creep stress is a long-term phenomenon, there should be adequate time to procure and schedule replacement of any damaged components.

All of the Big Rivers generating units have reached the age when this testing program should be (and is) performed. This testing is currently being performed by Big Rivers and there is no reason, from a mechanical engineering perspective, that all of Big Rivers' generating units cannot remain in service for a long time. The following table provides a summary of the most recent testing performed for each generation unit.

Table II-2: Big Rivers Recent Generation Testing Results

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.	

In the 1998 depreciation study an additional 200,000 hours of operation was assumed as the remaining useful life of each plant beyond the original 200,000 hours taken from ASTM guidelines, for a total of 400,000 hours. Based on Big Rivers' records of operation, maintenance and component replacements; other service documents; and previously completed on-site inspections; five to seven and a half years of additional operation was assumed to calculate the remaining useful life of each unit. The additional five to seven and a half years translates into an additional 30,000 – 60,000 hours of operation for each unit.

The typical operating hours used in the 2010 Study along with the actual operating hours the last eight years for each unit were assumed to continue for purposes of translating the remaining operating hours into remaining years of service. The remaining operating hours are based off Big Rivers' estimate of new depreciation rates going into effect August 31, 2013.

Table II-3 below shows the estimated remaining useful life for each facility assuming **typical operating hours** with an additional **seven and a half years** of operation.

Table II-3: Big Rivers Power Plant Estimated Remaining Lives: Scenario 1

Plant Name	Date in Service	Typical Lifetime Availability	Typical Operating Hours per Year	Plant Years in Service	Total Estimated Hours to Date (8/31/2013)	Calculated 7.5 Year Extension Typical Estimated Remaining Unit Life	Estimated Service Life	7.5 Year Extension Typical Estimated Remaining Unit Life	Estimated Service Life
Coleman 1	November-69	80%	7,008	43.8	307,104	20.8	64.6	20.8	64.6
Coleman 2	September-70	80%	7,008	43.0	301,267	21.6	64.6	20.8	64.6
Coleman 3	January-72	80%	7,008	41.7	291,917	22.9	64.6	20.8	64.6
Green 1	December-79	85%	7,446	33.7	251,185	27.5	61.2	27.5	61.2
Green 2	January-81	85%	7,446	32.6	243,086	28.6	61.2	27.5	61.2
HMP&L 1	June-73	85%	7,446	40.2	299,615	21.0	61.2	21.0	61.2
HMP&L 2	April-74	85%	7,446	39.4	293,413	21.8	61.2	21.0	61.2
Reid	January-66	70%	6,132	47.7	292,236	25.1	72.7	12.3	60.0
Wilson	November-86	90%	7,840	26.8	210,203	31.7	58.5	31.7	58.5

Table II-4 below shows the estimated remaining useful life for each facility assuming **typical operating hours** with an additional **five years** of operation.

Table II-4: Big Rivers Power Plant Estimated Remaining Lives: Scenario 2

Plant Name	Date in Service	Typical Lifetime Availability	Typical Operating Hours per Year	Plant Years in Service	Total Estimated Hours to Date (8/31/2013)	Calculated 5 Year Extension Typical Estimated Remaining Unit Life	Estimated Service Life	5 Year Extension Typical Estimated Remaining Unit Life	Estimated Service Life
Coleman 1	November-69	80%	7,008	43.8	307,104	18.3	62.1	18.3	62.1
Coleman 2	September-70	80%	7,008	43.0	301,267	19.1	62.1	18.3	62.1
Coleman 3	January-72	80%	7,008	41.7	291,917	20.4	62.1	18.3	62.1
Green 1	December-79	85%	7,446	33.7	251,185	25.0	58.7	25.0	58.7
Green 2	January-81	85%	7,446	32.6	243,086	26.1	58.7	25.0	58.7
HMP&L 1	June-73	85%	7,446	40.2	299,615	18.5	58.7	18.5	58.7
HMP&L 2	April-74	85%	7,446	39.4	293,413	19.3	58.7	18.5	58.7
Reid	January-66	70%	6,132	47.7	292,236	22.6	70.2	12.3	60.0
Wilson	November-86	90%	7,840	26.8	210,203	29.2	56.0	29.2	56.0

Table II-5 below shows the estimated remaining useful life for each facility assuming **actual operating hours** with an additional **seven and a half years** of operation.

Table II-5: Big Rivers Power Plant Estimated Remaining Lives: Scenario 3

Plant Name	Date in Service	Actual Operating Hrs Based on 8 Yr Avg	Plant Years in Service	Total Estimated Hours to Date (8/31/2013)	Calculated 7.5 Year Extension Estimated Remaining Unit Life	Estimated Service Life	7.5 Year Extension Estimated Remaining Unit Life	Estimated Service Life
Coleman 1	November-69	7,825	43.8	342,895	14.8	58.6	13.8	56.8
Coleman 2	September-70	8,114	43.0	348,810	13.8	56.8	13.8	56.8
Coleman 3	January-72	8,069	41.7	336,116	15.4	57.1	13.8	56.8
Green 1	December-79	8,146	33.7	274,792	22.9	56.6	22.9	56.6
Green 2	January-81	8,014	32.6	261,617	24.8	57.4	22.9	56.6
HMP&L 1	June-73	7,546	40.2	303,656	20.3	60.5	18.6	58.0
HMP&L 2	April-74	7,914	39.4	311,855	18.6	58.0	18.6	58.0
Reid	January-66	3,059	47.7	145,772	90.6	138.3	12.3	60.0
Wilson	November-86	7,878	26.8	211,211	31.5	58.3	31.5	58.3

Table II-6 below shows the estimated remaining useful life for each facility assuming **actual operating hours** with an additional **five years** of operation.

Table II-6: Big Rivers Power Plant Estimated Remaining Lives: Scenario 4

Plant Name	Date in Service	Actual Operating Hrs Based on 8 Yr Avg	Plant Years in Service	Total Estimated Hours to Date (8/31/2013)	Calculated 5 Year Extension Estimated Remaining Unit Life	Estimated Service Life	5 Year Extension Estimated Remaining Unit Life	Estimated Service Life
Coleman 1	November-69	7,825	43.8	342,895	12.3	56.1	11.3	54.3
Coleman 2	September-70	8,114	43.0	348,810	11.3	54.3	11.3	54.3
Coleman 3	January-72	8,069	41.7	336,116	12.9	54.6	11.3	54.3
Green 1	December-79	8,146	33.7	274,792	20.4	54.1	20.4	54.1
Green 2	January-81	8,014	32.6	261,617	22.3	54.9	20.4	54.1
HMP&L 1	June-73	7,546	40.2	303,656	17.8	58.0	16.1	55.5
HMP&L 2	April-74	7,914	39.4	311,855	16.1	55.5	16.1	55.5
Reid	January-66	3,059	47.7	145,772	88.1	135.8	12.3	60.0
Wilson	November-86	7,878	26.8	211,211	29.0	55.8	29.0	55.8

Table II-7 below shows the estimated remaining useful life for each facility assuming **typical operating hours** with an additional **seven and a half years** of operation and an assumed **65 year life for Wilson**. This table is included at the direction of Big Rivers' management in order to be consistent with the 2010 Study. It is not the opinion of Burns & McDonnell that an assumed 65 year life for Wilson is reasonable to consider. Based on its operation and other recent coal plant retirements throughout the country a useful life of 50 to 60 years is more reasonable.

Table II-7: Big Rivers Power Plant Estimated Remaining Lives: Scenario 5

Plant Name	Date in Service	Typical Lifetime Availability	Typical Operating Hours per Year	Plant Years in Service	Total Estimated Hours to Date (8/31/2013)	Calculated 7.5 Year Extension Remaining Unit Life	Estimated Service Life	7.5 Year Extension Typical Estimated Remaining Unit Life	Estimated Service Life
Coleman 1	November 15, 1969	80%	7,008	43.8	307,104	20.8	64.6	20.8	64.6
Coleman 2	September 15, 1970	80%	7,008	43.0	301,267	21.6	64.6	20.8	64.6
Coleman 3	January 15, 1972	80%	7,008	41.7	291,917	22.9	64.6	20.8	64.6
Green 1	December 15, 1979	85%	7,446	33.7	251,185	27.5	61.2	27.5	61.2
Green 2	January 15, 1981	85%	7,446	32.6	243,086	28.6	61.2	27.5	61.2
HMP&L 1	June 15, 1973	85%	7,446	40.2	299,615	21.0	61.2	21.0	61.2
HMP&L 2	April 15, 1974	85%	7,446	39.4	293,413	21.8	61.2	21.0	61.2
Reid	January 15, 1966	70%	6,132	47.7	292,236	25.1	72.7	12.3	60.0
Wilson	November 15, 1986	90%	7,840	26.8	210,203	31.7	58.5	38.2	65.0

Table II-8 below shows the estimated remaining useful life for each facility assuming **historical operating hours** with an additional **seven and a half years** of operation and an assumed **65 year life for Wilson**. This table is included at the direction of Big Rivers' management in order to be consistent with the 2010 Study. It is not the opinion of Burns & McDonnell that an assumed 65 year life for Wilson is reasonable to consider. Based on its operation and other recent coal plant retirements throughout the country a useful life of 50 to 60 years is more reasonable.

Table II-8: Big Rivers Power Plant Estimated Remaining Lives: Scenario 6

Plant Name	Date in Service	Actual Operating Hrs Based on 8 Yr Avg	Plant Years in Service	Total Estimated Hours to Date (8/31/2013)	Calculated 7.5 Year Extension Estimated Remaining Unit Life	Estimated Service Life	7.5 Year Extension Estimated Remaining Unit	Estimated Service Life
Coleman 1	November 15, 1969	7,825	43.8	342,895	14.8	58.6	13.8	56.8
Coleman 2	September 15, 1970	8,114	43.0	348,810	13.8	56.8	13.8	56.8
Coleman 3	January 15, 1972	8,069	41.7	336,116	15.4	57.1	13.8	56.8
Green 1	December 15, 1979	8,146	33.7	274,792	22.9	56.6	22.9	56.6
Green 2	January 15, 1981	8,014	32.6	261,617	24.8	57.4	22.9	56.6
HMP&L 1	June 15, 1973	7,546	40.2	303,656	20.3	60.5	18.6	58.0
HMP&L 2	April 15, 1974	7,914	39.4	311,855	18.6	58.0	18.6	58.0
Reid	January 15, 1966	3,059	47.7	145,772	90.6	138.3	12.3	60.0
Wilson	November 15, 1986	7,878	26.8	211,211	31.5	58.3	38.2	65.0

The life of these individual units can vary based on a number of factors, however, two major factors are operating hours and maintenance experience. The Green, HMP&L Station Two and Coleman facilities have multiple units, but are forecasted to retire in the same year. This is reasonable for three reasons. First, the units were installed within two to three years of each other. Second, most plant accounts are assigned to the entire generating station, not to individual units of the facility. Most importantly, it is realistic to assume that the entire facility would shut down before significant demolition activities begin to occur. Piecemeal removal at an operating facility would be costly and much of the plant infrastructure would need to remain in service in order to maintain the last unit's ability to function. Big Rivers would maintain and continue to operate each individual unit until such time as the decision was made to retire the entire generating station. The Reid facility is not run nearly as much as the other facilities so its estimated service life could be limited by its ability to find spare parts in the future, not the hours of operation. Burns & McDonnell further considered the results of the previously completed on-site assessments of each of the Big Rivers generating stations in the estimation of the remaining useful lives.

Since the Unwind Closing in 2009, Big Rivers has been unable to perform major maintenance such as valve inspections and turbine generator inspections on a schedule consistent with prudent utility operations. Based on the assumption that Big Rivers will be able to perform future major maintenance in a manner consistent with prudent utility operations, there is no reason, from a mechanical engineering perspective, that all of Big Rivers' generating units cannot remain in service for a long time. Should major maintenance continue to be postponed, it is not likely that all of Big Rivers' generating units will remain in service as long as similar generating units.

GENERATION ASSETS

SEBREE SITE

The Sebree site is common to three plants owned and/or operated by Big Rivers: the Robert A. Reid Plant, the Robert D. Green Plant, and the Henderson Municipal Power & Light (HMP&L) Station Two. Although the plants are located on a common site, HMP&L Station Two is actually owned by the City of Henderson, Kentucky. Big Rivers operates HMP&L Station Two for the City. Contractual operations agreements between Big Rivers and the City of Henderson require that Big Rivers maintains separate plant operations, including operating and maintenance staffs (management staff and some specialists are common) and financial budgets/records, for the HMP&L Station Two and Reid stations, from the operations of the Green station.

The Sebree site is generally adequate for the operation of the three plants; however, the configuration of the units necessitates substantial coordination of activities among the plant staff when large areas of common space are required. This has not appeared to be a severe handicap to the site. This sharing of common facilities has produced a degree of operational and capital investment savings. For example, the river water intake structure for the Reid steam turbine unit is also used to provide river water supplies to the Green and HMP&L Station Two stations. Another example of this sharing of facilities relates to the barge unloading system used at the Reid station. When the original unloader was replaced with a more conventional barge unloader, the new unloading system and coal handling served both Reid and HMP&L Station Two. Also, when the new flue gas desulfurization system was added to the HMP&L Station Two units the lime supply and sludge disposal systems of the Green units were used. There is also some coordination among the three generating plants in ash storage; however, this is limited by the difference in the nature of the ash handling requirements for the different types of units.

The Sebree site is located on the banks of the Green River. The main plant area is located at a sufficient elevation such that 100-year floods should not affect the units' generation capabilities. Although a flood in excess of 100-year levels potentially could cause temporary interruptions of generating capability, no significant operational impact is anticipated.

ROBERT D. GREEN PLANT

Facility Description

The Robert D. Green Plant is located on the Sebree site near Sebree, Kentucky, along with the Robert A. Reid Plant and HMP&L Station Two. The Green Plant includes two units that are significantly larger than the units at either the Reid Plant or the HMP&L Station Two. Green Unit 1 is rated for net continuous capacity of 231 MW and Green Unit 2 has a rated net capacity of 223 MW. Unit 1 began commercial operation in 1979 and Unit 2 became operational in 1981. Both units at the Green Plant are coal-fired steam generating units with Babcock & Wilcox boilers providing maximum steam capacity of 1,930,000 pounds per hour. Green 1 is equipped with a General Electric turbine-generator with a nameplate rating of 242,105 kW. Green 2 includes a Westinghouse turbine-generator rated at 242,133 kW.

Steam Turbines

Green 1 turbine generator was supplied by General Electric, while the Green 2 turbine generator was supplied by Westinghouse. Both turbines appear to be in good condition. Turbine 1 underwent a major turbine overhaul in 2007. The unit is on a regular turbine outage schedule of every four years for valves and every eight years for major turbine overhaul. Turbine 2 was last overhauled in 2009, with a generator retaining ring replacement included in the overhaul. The unit is on a regular turbine outage schedule of every four years for valves and every eight years for major turbine overhaul. All evidence and inspections indicate that both turbines are being well maintained.

Boilers

The two Babcock & Wilcox boilers were installed after the initial effects of the regulations limiting NO_X emissions from coal-fired power plant boilers were promulgated. As such, the boilers are equipped with B&W's dual register burners and multiple wind boxes.
Boiler 1 appears to be in excellent condition. The tubes in the secondary superheater were replaced in 2001. Weld overlays were installed on the East and West walls, and reheat tubes were replaced in 2007. Sootblower lanes are shielded and shields are replaced as deficiencies are found. Several steam line hangers had deteriorated and were replaced in 2011. Tube samples of the waterwalls, superheat, and reheat collected in 2011 showed no significant deficiencies. However, based on the internal deposit thickness on the tube samples a water side chemical cleaning is scheduled for 2014.

Boiler 2 appears to be in excellent condition. The tubes in the secondary superheater were replaced in 2001. Weld overlays were installed on the East and West walls in 2005 and 2009. Tubes in the reheat outlet bank were replaced in 2009. Sootblower lanes are shielded and shields are replaced as deficiencies are found. Several steam line hangers had deteriorated and were replaced in 2009. Tube samples of the waterwalls, superheat, and reheat collected in 2009 showed no significant deficiencies.

Draft System

The two Green units were constructed with high efficiency precipitators and wet lime scrubbers. The precipitators appear to be in good condition and currently remove enough particulate to comply with the limit of 0.1 pounds per million Btu. Two precipitator fields were replaced in 2007 and two more in 2009. The FGD scrubbers appear to be in good condition and remove enough SO_2 to comply with the limit of 0.8 pounds per million Btu. The boilers were purchased with the earlier series of low NO_X burners from Babcock & Wilcox Company. Both units were retrofit in 2004 with a coal reburn technology designed by GE-EER. The combination reduces the NO_X emissions below the limit of 0.7 pounds per million Btu. The Ljungstrom air preheaters have had cold end baskets replaced in both units and are currently in good operating condition.

Waste Disposal

The primary water discharge is from the cooling tower blowdown. The blowdown from the cooling towers and other plant drains discharge to the main plant discharge. The waste water is pH adjusted and metals are precipitated. Discharge from these ponds is sent to a plant common pond, which then discharges indirectly to the Green River. Due to the multiple-pond system, accidental discharges reaching the river are considered unlikely. Bottom ash is impounded in the pond. The Green plant's fly ash is used for flue gas desulfurization waste sludge fixation.

Water Supply Systems

The makeup water supply from the Green River to the plant is provided from the intake structure which was originally constructed as part of the circulating water system for Reid Unit 1. Separate water supply pumps serve the Green units. Of all the water requirements of the Green units, the largest user is makeup supply for the cooling towers. Regardless of its end use, all this water is run through a conventional water clarification and treatment facility. The Green station maintains its own chemistry lab and personnel, using common supervision with the HMP&L Station Two units. Plant management provided no indications that plant chemistry control was inadequate.

Fuel Supply and Handling

The primary fuel supply for the Green units has been from nearby Kentucky mines and is delivered by truck and/or barge. The fuel supply for the Green units is delivered separately from the other coal-fired units on the site, and is kept segregated throughout the storage and handling process. This is due to the differing fuel quality requirements as well as contractual issues between Big Rivers and the City of Henderson. There is adequate space on the plant site for fuel storage for the Green units of up to 60 days. The normal fuel inventory is substantially less than the site capacity. A barge unloading facility located on the Green River (separate from the HMP&L Station Two barge unloader) is capable of unloading and delivering coal to the Green units. Lime for use in the scrubbers is delivered by barge. The barge unloader conveyor system is set up to permit transfers of materials from the Green barge unloader to either the coal pile or the lime storage silos. Plant management provided no indication of fuel supply or handling issues during the site visit.

Historical Operating Performance

Burns & McDonnell reviewed the plant's historical operating performance to verify that the generating units have competitive heat rates and are capable of providing the level of reliability to meet Big Rivers' electric production requirements. A summary of operating data is provided below in Table II-9.

Table II-9: Robert D. Green Historical Operating Performance Data

		Green Unit 1	Green Unit 2
Gross Generation Capacity	(MW)	250 MW	242 MW
Net Generation Capacity	(MW)	231 MW	223 MW
8 Year Average Capacity Factor	(%)	93.0%	91.5%
2011 Adjusted Net Heat Rate	(Btu/kWh)	11,270	11,193
7 Year Average EFOR	(%)	2.1%	1.5%

Both Green units have been performing well. The 2011 adjusted net heat rate was 11,270 Btu per kWh and 11,193 Btu per kWh for units one and two, respectively, which is competitive with other coal fired power plants in the region. The availability of the units has also been very good. Green Unit 1 has a seven year average Expected Forced Outage Rate (EFOR) of 2.1 percent while Green Unit 2 has a seven year average EFOR of 1.5 percent.

Remaining Useful Life

The Green Unit 1 and Unit 2 are in excellent condition for their age and service requirements. Provided that Big Rivers will be able to perform future major maintenance in a manner consistent with prudent utility operations, there is no reason, from a mechanical engineering perspective, that this facility cannot remain in service another 20 to 27 years (depending on its operation).

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 the units. The spreadsheet does indicate that a HEP and hanger review occurs on all the units.

HENDERSON MUNICIPAL POWER & LIGHT STATION TWO

Facility Description

HMP&L Station Two is also located on the plant site near Sebree, Kentucky, along with the Robert A. Reid Plant and the Robert D. Green Plant. HMP&L Station Two is owned by the City of Henderson, Kentucky through its municipal utility, Henderson Municipal Power & Light (HMP&L). Big Rivers operates HMP&L Station Two on behalf of the City. HMP&L Station Two includes two units similar in size to the three units at the Coleman Plant. HMP&L Unit 1 is rated for net continuous capacity of 153 MW and HMP&L Unit 2 has a rated net capacity of 159 MW. Unit 1 began commercial operations in 1973 and Unit 2 began commercial operations 1974. Both HMP&L Station Two units are coal-fired steam generating units with Riley boilers having steam flow capacity of 1,180,000 pounds per hour. Unit 1 is equipped with a General Electric turbine-generator with nameplate rating for the turbine of 175,984 kW. Unit 2 includes a Westinghouse turbine-generator rated at 178,724 kW.

Steam Turbines

HPM&L Unit 1 is equipped with a General Electric turbine-generator, and HMP&L Unit 2 is equipped with a Westinghouse turbine-generator. Both units appear to be in good condition. Turbine 1 was last overhauled in 2008, and Turbine 2 was last overhauled in 2004. Both units are on a regular outage schedule of every 4 years for valves and every 8 years for major overhauls.

Boilers

The two boilers of the HMP&L Station Two appear to be well maintained. A program of monitoring boiler tube failures and tube wear has been activated. This has resulted in replacement of some sections of the reheaters, and similar monitoring and replacement programs should result in minimizing forced outages due to boiler tube failure.

Boiler 1 appears to be in good condition. The radiant superheat inlet and outlet elements were replaced in 2003. The front waterwall release header was replaced in 2005. A low water event occurred in 2007 causing some tubes to rupture and others to warp. The ruptured tubes were replaced with dutchmen and samples were removed for metallurgical analysis. No damage was detected. The boiler was hydro tested and returned to service. Tube samples were taken from the waterwalls, superheater, and reheat in 2012. No degradation was found in the waterwall and based on the internal deposit thickness on the tube samples a water side chemical cleaning is scheduled for 2016. However, the radiant superheater outlet was suffering from severe coal ash corrosion so Big Rivers replaced the burners in 2012 to reduce the fuel velocity and help mitigate the radiant superheater corrosion. These tubes are scheduled to be replaced in 2018. The high temperature reheater was replaced during the 2009 outage. Hangers are being replaced as inspections dictate.

Boiler 2 appears to be in good condition. The radiant superheater inlet and outlet elements were replaced in 2007. The high temperature reheater elements were replaced in 2007. Tube samples were taken in 2012 show the tubes to be in good condition. No significant deficiencies were found. Feedwater corrosion products were almost at the criterion for chemical cleaning.

However, based on the internal deposit thickness on the tube samples water side chemical cleaning is scheduled for 2019. Hangers are also being replaced based on the prioritization list.

Draft System

Precipitators are currently used for particulate emission removal with a limit of 0.21 pounds per MMBtu. The units both have an FGD system in service which is able to achieve a 95 percent SO_3 removal rate. This allows the Plant to meet the SO_2 limit of 5.2 pounds per MMBTu. Both units were retrofit in 2004 with Alstom designed SCR's capable of 90 percent NO_X removal which allow the plant to meet the NO_X limit of 0.5 pounds per MMBtu.

Waste Disposal

All the plant water discharges go through the ash pond. This includes neutralized demineralizer wastes, boiler blowdown, cooling tower blowdown, and miscellaneous plant drains. The ash ponds indirectly discharge to the Green River. Water discharges are monitored in the final pond, and water quality is reported to the state. Due to the multiple pond system, accidental discharges reaching the river are considered unlikely.

Water Supply Systems

The makeup water supply to the HMP&L Station Two units is from the circulating water system of Reid 1. This system, with operating and standby pumps at the river, is capable of delivering far more water than is normally needed by the two HMP&L Station Two units. The river intake was constructed in the 1960s, and is grandfathered for any Corps of Engineers river discharge permits. River water is delivered untreated to the cooling towers, which are equipped with side stream filters. Renovation of the cooling tower water chemistry control system and side stream filters to the circulating water system has apparently been successful.

Fuel Supply and Handling

The primary fuel supply for the HMP&L Station Two units has been from Kentucky mines and is delivered by truck and by barge. The fuel purchasing is in proportion to the utilization of the units. Big Rivers secures enough fuel to produce the unit capacity controlled by the cooperative. The City of Henderson procures enough fuel to produce their portion of the HMP&L Station Two capacity which varies as load growth occurs in Henderson. Once the fuel is received on site, it is delivered either directly to the unit or to the HMP&L Station Two common storage. The coal for the Reid unit is purchased separately, and segregated in storage and use since the HMP&L Station Two units are capable of utilizing higher sulfur, less expensive coal, than the non-scrubbed Reid unit. Fuel for the Green Plant units is handled completely separately, since it is of a different quality. Maintenance of the coal handling systems appears to be adequate.

Historical Operating Performance

Burns & McDonnell reviewed the plant's historical operating performance to verify that the generating units have competitive heat rates and are capable of providing the level of reliability necessary to meet Big Rivers' electric production requirements. A summary of operating data is provided below in Table II-10.

Table II-10: HMP&L Station Two Historical Operating Performance Data

		HMP&L Unit 1	HMP&L Unit 2
Gross Generation Capacity	(MW)	165 MW	172 MW
Net Generation Capacity	(MW)	153 MW	159 MW
8 Year Average Capacity Factor	(%)	86.1%	90.3%
2011 Adjusted Net Heat Rate	(Btu/kWh)	11,035	11,286
7 Year Average EFOR	(%)	7.7%	5.1%

Both units have been performing well. The 2011 adjusted net heat rate was 11,035 Btu per kWh and 11,286 Btu per kWh for units one and two, respectively, which is competitive with other coal fired power plants in the region. Unit 1 has a seven year EFOR of 7.7 percent while Unit 2 has a seven year average EFOR of only 5.1 percent.

Remaining Useful Life

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 and hangers. A consistent program like this for monitoring status and identifying areas to address in future budgets is consistent with sound maintenance practices. The HEP and hanger review addresses the concern over creep damage with an aging plant. This review program is critical and is currently being performed on all the units. The spreadsheet does indicate that a HEP and hanger review occurs on all the units.

The HMP&L Units are in excellent condition for their age and service requirements. Provided that Big Rivers will be able to perform future major maintenance in a manner consistent with prudent utility operations, there is no reason, from a mechanical engineering perspective, that this facility cannot remain in service another 16 to 21 years (depending on its operation).

ROBERT A. REID PLANT

Facility Description

The Reid steam turbine generating unit includes a Riley boiler with a steam flow capacity of 690,000 pounds per hour and a General Electric turbine-generator with nameplate capacities of 66,000 kilowatts (kW) for the turbine and 96,000 kVA for the generator. The unit began commercial operation in 1966 and is currently rated at 65 MW.

Steam Turbine

Reid is equipped with a General Electric turbine-generator. The steam turbine was last overhauled in 2000 and does not have another major overhaul scheduled until 2018. The unit has historically been on a regular outage schedule of every four years for valves and every twelve years for major overhauls; however due to its low capacity factor (CF) it is able to run longer without a major overhaul.

Boilers

Reid 1 has a Riley Stoker boiler with two levels of burners on the front wall. The unit has had the lower waterwall tube header stubs replaced in 2004 with no major upgrades since. The boiler appears to be in good operating condition. The boiler is a pressurized furnace, with no induced draft fan.

Draft System

Precipitators are currently used for particulate emission removal with a limit of 0.28 pounds per MMBtu. The unit uses medium sulfur coal in order to meet the SO_2 limit of 5.2 pounds per MMBTU. In 2000, four of the boiler's eight burners were converted to burn natural gas to reduce NO_X emissions.

Waste Disposal

The fly ash of the Reid unit is used in the Green Plant's flue gas desulfurization waste sludge fixation. The bottom ash from the unit is impounded in the ponds.

Water Supply Systems

Circulating water for the Reid unit comes directly from, and returns to, the Green River. This direct river cooling was established before introducing changes to river water temperature was regarded as environmentally degrading and, therefore, the Reid unit is a grandfathered installation. The two 100-percent circulating water pumps are adequate for the Reid unit; however, one of these pumps is run almost continuously since the Reid unit circulating water system also provides the water supplies for HMP&L Station Two. The water supply pumps for the Green units are also installed in the Reid intake structure. The significance of this water supply system is far greater than that of the Reid unit alone, since a loss of the intake structure could shut down both HMP&L Station Two units and both Green units, a total of over 700 MW of generating capacity. However, proper maintenance reduces the probability of this occurrence to a minimum level of concern.

Historical Operating Performance

Burns & McDonnell reviewed the plant's historical operating performance to verify that the generating units have competitive heat rates and are capable of providing the level of reliability necessary to meet Big Rivers' electric production requirements. A summary of operating data is provided below in Table II-11.

Table II-11: Robert A. Reid Historical Operating Performance Data

		Reid Unit 1
Gross Generation Capacity	(MW)	72 MW
Net Generation Capacity	(MW)	65 MW
8 Year Average Capacity Factor	(%)	34.9%
2011 Adjusted Net Heat Rate	(Btu/kWh)	15,027
7 Year Average EFOR	(%)	21.2%

The plant has performed commendably over the years. However, the unit had one of the highest heat rates on Big Rivers' system. The 2011 adjusted net heat rate for the unit was reported to be 15,027 Btu per kWh. This is relatively high for coal fired power plants in the region of the country which is why the unit is primarily used for capacity and dispatched mostly as a peaking unit and for market sales. In addition, the seven year average EFOR of 21.2 percent is considered high when compared to other coal fired power plants in the region.

Remaining Useful Life

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 HEP and hangers. A consistent program like this for monitoring status and identifying areas to address in future budgets is consistent with sound maintenance practices. The HEP and hanger review addresses the concern over creep damage with an aging plant. This review program is critical and is currently being performed on all the units. The spreadsheet does indicate that a HEP and hanger review occurs on all the units. The Reid Plant has not been run as many hours per year as other facilities and is in excellent condition for its age. Provided that Big Rivers will be able to perform future major maintenance in a manner consistent with prudent utility operations, from a mechanical engineering perspective, this unit is estimated to be suitable for ongoing service another 12 years or longer, or until such time spare parts are not available.

D.B. WILSON STATION PLANT

Facility Description

The D. B. Wilson Plant is located at Island, Kentucky, approximately 55 miles from Henderson, Kentucky. This station consists of a single 417 MW unit commercialized in 1986. It is the newest and largest generating unit on the Big Rivers electric system. The plant site is configured for installation of one or more additional units, therefore, the plant facilities such as coal handling, water supply, ash handling, and sludge disposal all have more than adequate capacity for the current operating requirements.

Steam Turbine

The unit went commercial in 1986, and was given its first major overhaul in November 1990. The unit has typically been on a regular outage schedule of every 4 years for valves and every 8 years for major overhauls. The most recent major overhaul was in 2009 and the next is planned for 2017.

Boilers

Wilson 1 is a Foster Wheeler boiler capable of producing 3,484,000 lbs / hr of steam. The boiler appears to be in good condition. The last major boiler outage was in 2009. Tube samples were taken of the waterwalls and superheater. A map was created of the waterwall thickness readings to determine where future overlays should be installed. Tube analysis indicated a chemical clean was needed, which is scheduled for the 2013 outage. Holes in the downcomers and cracks in the shelf under the cone-topped canisters were repaired in 2009. The A platen superheater showed no significant indications of corrosion, thinning, or creep. The B platen superheater tubes were replaced in 2009. The A platen superheater is scheduled to be replaced in 2013. Cracks were found in the inlet and outlet headers. The cracks were ground down and re-examined. All of them passed the WFMT examination after being ground down. Tubes were replaced in the finish superheater and alignment castings were installed. Major pitting, metal loss, and corrosion were found in the DA tank. The high energy piping was inspected with Fluorescent Mag Particle testing or UT Shear Wave testing. There were some indications of creep in the piping. The hangers are inspected regularly and adjusted or replaced as needed. Safety valves are cleaned, inspected, and lapped regularly.

Draft System

The Wilson unit is equipped with a precipitator for particulate emission removal and has a limit of 0.03 pounds per MMBtu. The unit is equipped with a FGD which has a 90 percent SO_2 removal efficiency. The unit has a NOx limit of 0.6 pounds per MMBtu, however, the unit was retrofit in 2004 with a Babcock Borsig designed SCR capable of 90 percent NO_X removal efficiency.

Waste Disposal

The solid waste from the FGD, fly ash, and lime is sent to the on-site landfill. The site waste water is pH adjusted and metals are precipitated out. The bottom ash is dewatered and incorporated into FGD waste. The excess fly ash is marketed and sold in the region.

Water Supply Systems

The water supply for the plant is from an independent water intake structure located on the Green River. It appears unlikely that there should ever be an interruption of water supply to the plant. Green River water requires pretreatment before use in the cooling tower or other potable water systems in the plant. This pretreatment system is sized for two operational units so there should be adequate capacity.

Fuel Supply and Handling

The redundant coal delivery systems for the plant, barge, and truck permit supplying the full capacity of the plant from any one of the delivery systems.

Historical Operating Performance

Burns & McDonnell reviewed the plant's historical operating performance to verify that the generating units have competitive heat rates and are capable of providing the level of reliability necessary to meet Big Rivers' electric production requirements. A summary of operating data is provided below in Table II-12.

Table II-12: D.B. Wilson Historical Operating Performance Data

		Wilson Unit 1
Gross Generation Capacity	(MW)	440 MW
Net Generation Capacity	(MW)	417 MW
8 Year Average Capacity Factor	(%)	89.9%
2011 Adjusted Net Heat Rate	(Btu/kWh)	10,752
7 Year Average EFOR	(%)	4.6%

Wilson has been performing well. The 2011 adjusted net heat rate was only 10,752 Btu per kWh, which is competitive with other coal fired power plants in the region. The seven year average EFOR was 4.6 percent.

Remaining Useful Life

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 HEP and hangers. A program like this for monitoring status and identifying areas to address in future budgets is consistent with sound maintenance practices. The HEP and hanger review addresses the concern over creep damage with an aging plant. This review program is critical and is currently being performed on all the units. The spreadsheet does indicate that a HEP and hanger review occurs on all the units. The details provided for the Wilson unit are the most comprehensive and complete. The Wilson Plant is in very good condition for its age and service requirements. Provided that Big Rivers will be able to perform future major maintenance in a manner consistent with prudent utility operations, from a mechanical engineering perspective, this unit could possibly be run for another 29 to 38 years of service.

KENNETH C. COLEMAN PLANT

Facility Description

The Kenneth C. Coleman Plant consists of three coal-fired, steam turbine generating units located near Hawesville, Kentucky, approximately 60 miles east of Henderson, Kentucky. The plant is located on the west bank of the Ohio River. The land to the south is owned by Century Aluminum and is the site of an aluminum reduction plant, a primary customer of power from the Coleman Plant. The plant is located on the flood plain of the Ohio River and operation could be affected by extreme flood levels. In the past, the plant has experienced temporary isolation due to flooding of local access roads. However, the main plant area is located at a sufficient elevation to ensure that 100-year floods should not affect the plant's generation capabilities. Although a flood in excess of 100-year levels potentially could cause temporary interruptions of generating capability, this would not be anticipated to result in major disaster.

Coleman 1 was commercialized in 1969 and is rated for 150 MW of net capacity. The unit is equipped with a Foster Wheeler boiler capable of producing 1,220,000 pounds per hour of steam, and a Westinghouse turbine-generator with nameplate capacity of 160,000 kW. Coleman 2 was commercialized in 1970 and is rated for 138 MW of net capacity. The unit is equipped with a Foster Wheeler boiler capable of producing 1,220,000 pounds per hour of steam, and a Westinghouse turbine-generator with nameplate capacity of 160,000 kW. Coleman 3 was commercialized in 1972 and is rated for 155 MW of net capacity. The unit is equipped with a Riley boiler capable of producing 1,160,000 pounds per hour of steam, and a General Electric turbine-generator with nameplate capacity of 160,000 kW.

Steam Turbines

Turbines are being overhauled on a regular schedule, and the description of the maintenance activities required for the turbine appears to be normal for the age and type of machine. Turbine-generator 1 was last overhauled in 2008. At that time several of the L-2 blades required replacement. The turbine reheat stop valve bonnet studs were replaced. The turbine shaft was ruggedized and L-O turbine-generator end blades repaired. Turbine-generator 2 was last overhauled in 2007. During the overhaul thermocouples were installed in the turbine bearing and pedestals, the turbine-generator valve seats were restored, and the online filtration system was repaired. Turbine-generator 3 is scheduled to be overhauled in 2014. The turbines at the Coleman station appear to be maintained in satisfactory condition. The turbine overhaul schedules are typical for utility stations.

Boilers

Boiler 1 appears to be in reasonably good condition. Waterwall and arch tube samples taken during the 2008 outage proved the tubes to be in good condition, with waterside deposits limited, only minor pitting, and insignificant wall loss. A chemical cleaning is scheduled for 2013. Superheater tubes assessed during the 2008 outage showed significant wall loss due to fireside coal-ash corrosion. Creep analysis indicated that the tubes are below the minimum curve for creep. A repeat assessment of the superheater tubes has been recommended for 2013. The high temperature reheat tubes underwent extensive NDE and isolated tube replacement was performed during planned 2008 outage. NDE found that the leading edge tube of many of the assemblies were thin. Replacement of this section is scheduled for 2013. All soot blower lanes are shielded, and the shields are replaced when deficiencies are found. All piping supports appear to be in good condition and operating properly.

Boiler 2 appears to be in good condition. Waterwall and arch tube samples taken during the 2007 outage showed no significant deficiencies. The economizer life assessment reported the tubes to be in excellent condition and showed negligible corrosion and no evidence of microstructural degradation. The superheater and reheater showed no evidence of overheating or creep. All soot blower lanes are shielded, and all piping supports appear to be in good condition.

Boiler 3 appears to be in good condition. Economizer, waterwall, and arch tube samples taken during the 2009 outage showed minimal wall thinning, typical microstructure, and no thermal degradation. The stainless steel tubes in the reheater showed no evidence of creep or overheat, and none of the measured wall thickness values were below Minimum Wall Thickness (MWT). Ultrasonic Testing and Magnetic Testing of the welds on the high energy piping showed no relevant indications. All supports were found to be in good condition and did not require service.

Draft System

Low NO_X burners were installed and resulted in NO_X levels for all three units of below 0.5 lbs per MMBtu. In 2004 all three boilers were retrofitted with over fire air combustion equipment to further reduce NO_X emissions. In 2006 the Station was retrofitted with a Wheelabrator Air Pollution Control designed limestone scrubber that combines all three generation units into a single FGD absorber capable of 95 percent SO_2 removal.

Waste Disposal

Aside from the circulating water, all plant discharges, including the coal pile runoff, are directed to a newer ash pond. This newer ash pond is a clay-lined structure, which was designed to meet NPDES requirements at the time of its construction in 1980. The bottom ash system sluices directly into the ponds. The required operating time appears to have adequate margin for reliable operation. The site is large enough to accommodate the waste disposal requirements for quite a few years, as long as the plant continues the current practice of dredging the ash pond and disposing of ash off site. The fly ash system is conventional sluice water driven hydrovactor that discharges to an air-separating tank. The fly ash is then ponded with the bottom ash.

Water Supply Systems

The plant cooling water system is a direct, once-through cooling design supplied by the Ohio River. This system was in existence before restrictions on temperature rise or discharge requirements were placed in effect for the Ohio River. Because these units are grandfathered, it is not anticipated that the circulating water supply system design will have to be changed in the future. The plant water supply for service water, demineralizer makeup, and other clear water surfaces originally came from wells located fairly close to the Coleman Plant. As time passed, those wells began to show high mineral content and, therefore, new wells were constructed further out toward the perimeter of the property. These newer wells also began to show high mineral content. The source of the elevated mineral content in the groundwater is believed to have been at least partially derived from an adjacent superfund site. This deteriorating plant service water quality has caused the plant to make two modifications within the last few years. First, a reverse osmosis (RO) unit was installed to act as a pre-filter for the demineralizers. This has brought the demineralizers within normal operating capability to supply water to the system, since the RO unit removes about 90 percent of the total dissolved solids in the input water. The second modification was to bring in rural water district potable water into the plant. A sizable water main was installed from the main supply near the access highway to bring potable water to the plant. The well system is still used to supply all the plant service water requirements except potable water.

Fuel Supply and Handling

The Coleman Plant burns coal as the main fuel. Propane and natural gas are available as ignition fuels only. These fuels cannot generate enough steam to accomplish anything more than to start up the units. With the addition of the FGD in 2006 the plant now has the ability to burn high sulfur coal. The majority of the plant's coal supply is purchased on short-term contracts (less than five years), supplemented by spot market purchases. There appears to be adequate coal supply available to accommodate operation of the Coleman Plant for the foreseeable future. The mills have had gear reducer replacements and liner replacements on an as-needed basis.

Historical Operating Performance

Burns & McDonnell reviewed the plant's historical operating performance to verify that the generating units have competitive heat rates and are capable of providing the level of reliability to meet Big Rivers' electric production requirements. A summary of operating data is provided below in Table II-13.

Table II-13: Kenneth C. Coleman Historical Operating Performance Data

		Coleman Unit 1	Coleman Unit 2	Coleman Unit 3
Gross Generation Capacity	(MW)	160 MW	160 MW	165 MW
Net Generation Capacity	(MW)	150 MW	138 MW	155 MW
8 Year Average Capacity Factor	(%)	89.3%	92.6%	92.1%
2011 Adjusted Net Heat Rate	(Btu/kWh)	10,656	11,537	10,609
7 Year Average EFOR	(%)	4.8%	2.7%	5.9%

All three Coleman units have been performing well. Coleman Units 1, 2, and 3 had 2011 adjusted net heat rates of 10,656; 11,537; and 10,609 Btu per kWh, respectively. The availability of the units has also been good. Coleman Unit 1 had a seven year average EFOR of 4.8 percent, Coleman Unit 2 had a seven year average EFOR of 2.7 percent, and Coleman Unit 3 had a seven year average EFOR of 5.9 percent.

Remaining Useful Life

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 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 review program is critical and is currently being performed on all the units. The spreadsheet does indicate that a HEP and hanger review occurs on all the units.

Coleman Units 1, 2, and 3 are in good condition for their age and type. Provided that Big Rivers will be able to perform future major maintenance in a manner consistent with prudent utility operations, from a mechanical engineering perspective, the facility can be expected to give satisfactory service for another 11 to 21 years (depending on how it is operated).

ROBERT A. REID COMBUSTION TURBINE

Facility Description

This General Electric Frame 7 combustion turbine was placed in operation in 1976, with a net output rating of 65 MW. It is capable of firing #2 fuel oil or natural gas. Considered part of the Reid station, this unit is also located at the Sebree, Kentucky site with the HMP&L Station Two and Green stations.

Remaining Useful Life

The relatively low number of operating hours for the Reid combustion turbine indicates that, with continued maintenance it should provide reasonably available capacity for a number of years into the future provided that Big Rivers will be able to perform future major maintenance in a manner consistent with prudent utility operations.

TRANSMISSION ASSETS

This section of the Study summarizes the engineering assessment of the major electric substation assets of Big Rivers that were in service as of July 31, 2012. The Kentucky Public Service Commission mandated that Big Rivers conduct a new depreciation study as part of its submission in connection with the its intent to file for a general review of its operations and tariffs within three years. During the Study, the following efforts were conducted to examine Big Rivers' substations in service from an engineering perspective:

1. Review of Big Rivers' retirement records and history
2. Analysis of current operating and maintenance programs as well as each facility's current operating conditions
3. Analysis of the external or environmental factors that may impact the depreciation rates
4. Estimation of the remaining service life of major transmission facilities

The engineering assessment presented in this part of the Study report addresses each of the above areas. The analyses leading to formulation of proposed new depreciation rates for Big Rivers are described in Part III of the Study.

Remaining Unit Life

Estimated remaining useful lives for Big Rivers' transmission assets were based primarily on national industry standards regarding the expected useful life of major electric substation equipment.

Burns & McDonnell recommends that Big Rivers continue to follow a comprehensive program of testing on all major equipment approaching the manufacturer service limits. Individual components should be either repaired or replaced as damage is identified. Certain tests should continue to be performed on an annual basis, such as analysis of oil samples retrieved from transformers. Other tests, such as thermal imaging of electrical connections, can be done less frequently.

Electrical insulation is subject to loss of dielectric capability, particularly when subjected to heat. Testing programs are generally able to determine the capability of the components, so replacement or repairs can be initiated before the component affects the plant capability or availability. These programs must be implemented and the frequency increased as the equipment ages.

Several of the Big Rivers transmission substations are approaching the age when an electrical insulation testing program should be (and is) performed. Assuming the testing recommended is conducted and assuming any damaged components are either repaired or replaced, there would be no reason, from an electrical engineering perspective, that all of Big Rivers' transmission substations cannot remain in service for a long time.

Burns & McDonnell further considered the results of the previously completed on-site assessments of the major Big Rivers transmission substations in the estimation of the remaining useful lives. The assessments of the major transmission substations are presented in the remainder of this part of the Study.

ROBERT A. REID EHV SUBSTATION

Facility Description

The Reid EHV Substation is a 345kV to 161kV electric substation. The substation contains two 345/161kV transformers, two 345kV circuit switchers and seven 161kV circuit breakers. The substation also contains a 161kV circuit breaker that is owned by the City as part of the City's transmission loop.

A control building located within the substation contains all of the electrical controls associated with the both the circuit switchers and breakers. The control building also houses all of the protection equipment needed to provide adequate electrical protection for both the substation transformers and the associated transmission lines that enter and exit the substation.

Condition Assessment

A physical observation of the Reid EHV substation was made on August 23, 2010. The nameplates on the major substation equipment state the equipment was constructed and installed in 1982. The substation appears to be in good working condition. There are no signs of deterioration or rust located on the steel structures or any of the major equipment. Also, there are no signs of current or past oil leaks from any of the oil insulated equipment.

Maintenance

Based on all observations of the electric substation, maintenance of the major equipment appears to have been performed on a regular basis. The transformers and circuit breakers will need to continue to have regular maintenance in order to maintain good working order.

Remaining Life Assessment

The Reid EHV substation is approximately 30 years old. Assuming a continued level of maintenance on the substation, the Reid substation as a whole can expect to function properly for an additional 27 to 28 years. This results in a projected retirement year for the substation of 2040. For the major equipment located within the substation, such as the transformers, circuit breakers, and control building, this equipment requires a greater level of care and maintenance in order to function for an additional 27 to 28 years. Typically, substation transformers and circuit breakers begin being replaced once they have achieved 40 years of useful life. However, given regular and proper maintenance, this equipment can last 55 to 60 years, depending on the ambient conditions. Associated equipment, such as steel structures, concrete foundations, chain link fences, and other equipment are subject to weather conditions and deteriorate at the same speed as those same types of structures located in other types of facilities.

KENNETH C. COLEMAN EHV SUBSTATION

Facility Description

The Coleman EHV Substation is located near Hawesville, Kentucky, approximately 60 miles east of Henderson, Kentucky. The electric substation is located adjacent to the Kenneth C. Coleman Generating Facility. The Coleman EHV Substation is a 345kV to 161kV electric substation. The substation contains two 345/161kV transformers, two 345kV circuit switchers and eight 161kV circuit breakers.

A control building located within the substation contains all of the electrical controls associated with the both the circuit switchers and breakers. The control building also houses all of the protection equipment needed to provide adequate protection for both the substation transformers and the associated transmission lines that enter and exit the substation.

Maintenance

Based on all observations of the electric substation, maintenance of the major equipment appears to have been performed on a regular basis. The transformers and circuit breakers will need to continue to have regular maintenance performed on these devices in order to maintain good working order.

Condition Assessment

A physical observation of the Coleman EHV substation was made on August 23, 2010. The nameplates on the major substation equipment state the equipment was constructed and installed in 1987. The substation appears to be in good working condition. There are no signs of deterioration or rust located on the steel structures or equipment. Also, there are no signs of current or past oil leaks from any of the oil insulated equipment.

Remaining Life Assessment

The Coleman EHV substation is approximately 25 years old. Assuming a continued level of maintenance on the substation, the Coleman substation as a whole can expect to function properly for an additional 32 to 33 years. This results in a projected retirement year for the unit of 2045. For the major equipment located within the substation, such as the transformers, circuit breakers, and control building, this equipment requires a greater level of care and maintenance in order to function for an additional 32 to 33 years. Typically, substation transformers and circuit breakers are replaced any time after 40 years of useful life has passed. However, given regular and proper maintenance, this equipment can last 55 to 60 years, depending on the ambient conditions. Associated equipment, such as steel structures, concrete foundations, chain link fences, and other equipment are subject to weather conditions and deteriorate at the same speed as those same types of structures located in other types of facilities.

D. B. WILSON STATION EHV SUBSTATION

Facility Description

The Wilson EHV Substation is located at Island, Kentucky, approximately 55 miles from Henderson, Kentucky. This station is located through the entrance to the D.B. Wilson Generating Plant, and is a 345kV to 161kV electric substation. The station currently has two 345/161kV transformers, four 345kV circuit breakers and five 161kV circuit breakers.

A control building located within the substation contains all of the electrical controls associated with the both the circuit switchers and breakers. The control building also houses all of the protection equipment needed to provide adequate protection for both the substation transformers and the associated transmission lines that enter and exit the substation.

Maintenance

Based on all observations of the electric substation, maintenance of the major equipment appears to have been performed on a regular basis. One of the 161kV circuit breakers has been replaced, thus eliminating one of the original oil circuit breakers and installing the newer SF6 type gas circuit breakers. The transformers and circuit breakers will need to have regular maintenance continued on these devices in order to maintain good working order.

Condition Assessment

A physical observation of the Wilson EHV substation was made on August 23, 2010. The nameplates on the major substation equipment state the equipment was constructed and installed in 1982. The substation appears to be in good working condition. There are no signs of deterioration or rust located on the steel structures or equipment. Also, there are no signs of current or past oil leaks from any of the oil insulated equipment.

Remaining Life Assessment

The Wilson EHV substation is approximately 30 years old. Assuming a continued level of maintenance on the substation, the Wilson substation as a whole can expect to function properly for an additional 27 to 28 years. This results in a projected retirement year for the unit of 2040. For the major equipment located within the substation, such as the transformers, circuit breakers, and control building, this equipment requires a greater level of care and maintenance in order to function for an additional 27 to 28 years. Typically, substation transformers and circuit breakers are replaced any time after 40 years of useful life. However, given regular and proper maintenance, this equipment can last 55 to 60 years, depending on ambient conditions. Associated equipment, such as steel structures, concrete foundations, chain link fences, and other equipment are subject to weather conditions and deteriorate at the same speed as those same types of structures located in other types of facilities.

HANCOCK SUBSTATION

Facility Description

The Hancock Substation is located near Hawesville, Kentucky, approximately 60 miles east of Henderson, Kentucky. This substation is located within five miles of the Kenneth C. Coleman Generating Station, and is a 161kV to 69kV electric substation. The station currently has two 161/69kV transformers, five 161kV circuit breakers and four 69kV circuit breakers.

A control building located within the substation contains all of the electrical controls associated with the both the circuit switchers and breakers. The control building also houses all of the protection equipment needed to provide adequate protection for both the substation transformers and the associated transmission lines that enter and exit the substation.

Condition Assessment

A physical observation of the Hancock substation was made on August 23, 2010. The 161kV circuit breakers contained nameplates that state the breakers were manufactured in 2001. However, the substation is far greater in age than the circuit breakers. Located throughout the substation were brown colored glass insulators. This particular style of insulator has not been manufactured by major electric manufacturers since the 1960's. The existing steel structures were beginning to show signs of rust and deterioration, which is expected given the estimated age of the substation.

Maintenance

All of the 161kV circuit breakers had been replaced in 2001, eliminating the original oil circuit breakers and installing newer SF6 type gas circuit breakers. Based on the estimated age of the substation, additional maintenance will need to be performed on the transformers and the remaining oil circuit breakers will need to have regular maintenance continued on these devices in order to maintain good working order. Also, there are no signs of current or past oil leaks from any of the oil insulated equipment.

Remaining Life Assessment

The Hancock Substation is approximately 42 years old. Typically, substation transformers and circuit breakers are replaced any time after 40 years of useful life. However, given regular and proper maintenance, this equipment can last between 50 and 60 years. Brown insulators are considered obsolete by industry standards, and may need to be considered as part of future maintenance work. However, assuming a continued level of maintenance on the substation, the Hancock substation appears to be in good working order and should continue to function properly for an additional 17 to 18 years. This resulted in a projected retirement year for the unit of 2030. For the major oil filled equipment located within the substation, such as the transformers and circuit breakers, this equipment requires a greater level of care and maintenance in order to function for an additional 17 to 18 years.

HARDINSBURG SUBSTATION

Facility Description

The Hardinsburg Substation is located near Hardinsburg, Kentucky, approximately 80 miles east of Henderson, Kentucky. This substation is a 161kV to 69kV electric substation. The station currently has two 161/69kV transformers, five 161kV circuit breakers and seven 69kV circuit breakers.

A control building located within the substation contains all of the electrical controls associated with the both the circuit switchers and breakers. The control building also houses all of the protection equipment needed to provide adequate protection for both the substation transformers and the associated transmission lines that enter and exit the substation.

Condition Assessment

A physical observation of the Hardinsburg substation was made on August 23, 2010. The equipment located within the substation contained nameplates stating their construction in 1968. The steel structures were beginning to show signs of rust and deterioration, which is expected given the estimated age of the substation. However the concrete foundations, ground and conduit connections appeared to be in good operating shape.

Maintenance

Based on the age of the substation, maintenance will need to be performed on the transformers and oil circuit breakers in order to maintain good working order. There were no signs of past or current oil leaks from existing equipment. This demonstrates that the equipment is being properly inspected and maintained on a regular basis.

Remaining Life Assessment

The Hardinsburg Substation is approximately 44 years old. Typically, substation transformers and circuit breakers are replaced any time after 40 years of useful life. However, given regular and proper maintenance, this equipment can last between 50 and 60 years. Assuming a continued level of maintenance on the substation, the Hardinsburg substation appears to be in good working order and should continue to function properly for an additional 17 to 18 years. This results in a projected retirement year for the unit of 2030. For the major oil filled equipment located within the substation, such as the transformers and circuit breakers, this equipment requires a greater level of care and maintenance in order to function for an additional 17 to 18 years.

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PART III – DEPRECIATION RATE ANALYSIS

PART III
DEPRECIATION RATE ANALYSIS

Part III of the Study describes the methodology and presents the results of the analysis performed in the formulation of proposed new depreciation rates for the electric generation, transmission, and general plant assets of Big Rivers. The depreciation rate analysis was performed based on the electric generation, transmission, and general plant historical accounting records of Big Rivers as of July 31, 2012. The methodologies and basis for calculating the proposed depreciation rates and completing this Study is similar to the process utilized in completing the 2010 Study.

STUDY SCOPE & PURPOSE

This depreciation rate analysis was conducted to analyze the service life characteristics, net salvage indications, and depreciation reserve status based on historical data from Big Rivers' CPR system data, and then to derive appropriate depreciation rates for Big Rivers' system plant in service.

The procedures used to analyze Big Rivers' historical data pertaining to useful service lives and net salvage rates are discussed for the assets represented by each plant account. This narrative description of the depreciation rate analysis completed for Big Rivers includes a variety of concepts related to common utility depreciation terminology and study techniques. Various reference materials are readily available that provide thorough explanations of these concepts.[1]

For plant assets in certain accounts there was found to be an insufficient amount of historical plant additions and retirement data in the CPR system on which to perform statistically valid actuarial studies. In these cases, estimates were made based on the historical data from similar accounts, industry standards, and the Engineer's Assessment in Section II. This data, combined with the judgment of the depreciation consultants, was relied upon in the completion of the analysis for those accounts with limited historical data. However, the consideration given to

[1] For further information, refer to industry publications "Public Utility Depreciation Practices", National Association of Regulatory Utility Commissioners (NARUC), August 1996 and "Depreciation Systems", Wolf, Frank and Fitch, Chester, Iowa State University Press, 1994.

extending useful lives is based on the assumption that Big Rivers will be able to perform future major maintenance in a manner consistent with prudent utility operations.

DEPRECIATION RATE STUDY METHODS

Two primary methods have been used to calculate depreciation accruals: the Whole Life method (most General Plant accounts) and the Life Span method combined with the Remaining Life technique (all Transmission accounts and all Production accounts and Account 390 – Structures).

Whole Life Method

For each account where used, the Whole Life method uses the account average service life (ASL) and the average net salvage percentage (NS) for the account to calculate the annual depreciation rate according to the following formula.

$$\frac{1-NS}{ASL}$$

Whole life depreciation rates are appropriate for mass property type of accounts where there are a large number of relatively small property units with no definite or planned final retirement, retirements of individual units are independent of each other, and additions are generally independent of existing units. Typical property falling in this category includes tools, vehicles, computers, and furniture.

Estimates of average service life and dispersion were studied using the retirement rate method of actuarial analysis based upon the historical nature of the characteristics of the plant retired from each account since inception. Accounts for which insufficient retirement activity had occurred on which to conduct actuarial analysis, or the results of such an analysis were inconclusive, other publicly available industry information and the judgment of the depreciation consultant were relied upon to estimate reasonable average service lives and/or average net salvage values.

Life Span Method

The Life Span method calculates lives for an asset group or account based on the assumption that all property units in the group will retire concurrently at a single forecasted point in time, whether the units are part of the initial installation or later additions. Typical property falling in this category includes poles, transformers, conductors, power production facilities and buildings. Forecasting reasonable retirement dates is the most critical aspect of the Life Span method.

During the life of an operational power plant and building, portions of the facility are retired and replaced. These items typically include roofs, HVAC equipment, boiler tubes and walls, pumps, piping, and parking lots allocated to the cost of the facility. Because not all items of plant live the entire length of time a power plant or building remains in service, these so-called interim retirements tend to decrease the life of the dollars in the group or account. Therefore, it is important in a depreciation study to analyze the historical interim retirement amounts and whether the interim retirement rates are expected to continue at the same pace over the remaining life of the unit. Interim retirements can be studied mathematically using the system of Iowa curves, the Gompertz-Makeham formula, or derived interim retirement rate curves. As the information was readily available, interim retirement life tables were developed separately for each of the accounts under the Life Span method.

Although detailed interim retirement records are maintained for each Cooperative building and production facility, interim retirements for most locations are relatively few and little applicable life knowledge would be derived from attempting an analysis on such a thin available data set. Therefore, to improve the validity of the interim retirement rate analysis, an interim retirement rate calculation was performed for each account as a whole, rather than by account and then by location.

Engineers assessed the Big Rivers electric plant facilities regarding their design, performance, operation and maintenance, and condition, and provided estimates of final retirement dates for each production plant and each general plant structure to the depreciation consultant as input to the depreciation model. The Engineering Assessment of the major system facilities is provided in Part II of the Study. For each production account and buildings account, an average year of final retirement (AYFR) was calculated for each major facility using the direct weighted average of individual retirement years and plant balances. This AYFR and the aforementioned interim retirement rates are inputs to the remaining life (RL) calculation for each account.

The Remaining Life depreciation rate automatically adjusts for past under- and over-accruals by building those amounts into the depreciation rate calculation using the reserve ratio (RR). The RR is the depreciation reserve amount divided by the plant balance at the point in time of the study (July 31, 2012). The net salvage parameter in the Remaining Life rate equation is the future net salvage rate (FS). The Remaining Life depreciation rate is expressed mathematically below.

$$\frac{1 - FS - RR}{\text{Remaining Life}}$$

Sources of Industry Information

Actuarial methods are most accurate and applicable to determination of historic trends for assessing average service lives and salvage specific to a plant account when there is significant annual turnover of plant in that account. However, the limited activity in several accounts prevented actuarial analysis.

Accounts for which insufficient retirement activity had occurred on which to conduct actuarial analysis, or for which the results of such an analysis were inconclusive, other publicly available industry information, the Engineer's Assessment in Section II and the judgment of the depreciation consultant were relied upon to estimate reasonable average service lives. Three engineering publications that provide electric industry information were also considered as a resource for making certain assumptions or for the evaluation of lifespan and salvage value parameters:

1. "Depreciation Statistics from 100 Large United States Electric Utilities – FERC Jurisdiction", Society of Depreciation Professionals Journal, Mougin, Clarence, 1992. (hereinafter "SDP report").

2. "A Survey of Depreciation Statistics", Edison Electric Institute, Robinson, Earl, 1995. (hereinafter "EEI report").

3. "Power Plant Removal Costs Revisited", Society of Depreciation Professionals Journal, Ferguson, John, 1997. (hereinafter "Ferguson report").

Net Salvage Factors

For this Study, Big Rivers provided salvage values and removal costs for 2010 and 2011. Including very large removal costs incurred by Big Rivers in 2010 and 2011 resulted in unrealistic net salvage factors. Therefore, the net salvage factors for each production, transmission, and general plant account were taken directly from the net salvage analysis performed in the 2010 Study. The net salvage factors provided in the 2010 Study are calculated as an average of the available historical data by system account from 1965 to 1998 and estimated values from 1998 to 2010. The net salvage figures used in the depreciation rate formulas in the 2010 Study are for final net salvage, i.e. the gross proceeds realized less any removal cost to raze the structures represented in the account, if any.

The removal costs incurred by Big Rivers total $6.7 million in 2010 and $1.8 million in 2011. For perspective, Big Rivers' removal costs for the entire period from 1965 to 2010 were only $6.4 million. The large removal costs incurred by Big Rivers in 2010 and 2011were actually incurred, and do not appear unreasonable given the refurbishment retirements incurred at Wilson. However, Big Rivers' management decided that due to the short period of time since the 2010 Study was completed and approved and the expedited timeframe required for this report it would be appropriate to use net salvage factors that are consistent with the 2010 Study. The analysis required to incorporate the 2010 and 2011 removal costs in Big Rivers proposed depreciation rates has been deferred and will be addressed in a future depreciation study.

DEPRECIATION RATE ANALYSIS

Table III-1 summarizes the results of the depreciation rate analysis by capital plant account balance as of July 31, 2012. Table III-1 shows the existing depreciation rates and annual depreciation expense compared to the proposed depreciation rates and annual depreciation expense. Table III-1 also shows the July 31, 2012 plant account balances, reserve ratios, average service lives, remaining service lives and net salvage factors.

Table III-1: 2012 Depreciation Rate Study Summary

Account	Description	As of July 31, 2012 Plant Balance - $ -	Reserve Balance - $ -	Reserve Ratio	Existing Depreciation Rate - % -	Average Service Life - Years -	Remaining Service Life - Years -	Net Salvage Factor - % -	Proposed Depreciation Rate - % -	Annual Depreciation Expense Existing - $ -	Proposed - $ -	Variance - $ -
310	Land & Land Improvements	4,537,577	0									
PRODUCTION PLANT [1]												
340	Land	475,968	0									
311	Structures	125,693,531	82,324,994	65.5	1.38%	62.0	28.2	-4.5%	1.38%	1,734,571	1,737,612	3,041
312	Boiler Plant	680,885,710	356,227,283	52.3	1.88%	59.5	26.1	-5.0%	2.02%	12,800,651	13,732,241	931,589
312 A-K	Boiler Plant - Environment Compliance	577,753,481	222,781,719	38.6	2.28%	53.0	26.1	-2.0%	2.43%	13,172,779	14,016,172	843,392
312 L-P	Short-Life Production Plant -Environmental	13,034,034	3,069,236	23.5	20.22%	10.0	4.8	0.0%	15.95%	2,635,482	2,078,941	(556,541)
312 V-Z	Short-Life Production Plant -Other	721,531	(178,280)	-24.7	14.39%	10.0	4.9	0.0%	25.38%	103,828	183,151	79,323
314	Turbine	230,546,435	129,685,979	56.3	1.91%	59.5	26.5	-8.2%	1.96%	4,403,437	4,511,020	107,583
315	Electric Equipment	62,213,068	37,265,920	59.9	1.99%	50.9	18.3	3.0%	2.03%	1,238,040	1,261,703	23,663
316	Miscellaneous Equipment	4,745,114	60,556	1.3	3.78%	57.5	24.3	0.5%	4.04%	179,365	191,836	12,471
341	CT - Structures	154,233	122,610	79.5	1.17%	52.5	19.4	0.0%	1.06%	1,805	1,633	(172)
342	CT - Fuel Holders & Access.	1,442,387	641,686	44.5	9.10%	52.5	19.2	-134.8%	9.92%	131,257	143,063	11,806
343	CT - Prime Movers	4,915,886	3,929,184	79.9	3.02%	52.5	19.4	-38.3%	3.02%	148,460	148,316	(144)
344	CT - Generators	1,102,964	1,027,096	93.1	0.50%	52.5	19.5	0.0%	0.35%	5,515	3,891	(1,624)
345	CT - Accessory Electrical Equipment	399,274	178,372	44.7	2.05%	52.5	18.9	0.0%	2.93%	8,185	11,683	3,498
	Subtotal	1,708,621,193	837,136,354							36,563,375	38,021,262	1,457,887
TRANSMISSION [1]												
350	Land	704,868	0									
352	Structures	6,872,307	3,939,593	57.3	1.90%	52.5	23.3	-2.4%	1.94%	130,574	133,325	2,752
353	Station Equipment	123,005,428	57,372,818	46.6	2.23%	52.5	23.4	-0.2%	2.29%	2,743,021	2,818,401	75,380
354	Towers	8,593,544	5,258,193	61.2	1.42%	57.5	28.5	0.0%	1.36%	122,028	117,062	(4,967)
355	Poles	42,531,008	24,872,625	58.5	2.06%	49.5	20.5	0.0%	2.03%	876,139	861,385	(14,754)
356	Lines	43,877,088	25,179,681	57.4	1.69%	52.5	23.5	0.0%	1.81%	741,523	795,634	54,112
	Subtotal	225,584,244	116,622,910							4,613,285	4,725,807	112,523
GENERAL PLANT [2]												
389	Land	407,251	0									
390	Structures [1]	5,263,520	1,841,773	35.0	2.84%	42.5	11.5	21.8%	3.76%	149,484	198,151	48,667
391.0/391.6/391.7	Office Furniture & Equipment	797,888	(226,065)	-28.3	17.12%	10.0	6.0	8.9%	9.11%	136,598	72,724	(63,875)
391.2, 391.3	Computer	20,489,975	2,105,972	10.3	10.29%	10.0	4.8	1.2%	9.88%	2,108,418	2,024,934	(83,484)
392.2	Vehicles - General	2,085,515	1,222,328	58.6	4.39%	10.0	3.0	14.2%	8.58%	91,554	179,034	87,480
392.3	Vehicles - Transmission	1,257,240	788,792	62.7	6.14%	10.0	4.7	16.9%	8.31%	77,195	104,450	27,256
393	Stores Equipment	98,766	77,948	78.9	4.40%	16.0	5.2	4.4%	5.97%	4,346	5,900	1,554
394	Tools	731,818	441,711	60.4	4.61%	16.0	8.2	2.7%	6.08%	33,737	44,482	10,745
395	Lab Equipment	221,279	176,719	79.9	4.41%	16.0	5.7	2.1%	6.12%	9,758	13,541	3,783
396	Power Operated Equipment	567,875	423,883	74.6	3.70%	16.0	5.6	24.9%	4.69%	21,011	26,644	5,632
397	Communication Equipment	1,670,551	1,488,248	89.1	4.35%	16.0	1.0	-0.1%	6.25%	72,669	104,474	31,805
398	Miscellaneous Equipment	251,254	44,367	17.7	11.80%	16.0	9.0	3.2%	6.05%	29,648	15,200	(14,448)
	Subtotal	33,842,932	8,385,678							2,734,419	2,789,533	55,115
TOTAL		$1,968,115,264	$962,144,943							$43,911,079	$45,536,603	$1,625,524

[1] Life Span Method depreciation

[2] Whole Life Method depreciation

The existing depreciation rates in effect for Big Rivers' system assets were developed in the previous depreciation study based on the April 30, 2010 plant in service. The annual depreciation expense calculated in Table III-1 based on the application of the **existing depreciation rates** to the July 31, 2012 plant balances is approximately **$43.9 million.**

The application of the **proposed depreciation rates** to the July 31, 2012 plant balances resulted in calculated total annual depreciation expense of approximately **$45.5 million.**

This results in an **increase** in Big Rivers' total annual depreciation expense of approximately **$1.6 million, or 3.7%.**

Discussion of the depreciation analysis performed on each Big Rivers plant category or account that resulted in the information shown in Table III-1 is presented below. Detailed calculations for all the accounts shown in Table III-1 are provided in Appendix A.

Steam Production Plant: Accounts 311 to 316

Actuarial analyses based on historical data obtained from Big Rivers CPR system were used to develop the depreciation rates and remaining life for Accounts 311 to 315. Insufficient plant additions prior to retirement activity prevented a reliable actuarial analysis of Account 316 - Miscellaneous Equipment.

The current best estimates of future retirement dates for each generating station as described in Part II: Engineering Assessment were also used as inputs to the Life Span model along with the actuarial analysis and engineers' judgment for each plant account. The life of these individual units can vary based on a number of factors including but not limited to operating hours and maintenance. The Green, HMP&L Station Two and Coleman facilities have multiple units, but are forecasted to retire in the same year. This is reasonable for three reasons. First, the units were installed within two to three years of each other. Second, most plant accounts are assigned to the entire generating station, not to individual units of the facility. Most importantly, it is realistic to assume that the entire facility would shut down before significant demolition activities begin to occur. Piecemeal removal at an operating facility would be costly and much of the plant infrastructure would need to remain in service in order to maintain the last unit's ability to function.

Due to the caustic nature of scrubber operations, scrubber equipment dealing with sulfur dioxide removal and related piping will be expected to have a shorter life than that expected for the vast majority of the production plant. That life expectancy is directly related to the design, wear and tear from variable amounts of daily operation, and the levels of removal based on the particular coal mix being burned.

Account 312 contains some much newer environmental compliance assets such as scrubber equipment that have a shorter expected life than the other assets in Account 312. These assets are shown in Account 312 A-K. In addition, assets such as mist eliminator panels and slag grinders with even shorter useful lives were subdivided into Account 312 V-Z and to Account 312 L-P (if they were related to environmental compliance). Despite having a shorter useful life than other assets in Account 312, the remaining life of these environmental assets is still constrained by the remaining life of the plant as a whole because the environmental assets would be retired when the overall plant is retired.

The D. B. Wilson Station is significantly newer than the other facilities. As such, its Plant Balance is significantly larger in comparison to the other facilities. If the remaining service life of each facility is weighted by the plant balances in Account 311 - Structures, Account 312 - Boiler Plant, and Account 314 - Turbine, the weighted average remaining service life is approximately 26 to 28 years. As such, the remaining service life for Account 311 - Structures was assumed to be 28 years and the remaining service life for Account 312 - Boiler Plant and Account 314 - Turbine was assumed to be 26 years.

Insufficient plant additions prior to retirement activity prevented a reliable actuarial analysis of Account 316 - Miscellaneous Equipment. As a result, other publicly available industry information, the Engineer's Assessment in Section II and the judgment of the depreciation consultant were relied upon to estimate a reasonable average service life for this account.

Other Production (Combustion Turbine): Accounts 341 to 346

The investment in Other Production accounts is related to the one 65 MW combustion turbine (CT) located at the Reid plant. These accounts were studied in a method identical to the Steam Production accounts (except Account 316): actuarial analyses based on historical data obtained from Big Rivers CPR system were used to develop the depreciation rates and remaining life for Accounts 341 to 346.

Transmission: Accounts 352 to 356

The investment in Transmission Accounts is derived from Big Rivers' structures, substations and substation equipment, transmission towers, poles and transmission lines. These accounts were studied in a method identical to the Other Production accounts: actuarial analyses based on historical data obtained from Big Rivers CPR system were used to develop the depreciation rates and remaining life for Accounts 352 to 356.

General Plant: Accounts 390 to 398

Structures: Account 390

This account contains the investment for Cooperative buildings identified as Headquarters, Transmission Office/Warehouse, Publications, Communication, Central Laboratory, and 4th Street Warehouse. Actuarial analyses based on historical data obtained from Big Rivers CPR system were used to develop the depreciation rates and remaining life for Account 390.

Office Furniture & Equipment: Accounts 391.0, 391.6 & 391.7

These accounts contain the investment for items typically found in a business office, including desks, tables, bookcases, chairs, copiers, and fax machines. Due to the similarity of content, the three sub-accounts were analyzed together. Publicly available industry information, industry standards, and the judgment of the depreciation consultant were relied upon to estimate a reasonable average service life for this account.

Computer Equipment: Accounts 391.2, 391.3

This account contains the investment for the Big Rivers computer system, software, personal computers, engineering computers, tape drives, peripherals, printers, and the facilities management system. Publicly available industry information, industry standards, and the judgment of the depreciation consultant were relied upon to estimate a reasonable average service life for this account.

Vehicles, General: Account 392.2

This account contains investment for Big Rivers' cars, vans, light and medium duty trucks, truck mounted tool cabinets, and a variety of air compressor, generator, and equipment trailers. Publicly available industry information, industry standards, and the judgment of the depreciation consultant were relied upon to estimate a reasonable average service life for this account.

Vehicles, Transmission: Account 392.3

This account contains investment for heavy-duty trucks, a crane, a lowboy, and a digger derrick. Publicly available industry information, industry standards, and the judgment of the depreciation consultant were relied upon to estimate a reasonable average service life for this account.

Stores Equipment: Account 393

This account contains investment for items typically found in a warehouse, predominantly shelves and bins. Other items include lockers, pallet movers, and a forklift. Publicly available industry information, industry standards, and the judgment of the depreciation consultant were relied upon to estimate a reasonable average service life for this account.

Tools, Shop & Garage Equipment: Account 394

This account title is most descriptive of the investment in the account. Typical items found in Account 394 include non-expensed line truck tools, test equipment, ladders, chain saws, tampers, lifts, tanks, air compressors, and an oil purification unit. Publicly available industry information, industry standards, and the judgment of the depreciation consultant were relied upon to estimate a reasonable average service life for this account.

Laboratory Equipment: Account 395

This account contains a variety of electrical and material laboratory tools, including power supplies, test gear, oscilloscopes, microscopes, analyzers, a gas chromatograph, a solvent extraction system, and a spectrophotometer. Publicly available industry information, industry standards, and the judgment of the depreciation consultant were relied upon to estimate a reasonable average service life for this account.

Power Operated Equipment: Account 396

The investment in this account includes tractors, trenchers, mowers, go-tracts, a bulldozer, and a boat and trailer. Publicly available industry information, industry standards, and the judgment of the depreciation consultant were relied upon to estimate a reasonable average service life for this account.

Communications Equipment: Account 397

The investment in this account included Motorola mobile and hand radios, mobile base radio system with console and related towers, telephone systems and upgrades, data circuits, antennas, and pagers. Publicly available industry information, industry standards, and the judgment of the depreciation consultant were relied upon to estimate a reasonable average service life for this account.

Miscellaneous Equipment: Account 398

The investment in this account includes equipment not categorized into other accounts including video equipment, cameras, kitchen equipment, vacuum cleaners, and a mobile office trailer. Publicly available industry information, industry standards, and the judgment of the depreciation consultant were relied upon to estimate a reasonable average service life for this account.

Detailed calculations for all the accounts shown in Table III-1 are provided in Appendix A.

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PART IV – SUMMARY & CONCLUSIONS

PART IV
SUMMARY & CONCLUSIONS

Burns & McDonnell has completed its assessment and analysis of the remaining useful lives and the depreciation rates pertaining to the electric plant assets of Big Rivers Electric Corporation as reflected in this 2012 Comprehensive Depreciation Study. The Study was prepared in accordance with, and satisfies the requirements of, the Rural Utilities Service as issued to Big Rivers subsequent to its last depreciation study.

The proposed depreciation rates have been developed for all of Big Rivers' generation, transmission, and general plant in service assets based on historical plant accounting records provided by Big Rivers CPR system, other published depreciation survey information, and generally accepted depreciation analysis methodologies. Based on the analysis of the information provided by Big Rivers and the results of the previously completed on-site observations of the Big Rivers generation and transmission facilities, Burns & McDonnell has formulated estimates of the remaining useful service lives for each plant account. The proposed depreciation rates, if implemented by Big Rivers, would result in an estimated increase in depreciation expense of approximately $1.6 million per year based on July 31, 2012 account balances.

Burns & McDonnell recommends that Big Rivers continues to follow a comprehensive program of testing on those units approaching the service limits in the ASTM guidelines. Individual components should be either repaired or replaced as damage is identified. Since creep stress is a long-term phenomenon, there should be adequate time to procure and schedule replacement of any damaged components. All of the Big Rivers generating units have reached the age when this testing program should be performed. This testing is currently being performed by Big Rivers and should continue to be performed.

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. Based on the assumption that Big Rivers will be able to perform future major maintenance in a manner consistent with prudent utility operations, there is no reason, from a mechanical engineering perspective, that all of Big Rivers' generating units cannot remain in service for a long time. Should major maintenance continue to be postponed, it is not likely that all of Big Rivers' generating units will remain in service as long as similar generating units.

These proposed depreciation rates are projected to increase total annual depreciation expenses of Big Rivers by approximately 3.7 percent. Therefore, Burns & McDonnell recommends to Big Rivers that it consider pursuing approval and implementation of the proposed depreciation rates for each RUS plant account as presented in this report. The existing and proposed depreciation rates are shown below in Table IV-1.

Table IV-1: Existing and Proposed Depreciation Rates

		Existing Depreciation Rate	Proposed Depreciation Rate	Variance
PRODUCTION PLANT				
311	Structures	1 38%	1 38%	0 00%
312	Boiler Plant	1 88%	2 02%	0 14%
312 A-K	Boiler Plant - Environment Compliance	2 28%	2 43%	0 15%
312 L-P	Short-Life Production Plant -Environmental	20 22%	15 95%	-4 27%
312 V-Z	Short-Life Production Plant -Other	14 39%	25 38%	10 99%
314	Turbine	1 91%	1 96%	0.05%
315	Electric Equipment	1 99%	2 03%	0 04%
316	Miscellaneous Equipment	3 78%	4 04%	0 26%
341	CT - Structures	1 17%	1 06%	-0 11%
342	CT - Fuel Holders & Access	9 10%	9 92%	0 82%
343	CT - Prime Movers	3 02%	3 02%	0.00%
344	CT - Generators	0 50%	0 35%	-0 15%
345	CT - Accessory Electrical Equipment	2.05%	2.93%	0.88%
TRANSMISSION				
352	Structures	1 90%	1 94%	0 04%
353	Station Equipment	2 23%	2 29%	0 06%
354	Towers	1 42%	1 36%	-0.06%
355	Poles	2 06%	2 03%	-0 03%
356	Lines	1.69%	1.81%	0.12%
GENERAL PLANT				
390	Structures [1]	2 84%	3 76%	0 92%
391 0/391 6/391 7	Office Furniture & Equipment	17 12%	9 11%	-8 01%
391 2	Computer	10 29%	9 88%	-0 41%
392 2	Vehicles - General	4.39%	8.58%	4 19%
392 3	Vehicles - Transmission	6 14%	8 31%	2 17%
393	Stores Equipment	4 40%	5 97%	1.57%
394	Tools	4 61%	6 08%	1 47%
395	Lab Equipment	4 41%	6 12%	1 71%
396	Power Operated Equipment	3 70%	4 69%	0 99%
397	Communication Equipment	4 35%	6 25%	1 90%
398	Miscellaneous Equipment	11.80%	6.05%	-5.75%

In the preparation of this report, the information provided by Big Rivers was used by Burns & McDonnell to make certain assumptions with respect to conditions that may exist in the future. Burns & McDonnell believes the assumptions made are reasonable for the purposes of this report and makes no representation that the conditions assumed will, in fact, occur. In addition, while Burns & McDonnell has no reason to believe that the information provided by Big Rivers, and on which was relied upon, is inaccurate in any material respect, it has not been independently verified and its accuracy or completeness cannot be guaranteed. To the extent that actual future conditions differ from those assumed herein or from the information provided, actual results may vary from those projected.

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APPENDIX A

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Burns & McDonnell SINCE 1898

Production Structures	Account:	311
Date of Retirement (Mid Year):		2041
Interim Retirement Rate:		0.00067
Study Date, Year-End:		2012
Future Life from Study Date:		28.8
Remaining Life (F/E + .5) =		28.2

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Removal Costs	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	2,387,104	0	6,879	$ 2,393,983	0.00000
1966	0	0	0	$ 2,393,983	0.00000
1967	0	0	0	$ 2,393,983	0.00000
1968	0	0	0	$ 2,393,983	0.00000
1969	5,316,911	0	4,040	$ 7,714,934	0.00000
1970	3,088,656	0	5,000	$ 10,808,590	0.00000
1971	4,646,588	0	357	$ 15,455,536	0.00000
1972	15,076	9,237	0	$ 15,461,375	0.00060
1973	37,913	0	0	$ 15,499,289	0.00000
1974	27,452	49,315	537	$ 15,477,963	0.00319
1975	466,603	10,019	298	$ 15,934,844	0.00063
1976	89,169	51,378	0	$ 15,972,635	0.00322
1977	126,318	404	0	$ 16,098,549	0.00003
1978	293,082	9,807	0	$ 16,381,824	0.00060
1979	12,146,870	6,495	3,651	$ 28,525,850	0.00023
1980	514,964	4,484	0	$ 29,036,329	0.00015
1981	13,836,470	0	1,079	$ 42,873,879	0.00000
1982	380,544	6,724	0	$ 43,247,698	0.00016
1983	591,717	582	0	$ 43,838,833	0.00001
1984	383,328	209,902	1,891	$ 44,014,150	0.00477
1985	410,671	26,160	429	$ 44,399,089	0.00059
1986	72,148,221	22,532	5,414	$ 116,530,192	0.00019
1987	60,368	15,673	0	$ 116,574,887	0.00013
1988	297,810	10,603	0	$ 116,862,094	0.00009
1989	183,496	15,906	0	$ 117,029,684	0.00014
1990	293,938	5,170	0	$ 117,318,452	0.00004
1991	160,650	1,284	0	$ 117,477,818	0.00001
1992	152,276	19,338	0	$ 117,610,756	0.00016
1993	112,866	141,852	0	$ 117,581,771	0.00121
1994	100,775	32,440	0	$ 117,650,105	0.00028
1995	9,584	292	0	$ 117,659,398	0.00000
1996	0	1,677	0	$ 117,657,720	0.00001
1997	3,083	1,701	0	$ 117,659,102	0.00001
1998	12,000	4,884	0	$ 117,666,218	0.00004
1999	104,892	130,509	0	$ 117,640,601	0.00111
2000	329,091	594,813	0	$ 117,374,879	0.00507
2001	749,931	32,702	0	$ 118,092,108	0.00028
2002	504,946	260,690	0	$ 118,336,364	0.00220
2003	751,888	100,439	0	$ 118,987,813	0.00084
2004	253,068	87,316	0	$ 119,153,566	0.00073
2005	169,285	30,893	0	$ 119,291,958	0.00026
2006	288,443	7,200	0	$ 119,573,201	0.00006
2007	299,533	19,441	0	$ 119,853,293	0.00016
2008	341,876	184,086	0	$ 120,011,083	0.00153
2009	2,356,108	39,450	0	$ 122,327,741	0.00032
2010	226,124	15,683	3,829	$ 122,542,011	0.00013
2011	1,026,685	206,474	94,078	$ 123,456,300	0.00167
TOTAL	$ 125,696,374	$ 2,367,554	$ 127,480	$ 3,512,236,416	0.00067

Interim Retirement Life Table

Year Placed	Age at 12/31/2012	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0.5	0.00067	0.99933	0.99966	27.71863
2011	1.5	0.00067	0.99933	0.99899	27.69994
2010	2.5	0.00067	0.99933	0.99832	27.68127
2009	3.5	0.00067	0.99933	0.99764	27.66261
2008	4.5	0.00067	0.99933	0.99697	27.64396
2007	5.5	0.00067	0.99933	0.99630	27.62533
2006	6.5	0.00067	0.99933	0.99563	27.60671
2005	7.5	0.00067	0.99933	0.99496	27.58810
2004	8.5	0.00067	0.99933	0.99428	27.56950
2003	9.5	0.00067	0.99933	0.99361	27.55092
2002	10.5	0.00067	0.99933	0.99294	27.53235
2001	11.5	0.00067	0.99933	0.99228	27.51379
2000	12.5	0.00067	0.99933	0.99161	27.49524
1999	13.5	0.00067	0.99933	0.99094	27.47671
1998	14.5	0.00067	0.99933	0.99027	27.45818
1997	15.5	0.00067	0.99933	0.98960	27.43968
1996	16.5	0.00067	0.99933	0.98894	27.42118
1995	17.5	0.00067	0.99933	0.98827	27.40269
1994	18.5	0.00067	0.99933	0.98760	27.38422
1993	19.5	0.00067	0.99933	0.98694	27.36576
1992	20.5	0.00067	0.99933	0.98627	27.34732
1991	21.5	0.00067	0.99933	0.98561	27.32888
1990	22.5	0.00067	0.99933	0.98494	27.31046
1989	23.5	0.00067	0.99933	0.98428	27.29205
1988	24.5	0.00067	0.99933	0.98362	27.27365
1987	25.5	0.00067	0.99933	0.98295	27.25527
1986	26.5	0.00067	0.99933	0.98229	27.23690
1985	27.5	0.00067	0.99933	0.98163	27.21854
1984	28.5	0.00067	0.99933	0.98097	27.20019
1983	29.5	0.00067	0.99933	0.98030	27.18185
1982	30.5	0.00067	0.99933	0.97964	27.16353
1981	31.5	0.00067	0.99933	0.97898	27.14522
1980	32.5	0.00067	0.99933	0.97832	26.16690
1979	33.5	0.00067	0.99933	0.97766	25.18923
1978	34.5	0.00067	0.99933	0.97700	24.21223
1977	35.5	0.00067	0.99933	0.97635	23.23588
1976	36.5	0.00067	0.99933	0.97569	22.26019
1975	37.5	0.00067	0.99933	0.97503	21.28516
1974	38.5	0.00067	0.99933	0.97437	20.31079
1973	39.5	0.00067	0.99933	0.97372	19.33707
1972	40.5	0.00067	0.99933	0.97306	18.36401
1971	41.5	0.00067	0.99933	0.97240	17.39161
1970	42.5	0.00067	0.99933	0.97175	16.41986
1969	43.5	0.00067	0.99933	0.97109	15.44877
1968	44.5	0.00067	0.99933	0.97044	14.47833
1967	45.5	0.00067	0.99933	0.96978	13.50854
1966	46.5	0.00067	0.99933	0.96913	12.53941
1965	47.5	0.00067	0.99933	0.96848	11.57094
1964	48.5	0.00067	0.99933	0.96782	10.60311
1963	49.5	0.00067	0.99933	0.96717	9.63594
1962	50.5	0.00067	0.99933	0.96652	8.66942
1961	51.5	0.00067	0.99933	0.96587	7.70355
1960	52.5	0.00067	0.99933	0.96522	6.73833
1959	53.5	0.00067	0.99933	0.96457	5.77376
1958	54.5	0.00067	0.99933	0.96392	4.80985
1957	55.5	0.00067	0.99933	0.96327	3.84658
1956	56.5	0.00067	0.99933	0.96262	2.88396
1955	57.5	0.00067	0.99933	0.96197	1.92199
1954	58.5	0.00067	0.99933	0.96132	0.96067

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Burns & McDonnell SINCE 1898

Production Boiler Plant Account: 312

Date of Retirement (Mid Year):	2038
Interim Retirement Rate:	0.00373
Study Date, Year-End:	2012
Future Life from Study Date:	26.3
Remaining Life (F/E + .5) =	26.1

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Removal Costs	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	3,916,288	0	29,615	$ 3,945,902	0.00000
1966	0	0	0	$ 3,945,902	0.00000
1967	0	0	0	$ 3,945,902	0.00000
1968	0	0	0	$ 3,945,902	0.00000
1969	7,858,376	6,000	190,953	$ 11,989,231	0.00050
1970	6,220,732	5,360	293,878	$ 18,498,481	0.00029
1971	9,980,100	0	159,041	$ 28,637,622	0.00000
1972	182,490	35,260	1,019	$ 28,785,871	0.00122
1973	84,361	47,785	0	$ 28,822,448	0.00166
1974	135,999	980	0	$ 28,957,466	0.00003
1975	40,000	72,300	0	$ 28,925,167	0.00250
1976	7,336	807	771	$ 28,932,467	0.00003
1977	1,095,499	193,134	0	$ 29,834,832	0.00647
1978	477,024	18,000	0	$ 30,293,856	0.00059
1979	66,406,550	2,559	23,021	$ 96,720,868	0.00003
1980	2,717,381	325,053	2,119	$ 99,115,315	0.00328
1981	67,373,001	41,201	235,173	$ 166,682,289	0.00025
1982	739,077	234,532	5,315	$ 167,192,149	0.00140
1983	1,102,532	110,071	3,604	$ 168,188,215	0.00065
1984	3,424,227	713,794	5,987	$ 170,904,636	0.00418
1985	566,092	345,044	700	$ 171,126,384	0.00202
1986	384,348,232	44,591	5,994	$ 555,436,019	0.00008
1987	776,001	449,385	11,952	$ 555,774,587	0.00081
1988	280,438	163,385	5,342	$ 555,896,982	0.00029
1989	1,396,615	853,365	360	$ 556,440,592	0.00153
1990	2,154,435	729,927	113	$ 557,865,213	0.00131
1991	839,541	430,079	160	$ 558,274,835	0.00077
1992	2,194,697	771,819	0	$ 559,697,713	0.00138
1993	170,138	2,547,906	0	$ 557,319,945	0.00457
1994	1,084,716	953,892	0	$ 557,450,769	0.00171
1995	914,144	455,049	0	$ 557,909,864	0.00082
1996	255,860	118,764	0	$ 558,046,960	0.00021
1997	427,596	1,098,445	0	$ 557,376,111	0.00197
1998	1,219,719	6,723,594	0	$ 551,872,236	0.01218
1999	2,031,435	2,387,306	0	$ 551,516,365	0.00433
2000	10,112,631	1,740,646	0	$ 559,888,350	0.00311
2001	9,846,079	4,009,239	0	$ 565,725,190	0.00709
2002	4,734,655	2,524,814	0	$ 567,935,031	0.00445
2003	7,219,552	6,319,165	0	$ 568,835,419	0.01111
2004	7,970,539	1,256,416	0	$ 575,549,541	0.00218
2005	7,816,847	1,901,318	0	$ 581,465,070	0.00327
2006	7,689,092	1,890,342	0	$ 587,263,821	0.00322
2007	11,599,504	986,959	0	$ 597,876,366	0.00165
2008	10,508,691	3,467,092	0	$ 604,917,965	0.00573
2009	22,475,295	1,987,827	0	$ 625,405,433	0.00318
2010	15,467,001	14,872,092	1,135,983	$ 627,136,325	0.02371
2011	10,984,838	1,997,775	596,660	$ 636,720,048	0.00314
TOTAL	$ 696,845,360	$ 62,833,072	$ 2,707,760	$ 16,845,707,703	0.00373

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0.5	0.00373	0.99627	0.99814	25.58682
2011	1.5	0.00373	0.99627	0.99441	25.49138
2010	2.5	0.00373	0.99627	0.99070	25.39630
2009	3.5	0.00373	0.99627	0.98701	25.30157
2008	4.5	0.00373	0.99627	0.98333	25.20720
2007	5.5	0.00373	0.99627	0.97966	25.11318
2006	6.5	0.00373	0.99627	0.97600	25.01951
2005	7.5	0.00373	0.99627	0.97236	24.92619
2004	8.5	0.00373	0.99627	0.96874	24.83322
2003	9.5	0.00373	0.99627	0.96512	24.74059
2002	10.5	0.00373	0.99627	0.96152	24.64831
2001	11.5	0.00373	0.99627	0.95794	24.55637
2000	12.5	0.00373	0.99627	0.95436	24.46478
1999	13.5	0.00373	0.99627	0.95081	24.37353
1998	14.5	0.00373	0.99627	0.94726	24.28262
1997	15.5	0.00373	0.99627	0.94373	24.19205
1996	16.5	0.00373	0.99627	0.94021	24.10181
1995	17.5	0.00373	0.99627	0.93670	24.01191
1994	18.5	0.00373	0.99627	0.93320	23.92235
1993	19.5	0.00373	0.99627	0.92972	23.83312
1992	20.5	0.00373	0.99627	0.92626	23.74423
1991	21.5	0.00373	0.99627	0.92280	23.65566
1990	22.5	0.00373	0.99627	0.91936	23.56743
1989	23.5	0.00373	0.99627	0.91593	23.47953
1988	24.5	0.00373	0.99627	0.91251	23.39195
1987	25.5	0.00373	0.99627	0.90911	23.30470
1986	26.5	0.00373	0.99627	0.90572	23.21777
1985	27.5	0.00373	0.99627	0.90234	23.13117
1984	28.5	0.00373	0.99627	0.89898	23.04490
1983	29.5	0.00373	0.99627	0.89562	22.95894
1982	30.5	0.00373	0.99627	0.89228	22.87331
1981	31.5	0.00373	0.99627	0.88895	22.78799
1980	32.5	0.00373	0.99627	0.88564	22.70299
1979	33.5	0.00373	0.99627	0.88233	21.82066
1978	34.5	0.00373	0.99627	0.87904	20.94162
1977	35.5	0.00373	0.99627	0.87576	20.06585
1976	36.5	0.00373	0.99627	0.87250	19.19335
1975	37.5	0.00373	0.99627	0.86924	18.32411
1974	38.5	0.00373	0.99627	0.86600	17.45811
1973	39.5	0.00373	0.99627	0.86277	16.59534
1972	40.5	0.00373	0.99627	0.85955	15.73578
1971	41.5	0.00373	0.99627	0.85635	14.87944
1970	42.5	0.00373	0.99627	0.85315	14.02628
1969	43.5	0.00373	0.99627	0.84997	13.17631
1968	44.5	0.00373	0.99627	0.84680	12.32951
1967	45.5	0.00373	0.99627	0.84364	11.48587
1966	46.5	0.00373	0.99627	0.84050	10.64537
1965	47.5	0.00373	0.99627	0.83736	9.80801
1964	48.5	0.00373	0.99627	0.83424	8.97377
1963	49.5	0.00373	0.99627	0.83113	8.14265
1962	50.5	0.00373	0.99627	0.82803	7.31462
1961	51.5	0.00373	0.99627	0.82494	6.48969
1960	52.5	0.00373	0.99627	0.82186	5.66783
1959	53.5	0.00373	0.99627	0.81879	4.84903
1958	54.5	0.00373	0.99627	0.81574	4.03329
1957	55.5	0.00373	0.99627	0.81270	3.22059
1956	56.5	0.00373	0.99627	0.80967	2.41093
1955	57.5	0.00373	0.99627	0.80665	1.60428
1954	58.5	0.00373	0.99627	0.80364	0.80064

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Burns & McDonnell SINCE 1898

Production Boiler Plant Env Comp *Account:* 312 A-K

Date of Retirement (Mid Year):	2038
Interim Retirement Rate:	0.00252
Study Date. Year-End:	2012
Future Life from Study Date:	26.3
Remaining Life (F/E + 5) =	26.6

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Removal Costs	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	44,570	0	0	$ 44,570	0.00000
1966	0	0	0	$ 44,570	0.00000
1967	0	0	0	$ 44,570	0.00000
1968	0	0	0	$ 44,570	0.00000
1969	700,874	0	0	$ 745,444	0.00000
1970	771,874	0	0	$ 1,517,318	0.00000
1971	528,902	0	0	$ 2,046,220	0.00000
1972	1,374	0	0	$ 2,047,595	0.00000
1973	380,587	0	0	$ 2,428,182	0.00000
1974	0	0	0	$ 2,428,182	0.00000
1975	52,494	0	0	$ 2,480,676	0.00000
1976	0	0	0	$ 2,480,676	0.00000
1977	216,624	0	0	$ 2,697,300	0.00000
1978	93,337	0	0	$ 2,790,637	0.00000
1979	38,873,298	0	0	$ 41,663,935	0.00000
1980	3,378,499	0	0	$ 45,042,434	0.00000
1981	35,350,822	0	0	$ 80,393,255	0.00000
1982	247,347	0	0	$ 80,640,603	0.00000
1983	1,374,682	0	0	$ 82,015,285	0.00000
1984	660,393	0	0	$ 82,675,677	0.00000
1985	243,512	0	0	$ 82,919,189	0.00000
1986	187,168,630	0	0	$ 270,087,820	0.00000
1987	69,775	0	0	$ 270,157,594	0.00000
1988	68,549	0	0	$ 270,226,143	0.00000
1989	19,814	0	0	$ 270,245,958	0.00000
1990	1,075,429	0	0	$ 271,321,387	0.00000
1991	349,038	0	0	$ 271,670,425	0.00000
1992	79,882	0	0	$ 271,750,307	0.00000
1993	4,899,560	0	0	$ 276,649,866	0.00000
1994	895,543	81,250	0	$ 277,464,159	0.00029
1995	37,056,711	1,122,550	0	$ 313,398,320	0.00358
1996	3,656,557	894,795	0	$ 316,160,082	0.00283
1997	1,778,459	449,630	0	$ 317,488,911	0.00142
1998	263,573	714,153	0	$ 317,038,331	0.00225
1999	1,331,517	873,952	0	$ 317,495,895	0.00275
2000	497,198	351,164	0	$ 317,641,930	0.00111
2001	2,817,186	261,585	0	$ 320,197,531	0.00082
2002	1,582,029	295,920	0	$ 321,483,640	0.00092
2003	80,152,968	934,849	0	$ 400,701,758	0.00233
2004	53,198,911	2,021,299	0	$ 451,879,370	0.00447
2005	1,915,969	1,337,010	0	$ 452,458,330	0.00295
2006	1,038,027	270,526	0	$ 453,225,830	0.00060
2007	4,462,599	1,300,047	0	$ 456,388,381	0.00285
2008	3,268,623	1,044,842	0	$ 458,612,162	0.00228
2009	104,277,773	1,902,711	0	$ 560,987,224	0.00339
2010	18,639,616	9,988,610	5,328,308	$ 574,966,538	0.01737
2011	6,637,202	2,584,868	942,428	$ 579,961,300	0.00446
TOTAL	$ 618,759,941	$ 26,429,761	$ 6,270,736	$ 10,495,450,994	0.00252

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0.5	0.00252	0.99748	0.99874	26.03574
2011	1.5	0.00252	0.99748	0.99623	25.97018
2010	2.5	0.00252	0.99748	0.99372	25.90478
2009	3.5	0.00252	0.99748	0.99121	25.83955
2008	4.5	0.00252	0.99748	0.98872	25.77448
2007	5.5	0.00252	0.99748	0.98623	25.70957
2006	6.5	0.00252	0.99748	0.98375	25.64483
2005	7.5	0.00252	0.99748	0.98127	25.58025
2004	8.5	0.00252	0.99748	0.97880	25.51584
2003	9.5	0.00252	0.99748	0.97633	25.45158
2002	10.5	0.00252	0.99748	0.97387	25.38749
2001	11.5	0.00252	0.99748	0.97142	25.32356
2000	12.5	0.00252	0.99748	0.96897	25.25979
1999	13.5	0.00252	0.99748	0.96653	25.19618
1998	14.5	0.00252	0.99748	0.96410	25.13273
1997	15.5	0.00252	0.99748	0.96167	25.06944
1996	16.5	0.00252	0.99748	0.95925	25.00631
1995	17.5	0.00252	0.99748	0.95684	24.94334
1994	18.5	0.00252	0.99748	0.95443	24.88053
1993	19.5	0.00252	0.99748	0.95202	24.81787
1992	20.5	0.00252	0.99748	0.94963	24.75538
1991	21.5	0.00252	0.99748	0.94723	24.69304
1990	22.5	0.00252	0.99748	0.94485	24.63085
1989	23.5	0.00252	0.99748	0.94247	24.56883
1988	24.5	0.00252	0.99748	0.94010	24.50696
1987	25.5	0.00252	0.99748	0.93773	24.44524
1986	26.5	0.00252	0.99748	0.93537	24.38369
1985	27.5	0.00252	0.99748	0.93301	24.32228
1984	28.5	0.00252	0.99748	0.93066	24.26103
1983	29.5	0.00252	0.99748	0.92832	24.19994
1982	30.5	0.00252	0.99748	0.92598	24.13900
1981	31.5	0.00252	0.99748	0.92365	24.07821
1980	32.5	0.00252	0.99748	0.92132	24.01758
1979	33.5	0.00252	0.99748	0.91900	23.09858
1978	34.5	0.00252	0.99748	0.91669	22.18189
1977	35.5	0.00252	0.99748	0.91438	21.26751
1976	36.5	0.00252	0.99748	0.91208	20.35543
1975	37.5	0.00252	0.99748	0.90978	19.44565
1974	38.5	0.00252	0.99748	0.90749	18.53816
1973	39.5	0.00252	0.99748	0.90520	17.63295
1972	40.5	0.00252	0.99748	0.90293	16.73003
1971	41.5	0.00252	0.99748	0.90065	15.82937
1970	42.5	0.00252	0.99748	0.89838	14.93099
1969	43.5	0.00252	0.99748	0.89612	14.03487
1968	44.5	0.00252	0.99748	0.89386	13.14101
1967	45.5	0.00252	0.99748	0.89161	12.24939
1966	46.5	0.00252	0.99748	0.88937	11.36002
1965	47.5	0.00252	0.99748	0.88713	10.47289
1964	48.5	0.00252	0.99748	0.88489	9.58800
1963	49.5	0.00252	0.99748	0.88267	8.70533
1962	50.5	0.00252	0.99748	0.88044	7.82489
1961	51.5	0.00252	0.99748	0.87823	6.94666
1960	52.5	0.00252	0.99748	0.87602	6.07065
1959	53.5	0.00252	0.99748	0.87381	5.19684
1958	54.5	0.00252	0.99748	0.87161	4.32523
1957	55.5	0.00252	0.99748	0.86941	3.45582
1956	56.5	0.00252	0.99748	0.86722	2.58859
1955	57.5	0.00252	0.99748	0.86504	1.72355
1954	58.5	0.00252	0.99748	0.86286	0.86069

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Production Short-Life Production Plant -Envi   Account: PROD 312 L-P

Date of Retirement (Mid Year):	2017
Interim Retirement Rate:	0.12252
Study Date, Year-End:	2012
Future Life from Study Date:	5.0
Remaining Life (F/E + .5) =	4.8

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Removal Costs	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	0	0	0	$ -	0.00000
1966	0	0	0	$ -	0.00000
1967	0	0	0	$ -	0.00000
1968	0	0	0	$ -	0.00000
1969	0	0	0	$ -	0.00000
1970	0	0	0	$ -	0.00000
1971	0	0	0	$ -	0.00000
1972	0	0	0	$ -	0.00000
1973	0	0	0	$ -	0.00000
1974	0	0	0	$ -	0.00000
1975	0	0	0	$ -	0.00000
1976	0	0	0	$ -	0.00000
1977	0	0	0	$ -	0.00000
1978	0	0	0	$ -	0.00000
1979	0	0	0	$ -	0.00000
1980	0	0	0	$ -	0.00000
1981	0	0	0	$ -	0.00000
1982	0	0	0	$ -	0.00000
1983	0	0	0	$ -	0.00000
1984	0	0	0	$ -	0.00000
1985	0	0	0	$ -	0.00000
1986	0	0	0	$ -	0.00000
1987	0	0	0	$ -	0.00000
1988	0	0	0	$ -	0.00000
1989	0	0	0	$ -	0.00000
1990	0	0	0	$ -	0.00000
1991	0	0	0	$ -	0.00000
1992	0	0	0	$ -	0.00000
1993	0	0	0	$ -	0.00000
1994	0	0	0	$ -	0.00000
1995	0	0	0	$ -	0.00000
1996	0	0	0	$ -	0.00000
1997	0	0	0	$ -	0.00000
1998	0	0	0	$ -	0.00000
1999	0	0	0	$ -	0.00000
2000	0	0	0	$ -	0.00000
2001	0	0	0	$ -	0.00000
2002	185,953	0	0	$ 185,953	0.00000
2003	394,231	0	0	$ 580,184	0.00000
2004	0	44,130	0	$ 536,054	0.08232
2005	246,373	124,232	0	$ 658,195	0.18875
2006	0	0	0	$ 658,195	0.00000
2007	413,100	414,060	0	$ 657,235	0.63000
2008	0	137,386	0	$ 519,849	0.26428
2009	0	0	0	$ 519,849	0.00000
2010	0	0	0	$ 519,849	0.00000
2011	0	0	0	$ 519,849	0.00000
TOTAL	$ 1,239,656	$ 719,807	$ -	$ 5,875,060	0.12252

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0.5	0.12252	0.87748	0.93874	4.03021
2011	1.5	0.12252	0.87748	0.82373	3.53643
2010	2.5	0.12252	0.87748	0.72280	3.10315
2009	3.5	0.12252	0.87748	0.63425	2.72296
2008	4.5	0.12252	0.87748	0.55654	2.38934
2007	5.5	0.12252	0.87748	0.48835	2.09660
2006	6.5	0.12252	0.87748	0.42852	1.83973
2005	7.5	0.12252	0.87748	0.37602	1.61433
2004	8.5	0.12252	0.87748	0.32995	1.41654
2003	9.5	0.12252	0.87748	0.28952	1.24299
2002	10.5	0.12252	0.87748	0.25405	1.09070
2001	11.5	0.12252	0.87748	0.22293	0.95707
2000	12.5	0.12252	0.87748	0.19561	0.83981
1999	13.5	0.12252	0.87748	0.17165	0.73691
1998	14.5	0.12252	0.87748	0.15062	0.64663
1997	15.5	0.12252	0.87748	0.13216	0.56740
1996	16.5	0.12252	0.87748	0.11597	0.49789
1995	17.5	0.12252	0.87748	0.10176	0.43689
1994	18.5	0.12252	0.87748	0.08929	0.38336
1993	19.5	0.12252	0.87748	0.07835	0.33639
1992	20.5	0.12252	0.87748	0.06875	0.29518
1991	21.5	0.12252	0.87748	0.06033	0.25901
1990	22.5	0.12252	0.87748	0.05294	0.22728
1989	23.5	0.12252	0.87748	0.04645	0.19943
1988	24.5	0.12252	0.87748	0.04076	0.17500
1987	25.5	0.12252	0.87748	0.03577	0.15356
1986	26.5	0.12252	0.87748	0.03139	0.13474
1985	27.5	0.12252	0.87748	0.02754	0.11823
1984	28.5	0.12252	0.87748	0.02417	0.10375
1983	29.5	0.12252	0.87748	0.02120	0.09104
1982	30.5	0.12252	0.87748	0.01861	0.07988
1981	31.5	0.12252	0.87748	0.01633	0.07010
1980	32.5	0.12252	0.87748	0.01433	0.06151
1979	33.5	0.12252	0.87748	0.01257	0.05397
1978	34.5	0.12252	0.87748	0.01103	0.04736
1977	35.5	0.12252	0.87748	0.00968	0.04156
1976	36.5	0.12252	0.87748	0.00849	0.03647
1975	37.5	0.12252	0.87748	0.00745	0.03200
1974	38.5	0.12252	0.87748	0.00654	0.02808
1973	39.5	0.12252	0.87748	0.00574	0.02464
1972	40.5	0.12252	0.87748	0.00504	0.02162
1971	41.5	0.12252	0.87748	0.00442	0.01897
1970	42.5	0.12252	0.87748	0.00388	0.01665
1969	43.5	0.12252	0.87748	0.00340	0.01461
1968	44.5	0.12252	0.87748	0.00299	0.01282
1967	45.5	0.12252	0.87748	0.00262	0.01125
1966	46.5	0.12252	0.87748	0.00230	0.00987
1965	47.5	0.12252	0.87748	0.00202	0.00866
1964	48.5	0.12252	0.87748	0.00177	0.00760
1963	49.5	0.12252	0.87748	0.00155	0.00667
1962	50.5	0.12252	0.87748	0.00136	0.00585
1961	51.5	0.12252	0.87748	0.00120	0.00513
1960	52.5	0.12252	0.87748	0.00105	0.00450
1959	53.5	0.12252	0.87748	0.00092	0.00358
1958	54.5	0.12252	0.87748	0.00081	0.00278
1957	55.5	0.12252	0.87748	0.00071	0.00207
1956	56.5	0.12252	0.87748	0.00062	0.00145
1955	57.5	0.12252	0.87748	0.00055	0.00090
1954	58.5	0.12252	0.87748	0.00048	0.00042

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Burns & McDonnell SINCE 1898

Production Short-Life Production Plant -Oth Account: PROD 312 V-Z

Date of Retirement (Mid Year):	2017
Interim Retirement Rate:	0.04135
Study Date, Year-End:	2012
Future Life from Study Date:	5.0
Remaining Life (F/E + .5) =	4.9

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Removal Costs	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	0	0	0	$ -	0.00000
1966	0	0	0	$ -	0.00000
1967	0	0	0	$ -	0.00000
1968	0	0	0	$ -	0.00000
1969	0	0	0	$ -	0.00000
1970	0	0	0	$ -	0.00000
1971	0	0	0	$ -	0.00000
1972	0	0	0	$ -	0.00000
1973	0	0	0	$ -	0.00000
1974	0	0	0	$ -	0.00000
1975	102,791	0	0	$ 102,791	0.00000
1976	0	0	0	$ 102,791	0.00000
1977	81,320	0	0	$ 184,111	0.00000
1978	0	0	0	$ 184,111	0.00000
1979	0	0	0	$ 184,111	0.00000
1980	0	0	0	$ 184,111	0.00000
1981	0	0	0	$ 184,111	0.00000
1982	0	0	0	$ 184,111	0.00000
1983	0	0	0	$ 184,111	0.00000
1984	0	0	0	$ 184,111	0.00000
1985	0	0	0	$ 184,111	0.00000
1986	0	0	0	$ 184,111	0.00000
1987	0	0	0	$ 184,111	0.00000
1988	0	0	0	$ 184,111	0.00000
1989	0	0	0	$ 184,111	0.00000
1990	0	0	0	$ 184,111	0.00000
1991	0	0	0	$ 184,111	0.00000
1992	0	0	0	$ 184,111	0.00000
1993	0	0	0	$ 184,111	0.00000
1994	0	0	0	$ 184,111	0.00000
1995	0	0	0	$ 184,111	0.00000
1996	0	0	0	$ 184,111	0.00000
1997	0	0	0	$ 184,111	0.00000
1998	0	0	0	$ 184,111	0.00000
1999	0	46,482	0	$ 137,628	0.33774
2000	0	0	0	$ 137,628	0.00000
2001	29,494	0	0	$ 167,122	0.00000
2002	0	0	0	$ 167,122	0.00000
2003	0	0	0	$ 167,122	0.00000
2004	135,678	0	0	$ 302,801	0.00000
2005	0	0	0	$ 302,801	0.00000
2006	195,609	29,494	0	$ 468,916	0.06290
2007	128,037	54,814	0	$ 542,138	0.10111
2008	132,958	0	0	$ 675,096	0.00000
2009	62,867	0	0	$ 737,963	0.00000
2010	0	0	0	$ 737,963	0.00000
2011	354,011	299,569	11,683	$ 804,088	0.37256
TOTAL	$ 1,222,766	$ 430,361	$ 11,683	$ 10,408,496	0.04135

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0.5	0.04135	0.95865	0.97933	4.32171
2011	1.5	0.04135	0.95865	0.93883	4.14302
2010	2.5	0.04135	0.95865	0.90002	3.97172
2009	3.5	0.04135	0.95865	0.86280	3.80750
2008	4.5	0.04135	0.95865	0.82713	3.65007
2007	5.5	0.04135	0.95865	0.79293	3.49915
2006	6.5	0.04135	0.95865	0.76014	3.35447
2005	7.5	0.04135	0.95865	0.72871	3.21578
2004	8.5	0.04135	0.95865	0.69858	3.08281
2003	9.5	0.04135	0.95865	0.66970	2.95535
2002	10.5	0.04135	0.95865	0.64201	2.83315
2001	11.5	0.04135	0.95865	0.61546	2.71601
2000	12.5	0.04135	0.95865	0.59002	2.60371
1999	13.5	0.04135	0.95865	0.56562	2.49606
1998	14.5	0.04135	0.95865	0.54223	2.39285
1997	15.5	0.04135	0.95865	0.51981	2.29391
1996	16.5	0.04135	0.95865	0.49832	2.19907
1995	17.5	0.04135	0.95865	0.47772	2.10814
1994	18.5	0.04135	0.95865	0.45797	2.02098
1993	19.5	0.04135	0.95865	0.43903	1.93741
1992	20.5	0.04135	0.95865	0.42088	1.85731
1991	21.5	0.04135	0.95865	0.40348	1.78051
1990	22.5	0.04135	0.95865	0.38679	1.70690
1989	23.5	0.04135	0.95865	0.37080	1.63632
1988	24.5	0.04135	0.95865	0.35547	1.56866
1987	25.5	0.04135	0.95865	0.34077	1.50380
1986	26.5	0.04135	0.95865	0.32668	1.44163
1985	27.5	0.04135	0.95865	0.31317	1.38202
1984	28.5	0.04135	0.95865	0.30023	1.32488
1983	29.5	0.04135	0.95865	0.28781	1.27010
1982	30.5	0.04135	0.95865	0.27591	1.21758
1981	31.5	0.04135	0.95865	0.26450	1.16724
1980	32.5	0.04135	0.95865	0.25357	1.11898
1979	33.5	0.04135	0.95865	0.24308	1.07271
1978	34.5	0.04135	0.95865	0.23303	1.02836
1977	35.5	0.04135	0.95865	0.22340	0.98584
1976	36.5	0.04135	0.95865	0.21416	0.94508
1975	37.5	0.04135	0.95865	0.20531	0.90600
1974	38.5	0.04135	0.95865	0.19682	0.86854
1973	39.5	0.04135	0.95865	0.18868	0.83263
1972	40.5	0.04135	0.95865	0.18088	0.79820
1971	41.5	0.04135	0.95865	0.17340	0.76520
1970	42.5	0.04135	0.95865	0.16623	0.73356
1969	43.5	0.04135	0.95865	0.15936	0.70323
1968	44.5	0.04135	0.95865	0.15277	0.67415
1967	45.5	0.04135	0.95865	0.14645	0.64628
1966	46.5	0.04135	0.95865	0.14040	0.61956
1965	47.5	0.04135	0.95865	0.13459	0.59394
1964	48.5	0.04135	0.95865	0.12903	0.56938
1963	49.5	0.04135	0.95865	0.12369	0.54584
1962	50.5	0.04135	0.95865	0.11858	0.52327
1961	51.5	0.04135	0.95865	0.11367	0.50164
1960	52.5	0.04135	0.95865	0.10897	0.48089
1959	53.5	0.04135	0.95865	0.10447	0.46101
1958	54.5	0.04135	0.95865	0.10015	0.44195
1957	55.5	0.04135	0.95865	0.09601	0.34594
1956	56.5	0.04135	0.95865	0.09204	0.25390
1955	57.5	0.04135	0.95865	0.08823	0.16567
1954	58.5	0.04135	0.95865	0.08458	0.08109

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Burns & McDonnell SINCE 1898

Production Turbine | Account: 314

Date of Retirement (Mid Year):	2038
Interim Retirement Rate:	0 00261
Study Date, Year-End:	2012
Future Life from Study Date:	26 3
Remaining Life (F/E + .5) =	26.5

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Removal Costs	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0 00000
1954	0	0	0	$ -	0 00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0 00000
1957	0	0	0	$ -	0 00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0 00000
1960	0	0	0	$ -	0 00000
1961	0	0	0	$ -	0 00000
1962	0	0	0	$ -	0 00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	2.796,515	0	31,664	$ 2.828,179	0 00000
1966	0	0	0	$ 2.828,179	0.00000
1967	0	0	0	$ 2.828.179	0 00000
1968	0	0	0	$ 2.828,179	0 00000
1969	5,207,206	0	1,908	$ 8,037,293	0.00000
1970	5.109.447	0	111,046	$ 13,257,786	0.00000
1971	5.592,461	0	2,874	$ 18,853,121	0.00000
1972	1,342	0	0	$ 18,854,463	0.00000
1973	0	0	0	$ 18,854,463	0 00000
1974	4,504	0	0	$ 18,858,967	0 00000
1975	0	0	0	$ 18,858,967	0.00000
1976	2,333	0	28	$ 18,861,329	0 00000
1977	57,374	2,004	0	$ 18,916,698	0.00011
1978	11,010	1.844	0	$ 18,925,864	0.00010
1979	23,074,937	0	3.445	$ 42,004,246	0 00000
1980	7,990	0	0	$ 42,012,236	0.00000
1981	27,432,065	0	78.282	$ 69,522,583	0 00000
1982	26,800	0	0	$ 69,549.383	0 00000
1983	83,586	0	50	$ 69.633,019	0.00000
1984	499,185	69.117	341	$ 70,063,429	0 00099
1985	29,881	0	0	$ 70.093,310	0 00000
1986	122,282,418	0	100	$ 192,375,827	0.00000
1987	17,819	5,500	0	$ 192,388,146	0 00003
1988	429,682	0	0	$ 192.817.829	0.00000
1989	1,168,803	293,352	0	$ 193,693,279	0 00151
1990	37,733	0	0	$ 193.731.012	0 00000
1991	486,727	4,957	0	$ 194,212.781	0 00003
1992	3,121,487	1,124,186	0	$ 196,210,082	0 00573
1993	1,495,730	914,753	0	$ 196.791.060	0.00465
1994	294,144	8,633	0	$ 197,076,571	0 00004
1995	182,041	139,494	0	$ 197,119.119	0 00071
1996	0	0	0	$ 197,119,119	0 00000
1997	33,629	82,124	0	$ 197,070,624	0 00042
1998	41,614	100.106	0	$ 197,012 132	0 00051
1999	1,685,960	35	0	$ 198,698,057	0 00000
2000	336,847	626,847	0	$ 198.408,056	0.00316
2001	2.732,008	650,720	0	$ 200.489,344	0 00325
2002	1.777,170	2,332,032	0	$ 199.934,481	0 01166
2003	3.470,385	1,128,858	0	$ 202,276,009	0 00558
2004	2,901.597	566,547	0	$ 204,611.058	0 00277
2005	2,306,239	715,673	0	$ 206,201,624	0.00347
2006	698,755	202.380	0	$ 206.697,999	0.00098
2007	2.963,416	823,013	0	$ 208,838,403	0 00394
2008	1,940,927	1,296,832	0	$ 209.482,498	0.00619
2009	5,760,515	1.115,416	0	$ 214,127.597	0 00521
2010	4.005,723	1,827.596	147.931	$ 216,453,656	0 00844
2011	3,821,813	1,758,893	105.554	$ 218.622.130	0 00805
TOTAL	$ 233,929,818	$ 15,790,914	$ 483,226	$ 6,057,550,500	0.00261

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0 5	0 00261	0.99739	0 99870	26 00259
2011	1 5	0.00261	0 99739	0.99609	25.93481
2010	2 5	0.00261	0.99739	0 99350	25 86720
2009	3.5	0 00261	0 99739	0 99091	25 79977
2008	4.5	0.00261	0 99739	0.98832	25.73251
2007	5.5	0 00261	0.99739	0.98575	25.66543
2006	6 5	0.00261	0.99739	0.98318	25.59853
2005	7.5	0.00261	0.99739	0.98061	25.53180
2004	8 5	0 00261	0 99739	0.97806	25.46524
2003	9.5	0.00261	0.99739	0 97551	25.39886
2002	10 5	0 00261	0 99739	0.97297	25.33265
2001	11.5	0.00261	0.99739	0.97043	25.26661
2000	12 5	0 00261	0.99739	0 96790	25.20075
1999	13 5	0.00261	0.99739	0.96538	25.13505
1998	14.5	0.00261	0 99739	0 96286	25.06953
1997	15.5	0.00261	0.99739	0.96035	25.00418
1996	16.5	0.00261	0.99739	0.95785	24 93900
1995	17.5	0 00261	0.99739	0.95535	24.87399
1994	18 5	0.00261	0 99739	0 95286	24.80914
1993	19.5	0.00261	0 99739	0.95038	24.74447
1992	20 5	0.00261	0 99739	0.94780	24 67997
1991	21.5	0 00261	0 99739	0 94543	24.61563
1990	22.5	0.00261	0.99739	0.94296	24 55146
1989	23 5	0 00261	0 99739	0 94050	24.48746
1988	24.5	0.00261	0 99739	0 93805	24 42363
1987	25.5	0 00261	0 99739	0 93561	24.35996
1986	26.5	0 00261	0.99739	0.93317	24.29646
1985	27 5	0.00261	0.99739	0 93074	24.23312
1984	28 5	0.00261	0.99739	0.92831	24.16995
1983	29.5	0 00261	0 99739	0 92589	24.10694
1982	30 5	0.00261	0 99739	0.92348	24.04410
1981	31.5	0.00261	0 99739	0 92107	23.98142
1980	32 5	0.00261	0.99739	0.91867	23.91891
1979	33.5	0 00261	0 99739	0.91627	23.00263
1978	34.5	0.00261	0 99739	0 91388	22 08875
1977	35 5	0.00261	0.99739	0 91150	21.17725
1976	36 5	0.00261	0.99739	0 90913	20.26812
1975	37.5	0 00261	0.99739	0 90676	19.36137
1974	38 5	0 00261	0.99739	0.90439	18.45698
1973	39.5	0 00261	0.99739	0.90203	17.55494
1972	40 5	0.00261	0 99739	0.89968	16.65526
1971	41.5	0.00261	0.99739	0.89734	15.75792
1970	42 5	0.00261	0.99739	0.89500	14.86292
1969	43.5	0.00261	0 99739	0.89267	13.97026
1968	44 5	0.00261	0.99739	0 89034	13.07992
1967	45 5	0.00261	0 99739	0.88802	12 19190
1966	46.5	0.00261	0 99739	0 88570	11.30620
1965	47 5	0.00261	0.99739	0.88339	10.42281
1964	48.5	0.00261	0 99739	0.88109	9 54172
1963	49 5	0 00261	0 99739	0.87879	8.66292
1962	50.5	0.00261	0.99739	0 87650	7 78642
1961	51.5	0 00261	0.99739	0.87422	6 91220
1960	52.5	0.00261	0.99739	0 87194	6.04026
1959	53.5	0.00261	0 99739	0.86967	5 17060
1958	54.5	0.00261	0.99739	0.86740	4.30320
1957	55 5	0.00261	0 99739	0.86514	3 43806
1956	56.5	0.00261	0.99739	0.86288	2.57518
1955	57.5	0.00261	0.99739	0.86063	1 71454
1954	58 5	0.00261	0 99739	0.85839	0.85615

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Burns & McDonnell SINCE 1898

Production Electric Eqpt	Account:	315	
Date of Retirement (Mid Year):		2030	
Interim Retirement Rate:		0.00117	
Study Date, Year-End:		2012	
Future Life from Study Date:		17.7	
Remaining Life (F/E + .5) =		18.3	

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Removal Costs	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	806,672	0	4,197	$ 810,870	0.00000
1966	0	0	0	$ 810,870	0.00000
1967	0	0	0	$ 810,870	0.00000
1968	0	0	0	$ 810,870	0.00000
1969	1,657,054	0	429	$ 2,468,352	0.00000
1970	1,211,816	0	0	$ 3,680,168	0.00000
1971	2,214,896	0	0	$ 5,895,063	0.00000
1972	0	0	0	$ 5,895,063	0.00000
1973	0	0	0	$ 5,895,063	0.00000
1974	563	0	0	$ 5,895,627	0.00000
1975	1,109	1,104	0	$ 5,895,632	0.00019
1976	638	0	0	$ 5,896,270	0.00000
1977	9,764	0	0	$ 5,906,034	0.00000
1978	51,819	0	0	$ 5,957,853	0.00000
1979	8,001,493	0	0	$ 13,959,346	0.00000
1980	1,282	0	0	$ 13,960,628	0.00000
1981	7,135,784	0	4,685	$ 21,101,097	0.00000
1982	124,942	0	0	$ 21,226,039	0.00000
1983	35,591	119,116	0	$ 21,142,514	0.00563
1984	372,343	393,929	0	$ 21,120,928	0.01865
1985	0	0	0	$ 21,120,928	0.00000
1986	33,607,081	1,604	0	$ 54,726,405	0.00003
1987	2,963	11,228	872	$ 54,719,012	0.00021
1988	50,734	24,761	821	$ 54,745,806	0.00045
1989	12,496	2,515	0	$ 54,755,788	0.00005
1990	0	0	0	$ 54,755,788	0.00000
1991	26,492	0	0	$ 54,782,280	0.00000
1992	0	8,694	0	$ 54,773,586	0.00016
1993	0	758	0	$ 54,772,828	0.00001
1994	39,463	17,049	0	$ 54,795,241	0.00031
1995	13,012	0	0	$ 54,808,253	0.00000
1996	0	15,661	0	$ 54,792,592	0.00029
1997	0	0	0	$ 54,792,592	0.00000
1998	11,822	0	0	$ 54,804,414	0.00000
1999	0	0	0	$ 54,804,414	0.00000
2000	14,681	13,170	0	$ 54,805,925	0.00024
2001	144,537	77,933	0	$ 54,872,529	0.00142
2002	72,066	17,065	0	$ 54,927,530	0.00031
2003	64,918	37,206	0	$ 54,955,242	0.00068
2004	765,626	81,116	0	$ 55,639,752	0.00146
2005	539,116	142,019	0	$ 56,036,850	0.00253
2006	979,575	259,551	0	$ 56,756,874	0.00457
2007	569,965	166,701	0	$ 57,160,138	0.00292
2008	949,772	265,189	0	$ 57,644,721	0.00458
2009	885,908	38,946	0	$ 58,691,681	0.00066
2010	1,196,210	148,255	55,000	$ 59,794,636	0.00248
2011	362,044	145,755	19,013	$ 60,029,938	0.00243
TOTAL	$ 61,934,249	$ 1,989,328	$ 85,017	$ 1,698,634,835	0.00117

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0.5	0.00117	0.99883	0.99941	17.79064
2011	1.5	0.00117	0.99883	0.99824	17.76980
2010	2.5	0.00117	0.99883	0.99707	17.74899
2009	3.5	0.00117	0.99883	0.99591	17.72820
2008	4.5	0.00117	0.99883	0.99474	17.70744
2007	5.5	0.00117	0.99883	0.99358	17.68670
2006	6.5	0.00117	0.99883	0.99241	17.66599
2005	7.5	0.00117	0.99883	0.99125	17.64530
2004	8.5	0.00117	0.99883	0.99009	17.62464
2003	9.5	0.00117	0.99883	0.98893	17.60399
2002	10.5	0.00117	0.99883	0.98777	17.58338
2001	11.5	0.00117	0.99883	0.98661	17.56279
2000	12.5	0.00117	0.99883	0.98546	17.54222
1999	13.5	0.00117	0.99883	0.98431	17.52167
1998	14.5	0.00117	0.99883	0.98315	17.50115
1997	15.5	0.00117	0.99883	0.98200	17.48066
1996	16.5	0.00117	0.99883	0.98085	17.46018
1995	17.5	0.00117	0.99883	0.97970	17.43974
1994	18.5	0.00117	0.99883	0.97855	17.41931
1993	19.5	0.00117	0.99883	0.97741	17.39891
1992	20.5	0.00117	0.99883	0.97626	17.37853
1991	21.5	0.00117	0.99883	0.97512	17.35818
1990	22.5	0.00117	0.99883	0.97398	17.33785
1989	23.5	0.00117	0.99883	0.97284	17.31755
1988	24.5	0.00117	0.99883	0.97170	17.29727
1987	25.5	0.00117	0.99883	0.97056	17.27701
1986	26.5	0.00117	0.99883	0.96942	17.25678
1985	27.5	0.00117	0.99883	0.96829	17.23657
1984	28.5	0.00117	0.99883	0.96715	17.21638
1983	29.5	0.00117	0.99883	0.96602	17.19622
1982	30.5	0.00117	0.99883	0.96489	17.17608
1981	31.5	0.00117	0.99883	0.96376	17.15596
1980	32.5	0.00117	0.99883	0.96263	17.13587
1979	33.5	0.00117	0.99883	0.96150	17.11580
1978	34.5	0.00117	0.99883	0.96038	17.09576
1977	35.5	0.00117	0.99883	0.95925	17.07574
1976	36.5	0.00117	0.99883	0.95813	17.05574
1975	37.5	0.00117	0.99883	0.95701	17.03576
1974	38.5	0.00117	0.99883	0.95589	17.01581
1973	39.5	0.00117	0.99883	0.95477	16.99588
1972	40.5	0.00117	0.99883	0.95365	16.97598
1971	41.5	0.00117	0.99883	0.95253	16.95610
1970	42.5	0.00117	0.99883	0.95142	16.00468
1969	43.5	0.00117	0.99883	0.95030	15.05438
1968	44.5	0.00117	0.99883	0.94919	14.10519
1967	45.5	0.00117	0.99883	0.94808	13.15711
1966	46.5	0.00117	0.99883	0.94697	12.21014
1965	47.5	0.00117	0.99883	0.94586	11.26428
1964	48.5	0.00117	0.99883	0.94475	10.31953
1963	49.5	0.00117	0.99883	0.94365	9.37588
1962	50.5	0.00117	0.99883	0.94254	8.43334
1961	51.5	0.00117	0.99883	0.94144	7.49191
1960	52.5	0.00117	0.99883	0.94033	6.55157
1959	53.5	0.00117	0.99883	0.93923	5.61234
1958	54.5	0.00117	0.99883	0.93813	4.67421
1957	55.5	0.00117	0.99883	0.93703	3.73717
1956	56.5	0.00117	0.99883	0.93594	2.80124
1955	57.5	0.00117	0.99883	0.93484	1.86640
1954	58.5	0.00117	0.99883	0.93375	0.93265

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Burns & McDonnell SINCE 1898

Production Misc Eqpt — Account: 316

Date of Retirement (Mid Year):	2036
Interim Retirement Rate:	0.71717
Study Date, Year-End:	2012
Future Life from Study Date:	24.3
Remaining Life (F/E + .5) =	0.9

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Removal Costs	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	0	0	0	$ -	0.00000
1966	0	0	0	$ -	0.00000
1967	0	0	0	$ -	0.00000
1968	0	0	0	$ -	0.00000
1969	0	0	30	$ 30	0.00000
1970	0	0	30	$ 59	0.00000
1971	0	0	0	$ 59	0.00000
1972	0	0	0	$ 59	0.00000
1973	0	0	0	$ 59	0.00000
1974	0	0	0	$ 59	0.00000
1975	0	124	0	$ -	0.00000
1976	0	0	0	$ -	0.00000
1977	0	0	0	$ -	0.00000
1978	0	1,112	0	$ -	0.00000
1979	0	20,679	621	$ -	0.00000
1980	0	16,761	0	$ -	0.00000
1981	0	51,746	1.137	$ -	0.00000
1982	0	18,445	0	$ -	0.00000
1983	0	18.310	0	$ -	0.00000
1984	0	26,377	261	$ -	0.00000
1985	0	7,983	0	$ -	0.00000
1986	0	64,031	0	$ -	0.00000
1987	0	57,750	0	$ -	0.00000
1988	0	71,125	0	$ -	0.00000
1989	0	69,253	0	$ -	0.00000
1990	0	9,590	0	$ -	0.00000
1991	0	80.545	0	$ -	0.00000
1992	0	81,279	0	$ -	0.00000
1993	0	160.956	0	$ -	0.00000
1994	0	473,344	0	$ -	0.00000
1995	0	11,860	0	$ -	0.00000
1996	0	10,815	0	$ -	0.00000
1997	0	8,359	0	$ -	0.00000
1998	0	9.863.366	0	$ -	0.00000
1999	0	0	0	$ -	0.00000
2000	0	0	0	$ -	0.00000
2001	0	0	0	$ -	0.00000
2002	0	0	0	$ -	0.00000
2003	0	0	0	$ -	0.00000
2004	0	0	0	$ -	0.00000
2005	0	0	0	$ -	0.00000
2006	0	0	0	$ -	0.00000
2007	0	0	0	$ -	0.00000
2008	0	0	0	$ -	0.00000
2009	3,031,173	0	0	$ 3,031,173	0.00000
2010	385,851	0	0	$ 3.417.023	0.00000
2011	1,304.173	143,213	53.000	$ 4,630,983	0.03093
TOTAL	$ 4,721,197	$ 11,267,022	$ 55,078	$ 15,710,488	0.71717

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0.5	0.71717	0.28283	0.64	0.25
2011	1.5	0.71717	0.28283	0.18	0.07
2010	2.5	0.71717	0.28283	0.05	0.02
2009	3.5	0.71717	0.28283	0.01	0.01
2008	4.5	0.71717	0.28283	0	0.00
2007	5.5	0.71717	0.28283	0	0.00
2006	6.5	0.71717	0.28283	0	0.00
2005	7.5	0.71717	0.28283	0	0.00
2004	8.5	0.71717	0.28283	0	0.00
2003	9.5	0.71717	0.28283	0	0.00
2002	10.5	0.71717	0.28283	0	0.00
2001	11.5	0.71717	0.28283	0	0.00
2000	12.5	0.71717	0.28283	0	0.00
1999	13.5	0.71717	0.28283	0	0.00
1998	14.5	0.71717	0.28283	0	0.00
1997	15.5	0.71717	0.28283	0	0.00
1996	16.5	0.71717	0.28283	0	0.00
1995	17.5	0.71717	0.28283	0	0.00
1994	18.5	0.71717	0.28283	0	0.00
1993	19.5	0.71717	0.28283	0	0.00
1992	20.5	0.71717	0.28283	0	0.00
1991	21.5	0.71717	0.28283	1.95E-12	0.00
1990	22.5	0.71717	0.28283	5.51E-13	0.00
1989	23.5	0.71717	0.28283	1.56E-13	0.00
1988	24.5	0.71717	0.28283	4.40E-14	0.00
1987	25.5	0.71717	0.28283	1.25E-14	0.00
1986	26.5	0.71717	0.28283	3.52E-15	0.00
1985	27.5	0.71717	0.28283	9.97E-16	0.00
1984	28.5	0.71717	0.28283	2.82E-16	0.00
1983	29.5	0.71717	0.28283	7.97E-17	0.00
1982	30.5	0.71717	0.28283	2.25E-17	0.00
1981	31.5	0.71717	0.28283	6.38E-18	0.00
1980	32.5	0.71717	0.28283	1.80E-18	0.00
1979	33.5	0.71717	0.28283	5.10E-19	0.00
1978	34.5	0.71717	0.28283	1.44E-19	0.00
1977	35.5	0.71717	0.28283	4.08E-20	0.00
1976	36.5	0.71717	0.28283	1.15E-20	0.00
1975	37.5	0.71717	0.28283	3.26E-21	0.00
1974	38.5	0.71717	0.28283	9.23E-22	0.00
1973	39.5	0.71717	0.28283	2.61E-22	0.00
1972	40.5	0.71717	0.28283	7.39E-23	0.00
1971	41.5	0.71717	0.28283	2.09E-23	0.00
1970	42.5	0.71717	0.28283	5.91E-24	0.00
1969	43.5	0.71717	0.28283	1.67E-24	0.00
1968	44.5	0.71717	0.28283	4.73E-25	0.00
1967	45.5	0.71717	0.28283	1.34E-25	0.00
1966	46.5	0.71717	0.28283	3.78E-26	0.00
1965	47.5	0.71717	0.28283	1.07E-26	0.00
1964	48.5	0.71717	0.28283	3.02E-27	0.00
1963	49.5	0.71717	0.28283	8.55E-28	0.00
1962	50.5	0.71717	0.28283	2.42E-28	0.00
1961	51.5	0.71717	0.28283	6.84E-29	0.00
1960	52.5	0.71717	0.28283	1.94E-29	0.00
1959	53.5	0.71717	0.28283	5.47E-30	0.00
1958	54.5	0.71717	0.28283	1.55E-30	0.00
1957	55.5	0.71717	0.28283	4.38E-31	0.00
1956	56.5	0.71717	0.28283	1.24E-31	0.00
1955	57.5	0.71717	0.28283	3.50E-32	0.00
1954	58.5	0.71717	0.28283	9.91E-33	0.00

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Burns & McDonnell SINCE 1898

Production CT - Structures		Account:	341
Date of Retirement (Mid Year):			2031
Interim Retirement Rate:			0.00071
Study Date, Year-End:			2012
Future Life from Study Date:			19.3
Remaining Life (F/E + .5) =			19.4

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Removal Costs	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	0	0	0	$ -	0.00000
1966	0	0	0	$ -	0.00000
1967	0	0	0	$ -	0.00000
1968	0	0	0	$ -	0.00000
1969	0	0	0	$ -	0.00000
1970	0	0	0	$ -	0.00000
1971	0	0	0	$ -	0.00000
1972	0	0	0	$ -	0.00000
1973	0	0	0	$ -	0.00000
1974	0	0	0	$ -	0.00000
1975	0	0	0	$ -	0.00000
1976	108,617	0	0	$ 108,617	0.00000
1977	0	0	0	$ 108,617	0.00000
1978	0	0	0	$ 108,617	0.00000
1979	17,703	0	0	$ 126,320	0.00000
1980	0	0	0	$ 126,320	0.00000
1981	0	0	0	$ 126,320	0.00000
1982	0	0	0	$ 126,320	0.00000
1983	0	210	0	$ 126,110	0.00166
1984	0	0	0	$ 126,110	0.00000
1985	0	0	0	$ 126,110	0.00000
1986	0	525	0	$ 125,585	0.00418
1987	0	272	0	$ 125,313	0.00217
1988	0	0	0	$ 125,313	0.00000
1989	0	0	0	$ 125,313	0.00000
1990	0	0	0	$ 125,313	0.00000
1991	0	0	0	$ 125,313	0.00000
1992	0	0	0	$ 125,313	0.00000
1993	0	0	0	$ 125,313	0.00000
1994	0	1,080	0	$ 124,233	0.00870
1995	0	0	0	$ 124,233	0.00000
1996	0	0	0	$ 124,233	0.00000
1997	0	0	0	$ 124,233	0.00000
1998	0	0	0	$ 124,233	0.00000
1999	0	0	0	$ 124,233	0.00000
2000	0	0	0	$ 124,233	0.00000
2001	27,913	1,378	0	$ 150,768	0.00914
2002	0	0	0	$ 150,768	0.00000
2003	0	18	0	$ 150,750	0.00012
2004	0	0	0	$ 150,750	0.00000
2005	0	0	0	$ 150,750	0.00000
2006	0	0	0	$ 150,750	0.00000
2007	0	0	0	$ 150,750	0.00000
2008	0	0	0	$ 150,750	0.00000
2009	0	0	0	$ 150,750	0.00000
2010	0	0	0	$ 150,750	0.00000
2011	0	0	0	$ 150,750	0.00000
TOTAL	$ 154,233	$ 3,483	$ -	$ 4,890,907	0.00071

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1 - C)	E	F
2012	0.5	0.00071	0.99929	0.99964	18.85856
2011	1.5	0.00071	0.99929	0.99893	18.84513
2010	2.5	0.00071	0.99929	0.99822	18.83171
2009	3.5	0.00071	0.99929	0.99751	18.81830
2008	4.5	0.00071	0.99929	0.99680	18.80490
2007	5.5	0.00071	0.99929	0.99609	18.79151
2006	6.5	0.00071	0.99929	0.99538	18.77812
2005	7.5	0.00071	0.99929	0.99467	18.76475
2004	8.5	0.00071	0.99929	0.99396	18.75139
2003	9.5	0.00071	0.99929	0.99326	18.73804
2002	10.5	0.00071	0.99929	0.99255	18.72469
2001	11.5	0.00071	0.99929	0.99184	18.71136
2000	12.5	0.00071	0.99929	0.99113	18.69803
1999	13.5	0.00071	0.99929	0.99043	18.68472
1998	14.5	0.00071	0.99929	0.98972	18.67141
1997	15.5	0.00071	0.99929	0.98902	18.65812
1996	16.5	0.00071	0.99929	0.98831	18.64483
1995	17.5	0.00071	0.99929	0.98761	18.63155
1994	18.5	0.00071	0.99929	0.98691	18.61828
1993	19.5	0.00071	0.99929	0.98620	18.60503
1992	20.5	0.00071	0.99929	0.98550	18.59178
1991	21.5	0.00071	0.99929	0.98480	18.57854
1990	22.5	0.00071	0.99929	0.98410	18.56531
1989	23.5	0.00071	0.99929	0.98340	18.55209
1988	24.5	0.00071	0.99929	0.98270	18.53888
1987	25.5	0.00071	0.99929	0.98200	18.52567
1986	26.5	0.00071	0.99929	0.98130	18.51248
1985	27.5	0.00071	0.99929	0.98060	18.49930
1984	28.5	0.00071	0.99929	0.97990	18.48612
1983	29.5	0.00071	0.99929	0.97920	18.47296
1982	30.5	0.00071	0.99929	0.97851	18.45981
1981	31.5	0.00071	0.99929	0.97781	18.44666
1980	32.5	0.00071	0.99929	0.97711	18.43352
1979	33.5	0.00071	0.99929	0.97642	18.42040
1978	34.5	0.00071	0.99929	0.97572	18.40728
1977	35.5	0.00071	0.99929	0.97503	18.39417
1976	36.5	0.00071	0.99929	0.97433	18.38107
1975	37.5	0.00071	0.99929	0.97364	18.36798
1974	38.5	0.00071	0.99929	0.97295	18.35490
1973	39.5	0.00071	0.99929	0.97225	18.34183
1972	40.5	0.00071	0.99929	0.97156	18.32877
1971	41.5	0.00071	0.99929	0.97087	17.35790
1970	42.5	0.00071	0.99929	0.97018	16.38772
1969	43.5	0.00071	0.99929	0.96949	15.41824
1968	44.5	0.00071	0.99929	0.96880	14.44944
1967	45.5	0.00071	0.99929	0.96811	13.48133
1966	46.5	0.00071	0.99929	0.96742	12.51392
1965	47.5	0.00071	0.99929	0.96673	11.54719
1964	48.5	0.00071	0.99929	0.96604	10.58115
1963	49.5	0.00071	0.99929	0.96535	9.61579
1962	50.5	0.00071	0.99929	0.96466	8.65113
1961	51.5	0.00071	0.99929	0.96398	7.68715
1960	52.5	0.00071	0.99929	0.96329	6.72386
1959	53.5	0.00071	0.99929	0.96261	5.76125
1958	54.5	0.00071	0.99929	0.96192	4.79933
1957	55.5	0.00071	0.99929	0.96123	3.83810
1956	56.5	0.00071	0.99929	0.96055	2.87755
1955	57.5	0.00071	0.99929	0.95987	1.91768
1954	58.5	0.00071	0.99929	0.95916	0.95850

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Burns & McDonnell SINCE 1898

Production CT - Fuel Holders & Access Account: 342

Date of Retirement (Mid Year):	2031
Interim Retirement Rate:	0 00167
Study Date, Year-End:	2012
Future Life from Study Date:	19.3
Remaining Life (F/E + .5) =	19.2

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Removal Costs	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0 00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0 00000
1959	0	0	0	$ -	0 00000
1960	0	0	0	$ -	0 00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0 00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0 00000
1965	0	0	0	$ -	0 00000
1966	0	0	0	$ -	0 00000
1967	0	0	0	$ -	0 00000
1968	0	0	0	$ -	0 00000
1969	0	0	0	$ -	0.00000
1970	0	0	0	$ -	0.00000
1971	0	0	0	$ -	0.00000
1972	0	0	0	$ -	0.00000
1973	0	0	0	$ -	0.00000
1974	0	0	0	$ -	0 00000
1975	0	0	0	$ -	0 00000
1976	399,772	0	2.192	$ 401,963	0 00000
1977	0	0	0	$ 401,963	0 00000
1978	30.299	0	0	$ 432.262	0 00000
1979	0	0	0	$ 432.262	0.00000
1980	0	0	0	$ 432,262	0 00000
1981	0	0	0	$ 432.262	0.00000
1982	0	0	0	$ 432,262	0.00000
1983	0	0	0	$ 432,262	0.00000
1984	0	0	0	$ 432,262	0 00000
1985	0	0	0	$ 432,262	0.00000
1986	0	0	0	$ 432,262	0.00000
1987	0	0	0	$ 432,262	0 00000
1988	0	0	0	$ 432,262	0.00000
1989	0	0	0	$ 432.262	0 00000
1990	0	0	0	$ 432,262	0.00000
1991	0	0	0	$ 432,262	0 00000
1992	0	0	0	$ 432.262	0.00000
1993	8.958	1.626	0	$ 439,594	0.00370
1994	0	0	0	$ 439.594	0 00000
1995	0	0	0	$ 439.594	0 00000
1996	0	0	0	$ 439.594	0.00000
1997	0	0	0	$ 439,594	0 00000
1998	0	0	0	$ 439.594	0.00000
1999	0	0	0	$ 439,594	0 00000
2000	0	0	0	$ 439.594	0.00000
2001	19,473	0	0	$ 459,067	0.00000
2002	978,410	0	0	$ 1,437,477	0 00000
2003	0	0	0	$ 1.437,477	0.00000
2004	0	0	0	$ 1,437,477	0.00000
2005	0	0	0	$ 1,437,477	0 00000
2006	0	0	0	$ 1.437,477	0.00000
2007	0	0	0	$ 1,437,477	0.00000
2008	0	0	0	$ 1,437,477	0 00000
2009	0	0	0	$ 1,437,477	0.00000
2010	0	0	0	$ 1.437,477	0.00000
2011	49,200	43,725	20,000	$ 1.462,953	0.02989
TOTAL	$ 1,486,112	$ 45,351	$ 22,192	$ 27,126,880	0.00167

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0 5	0 00167	0.99833	0.99916	18.66990
2011	1.5	0.00167	0.99833	0 99749	18 63869
2010	2.5	0 00167	0 99833	0.99583	18 60753
2009	3.5	0 00167	0 99833	0 99416	18.57642
2008	4.5	0.00167	0.99833	0.99250	18.54537
2007	5.5	0.00167	0 99833	0 99084	18.51436
2006	6 5	0.00167	0 99833	0.98918	18.48341
2005	7.5	0.00167	0.99833	0.98753	18.45251
2004	8.5	0.00167	0.99833	0 98588	18.42166
2003	9 5	0.00167	0 99833	0.98423	18 39087
2002	10 5	0 00167	0.99833	0.98259	18.36012
2001	11.5	0.00167	0 99833	0.98094	18.32943
2000	12.5	0.00167	0 99833	0 97930	18.29878
1999	13.5	0 00167	0.99833	0.97767	18.26819
1998	14.5	0.00167	0.99833	0.97603	18.23765
1997	15.5	0.00167	0.99833	0 97440	18.20716
1996	16.5	0 00167	0.99833	0.97277	18.17672
1995	17.5	0.00167	0 99833	0.97114	18 14633
1994	18 5	0.00167	0.99833	0.96952	18 11600
1993	19.5	0.00167	0.99833	0 96790	18.08571
1992	20.5	0.00167	0.99833	0 96628	18.05548
1991	21 5	0.00167	0 99833	0.96467	18 02529
1990	22.5	0.00167	0 99833	0.96305	17.99516
1989	23.5	0.00167	0.99833	0 96144	17.96507
1988	24 5	0.00167	0.99833	0 95984	17.93504
1987	25.5	0.00167	0 99833	0.95823	17 90505
1986	26.5	0.00167	0.99833	0 95663	17.87512
1985	27.5	0 00167	0.99833	0.95503	17 84524
1984	28.5	0.00167	0.99833	0.95343	17 81540
1983	29.5	0.00167	0.99833	0.95184	17.78562
1982	30.5	0.00167	0.99833	0 95025	17.75589
1981	31.5	0 00167	0.99833	0.94866	17 72620
1980	32.5	0.00167	0.99833	0.94707	17.69657
1979	33 5	0.00167	0.99833	0 94549	17.66698
1978	34.5	0.00167	0.99833	0 94391	17.63745
1977	35.5	0.00167	0 99833	0 94233	17.60796
1976	36.5	0 00167	0 99833	0 94076	17.57852
1975	37 5	0.00167	0.99833	0.93918	17.54914
1974	38.5	0.00167	0 99833	0 93761	17.51980
1973	39.5	0 00167	0 99833	0.93605	17.49051
1972	40.5	0 00167	0.99833	0.93448	17 46127
1971	41.5	0.00167	0.99833	0 93292	16.52835
1970	42.5	0 00167	0 99833	0 93136	15 59699
1969	43.5	0 00167	0 99833	0.92980	14 66719
1968	44 5	0 00167	0.99833	0.92825	13 73894
1967	45.5	0.00167	0.99833	0 92670	12.81224
1966	46 5	0.00167	0.99833	0.92515	11 88710
1965	47.5	0.00167	0 99833	0.92360	10 96350
1964	48.5	0 00167	0 99833	0.92206	10 04144
1963	49.5	0 00167	0.99833	0.92051	9.12093
1962	50.5	0.00167	0.99833	0.91898	8 20195
1961	51.5	0.00167	0 99833	0.91744	7.28451
1960	52 5	0.00167	0.99833	0 91591	6 36861
1959	53 5	0 00167	0.99833	0 91437	5 45423
1958	54 5	0.00167	0.99833	0.91285	4.54139
1957	55.5	0.00167	0.99833	0 91132	3 63007
1956	56.5	0 00167	0 99833	0.90980	2 72027
1955	57 5	0.00167	0.99833	0.90827	1.81200
1954	58.5	0.00167	0 99833	0.90676	0.90524

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Production CT - Prime Movers Account: 343

Date of Retirement (Mid Year):	2031
Interim Retirement Rate:	0.00077
Study Date, Year-End:	2012
Future Life from Study Date:	19.3
Remaining Life (F/E + .5) =	19.4

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Removal Costs	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	0	0	0	$ -	0.00000
1966	0	0	0	$ -	0.00000
1967	0	0	0	$ -	0.00000
1968	0	0	0	$ -	0.00000
1969	0	0	0	$ -	0.00000
1970	0	0	0	$ -	0.00000
1971	0	0	0	$ -	0.00000
1972	0	0	0	$ -	0.00000
1973	0	0	0	$ -	0.00000
1974	0	0	0	$ -	0.00000
1975	0	0	0	$ -	0.00000
1976	3,778.442	0	45.438	$ 3.823,879	0.00000
1977	0	0	0	$ 3.823,879	0.00000
1978	0	0	0	$ 3,823.879	0.00000
1979	0	0	0	$ 3,823,879	0.00000
1980	0	0	0	$ 3,823,879	0.00000
1981	0	0	0	$ 3,823.879	0.00000
1982	0	0	0	$ 3,823.879	0.00000
1983	0	0	0	$ 3.823,879	0.00000
1984	0	0	0	$ 3.823,879	0.00000
1985	0	0	0	$ 3,823.879	0.00000
1986	0	0	0	$ 3,823,879	0.00000
1987	0	0	0	$ 3.823,879	0.00000
1988	0	0	0	$ 3,823,879	0.00000
1989	0	0	0	$ 3.823,879	0.00000
1990	0	0	0	$ 3.823,879	0.00000
1991	0	0	0	$ 3,823.879	0.00000
1992	0	0	0	$ 3.823,879	0.00000
1993	0	0	0	$ 3.823.879	0.00000
1994	0	0	0	$ 3,823,879	0.00000
1995	0	0	0	$ 3,823,879	0.00000
1996	287,722	118,571	0	$ 3,993,030	0.02969
1997	0	0	0	$ 3,993,030	0.00000
1998	0	0	0	$ 3.993,030	0.00000
1999	0	0	0	$ 3,993,030	0.00000
2000	0	0	0	$ 3,993,030	0.00000
2001	0	0	0	$ 3,993,030	0.00000
2002	816,466	0	0	$ 4,809,496	0.00000
2003	18.577	0	0	$ 4,828.073	0.00000
2004	0	0	0	$ 4,828.073	0.00000
2005	0	0	0	$ 4,828,073	0.00000
2006	0	0	0	$ 4,828,073	0.00000
2007	0	0	0	$ 4,828,073	0.00000
2008	14.679	0	0	$ 4,842,752	0.00000
2009	0	0	0	$ 4,842.752	0.00000
2010	0	0	0	$ 4,842,752	0.00000
2011	0	0	0	$ 4.842.752	0.00000
TOTAL	$ 4,915,886	$ 118,571	$ 45.438	$ 153,599,389	0.00077

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0.5	0.00077	0.99923	0.99961	18.84673
2011	1.5	0.00077	0.99923	0.99884	18.83218
2010	2.5	0.00077	0.99923	0.99807	18.81764
2009	3.5	0.00077	0.99923	0.99730	18.80312
2008	4.5	0.00077	0.99923	0.99653	18.78860
2007	5.5	0.00077	0.99923	0.99576	18.77410
2006	6.5	0.00077	0.99923	0.99499	18.75960
2005	7.5	0.00077	0.99923	0.99422	18.74512
2004	8.5	0.00077	0.99923	0.99346	18.73065
2003	9.5	0.00077	0.99923	0.99269	18.71619
2002	10.5	0.00077	0.99923	0.99192	18.70175
2001	11.5	0.00077	0.99923	0.99116	18.68731
2000	12.5	0.00077	0.99923	0.99039	18.67288
1999	13.5	0.00077	0.99923	0.98963	18.65847
1998	14.5	0.00077	0.99923	0.98886	18.64407
1997	15.5	0.00077	0.99923	0.98810	18.62967
1996	16.5	0.00077	0.99923	0.98734	18.61529
1995	17.5	0.00077	0.99923	0.98658	18.60092
1994	18.5	0.00077	0.99923	0.98582	18.58656
1993	19.5	0.00077	0.99923	0.98505	18.57221
1992	20.5	0.00077	0.99923	0.98429	18.55788
1991	21.5	0.00077	0.99923	0.98353	18.54355
1990	22.5	0.00077	0.99923	0.98277	18.52924
1989	23.5	0.00077	0.99923	0.98202	18.51493
1988	24.5	0.00077	0.99923	0.98126	18.50064
1987	25.5	0.00077	0.99923	0.98050	18.48636
1986	26.5	0.00077	0.99923	0.97974	18.47209
1985	27.5	0.00077	0.99923	0.97899	18.45783
1984	28.5	0.00077	0.99923	0.97823	18.44358
1983	29.5	0.00077	0.99923	0.97748	18.42934
1982	30.5	0.00077	0.99923	0.97672	18.41512
1981	31.5	0.00077	0.99923	0.97597	18.40090
1980	32.5	0.00077	0.99923	0.97521	18.38670
1979	33.5	0.00077	0.99923	0.97446	18.37250
1978	34.5	0.00077	0.99923	0.97371	18.35832
1977	35.5	0.00077	0.99923	0.97296	18.34415
1976	36.5	0.00077	0.99923	0.97221	18.32999
1975	37.5	0.00077	0.99923	0.97146	18.31584
1974	38.5	0.00077	0.99923	0.97071	18.30170
1973	39.5	0.00077	0.99923	0.96996	18.28757
1972	40.5	0.00077	0.99923	0.96921	18.27345
1971	41.5	0.00077	0.99923	0.96846	17.30499
1970	42.5	0.00077	0.99923	0.96771	16.33728
1969	43.5	0.00077	0.99923	0.96697	15.37032
1968	44.5	0.00077	0.99923	0.96622	14.40410
1967	45.5	0.00077	0.99923	0.96547	13.43862
1966	46.5	0.00077	0.99923	0.96473	12.47390
1965	47.5	0.00077	0.99923	0.96398	11.50991
1964	48.5	0.00077	0.99923	0.96324	10.54668
1963	49.5	0.00077	0.99923	0.96250	9.58418
1962	50.5	0.00077	0.99923	0.96175	8.62243
1961	51.5	0.00077	0.99923	0.96101	7.66142
1960	52.5	0.00077	0.99923	0.96027	6.70115
1959	53.5	0.00077	0.99923	0.95953	5.74162
1958	54.5	0.00077	0.99923	0.95879	4.78284
1957	55.5	0.00077	0.99923	0.95805	3.82479
1956	56.5	0.00077	0.99923	0.95731	2.86749
1955	57.5	0.00077	0.99923	0.95657	1.91092
1954	58.5	0.00077	0.99923	0.95583	0.95509

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Burns & McDonnell SINCE 1898

Production CT - Generators Account: 344

Date of Retirement (Mid Year):	2031
Interim Retirement Rate:	0.00000
Study Date, Year-End:	2012
Future Life from Study Date:	19.3
Remaining Life (F/E + .5) =	19.5

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Adjustments and Transfers	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	0	0	0	$ -	0.00000
1966	0	0	0	$ -	0.00000
1967	0	0	0	$ -	0.00000
1968	0	0	0	$ -	0.00000
1969	0	0	0	$ -	0.00000
1970	0	0	0	$ -	0.00000
1971	0	0	0	$ -	0.00000
1972	0	0	0	$ -	0.00000
1973	0	0	0	$ -	0.00000
1974	0	0	0	$ -	0.00000
1975	0	0	0	$ -	0.00000
1976	1,102,964	0	0	$ 1,102,964	0.00000
1977	0	0	0	$ 1,102,964	0.00000
1978	0	0	0	$ 1,102,964	0.00000
1979	0	0	0	$ 1,102,964	0.00000
1980	0	0	0	$ 1,102,964	0.00000
1981	0	0	0	$ 1,102,964	0.00000
1982	0	0	0	$ 1,102,964	0.00000
1983	0	0	0	$ 1,102,964	0.00000
1984	0	0	0	$ 1,102,964	0.00000
1985	0	0	0	$ 1,102,964	0.00000
1986	0	0	0	$ 1,102,964	0.00000
1987	0	0	0	$ 1,102,964	0.00000
1988	0	0	0	$ 1,102,964	0.00000
1989	0	0	0	$ 1,102,964	0.00000
1990	0	0	0	$ 1,102,964	0.00000
1991	0	0	0	$ 1,102,964	0.00000
1992	0	0	0	$ 1,102,964	0.00000
1993	0	0	0	$ 1,102,964	0.00000
1994	0	0	0	$ 1,102,964	0.00000
1995	0	0	0	$ 1,102,964	0.00000
1996	0	0	0	$ 1,102,964	0.00000
1997	0	0	0	$ 1,102,964	0.00000
1998	0	0	0	$ 1,102,964	0.00000
1999	0	0	0	$ 1,102,964	0.00000
2000	0	0	0	$ 1,102,964	0.00000
2001	0	0	0	$ 1,102,964	0.00000
2002	0	0	0	$ 1,102,964	0.00000
2003	0	0	0	$ 1,102,964	0.00000
2004	0	0	0	$ 1,102,964	0.00000
2005	0	0	0	$ 1,102,964	0.00000
2006	0	0	0	$ 1,102,964	0.00000
2007	0	0	0	$ 1,102,964	0.00000
2008	0	0	0	$ 1,102,964	0.00000
2009	0	0	0	$ 1,102,964	0.00000
2010	0	0	0	$ 1,102,964	0.00000
2011	0	0	0	$ 1,102,964	0.00000
TOTAL	$ 1,102,964	$ -	$ -	$ 40,809,656	0.00000

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1 - C)	E	F
2012	0.5	-	1.00000	1.00000	19.00000
2011	1.5	-	1.00000	1.00000	19.00000
2010	2.5	-	1.00000	1.00000	19.00000
2009	3.5	-	1.00000	1.00000	19.00000
2008	4.5	-	1.00000	1.00000	19.00000
2007	5.5	-	1.00000	1.00000	19.00000
2006	6.5	-	1.00000	1.00000	19.00000
2005	7.5	-	1.00000	1.00000	19.00000
2004	8.5	-	1.00000	1.00000	19.00000
2003	9.5	-	1.00000	1.00000	19.00000
2002	10.5	-	1.00000	1.00000	19.00000
2001	11.5	-	1.00000	1.00000	19.00000
2000	12.5	-	1.00000	1.00000	19.00000
1999	13.5	-	1.00000	1.00000	19.00000
1998	14.5	-	1.00000	1.00000	19.00000
1997	15.5	-	1.00000	1.00000	19.00000
1996	16.5	-	1.00000	1.00000	19.00000
1995	17.5	-	1.00000	1.00000	19.00000
1994	18.5	-	1.00000	1.00000	19.00000
1993	19.5	-	1.00000	1.00000	19.00000
1992	20.5	-	1.00000	1.00000	19.00000
1991	21.5	-	1.00000	1.00000	19.00000
1990	22.5	-	1.00000	1.00000	19.00000
1989	23.5	-	1.00000	1.00000	19.00000
1988	24.5	-	1.00000	1.00000	19.00000
1987	25.5	-	1.00000	1.00000	19.00000
1986	26.5	-	1.00000	1.00000	19.00000
1985	27.5	-	1.00000	1.00000	19.00000
1984	28.5	-	1.00000	1.00000	19.00000
1983	29.5	-	1.00000	1.00000	19.00000
1982	30.5	-	1.00000	1.00000	19.00000
1981	31.5	-	1.00000	1.00000	19.00000
1980	32.5	-	1.00000	1.00000	19.00000
1979	33.5	-	1.00000	1.00000	19.00000
1978	34.5	-	1.00000	1.00000	19.00000
1977	35.5	-	1.00000	1.00000	19.00000
1976	36.5	-	1.00000	1.00000	19.00000
1975	37.5	-	1.00000	1.00000	19.00000
1974	38.5	-	1.00000	1.00000	19.00000
1973	39.5	-	1.00000	1.00000	19.00000
1972	40.5	-	1.00000	1.00000	19.00000
1971	41.5	-	1.00000	1.00000	18.00000
1970	42.5	-	1.00000	1.00000	17.00000
1969	43.5	-	1.00000	1.00000	16.00000
1968	44.5	-	1.00000	1.00000	15.00000
1967	45.5	-	1.00000	1.00000	14.00000
1966	46.5	-	1.00000	1.00000	13.00000
1965	47.5	-	1.00000	1.00000	12.00000
1964	48.5	-	1.00000	1.00000	11.00000
1963	49.5	-	1.00000	1.00000	10.00000
1962	50.5	-	1.00000	1.00000	9.00000
1961	51.5	-	1.00000	1.00000	8.00000
1960	52.5	-	1.00000	1.00000	7.00000
1959	53.5	-	1.00000	1.00000	6.00000
1958	54.5	-	1.00000	1.00000	5.00000
1957	55.5	-	1.00000	1.00000	4.00000
1956	56.5	-	1.00000	1.00000	3.00000
1955	57.5	-	1.00000	1.00000	2.00000
1954	58.5	-	1.00000	1.00000	1.00000

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Burns & McDonnell SINCE 1898

Production CT - Access Elec. Eqpt. Account: 345

Date of Retirement (Mid Year):	2031
Interim Retirement Rate:	0.00318
Study Date, Year-End:	2012
Future Life from Study Date:	19.3
Remaining Life (F/E + 5) =	18.9

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Removal Costs	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	0	0	0	$ -	0.00000
1966	0	0	0	$ -	0.00000
1967	0	0	0	$ -	0.00000
1968	0	0	0	$ -	0.00000
1969	0	0	0	$ -	0.00000
1970	0	0	0	$ -	0.00000
1971	0	0	0	$ -	0.00000
1972	0	0	0	$ -	0.00000
1973	0	0	0	$ -	0.00000
1974	0	0	0	$ -	0.00000
1975	0	0	0	$ -	0.00000
1976	190,437	0	0	$ 190,437	0.00000
1977	0	0	0	$ 190,437	0.00000
1978	0	0	0	$ 190,437	0.00000
1979	0	0	0	$ 190,437	0.00000
1980	0	0	0	$ 190,437	0.00000
1981	0	0	0	$ 190,437	0.00000
1982	0	0	0	$ 190,437	0.00000
1983	0	0	0	$ 190,437	0.00000
1984	0	0	0	$ 190,437	0.00000
1985	0	0	0	$ 190,437	0.00000
1986	0	0	0	$ 190,437	0.00000
1987	0	0	0	$ 190,437	0.00000
1988	0	0	0	$ 190,437	0.00000
1989	0	0	0	$ 190,437	0.00000
1990	0	0	0	$ 190,437	0.00000
1991	0	0	0	$ 190,437	0.00000
1992	0	0	0	$ 190,437	0.00000
1993	0	0	0	$ 190,437	0.00000
1994	0	542	0	$ 189,894	0.00286
1995	0	0	0	$ 189,894	0.00000
1996	0	0	0	$ 189,894	0.00000
1997	0	0	0	$ 189,894	0.00000
1998	0	0	0	$ 189,894	0.00000
1999	0	0	0	$ 189,894	0.00000
2000	0	0	0	$ 189,894	0.00000
2001	0	1,274	0	$ 188,621	0.00675
2002	0	0	0	$ 188,621	0.00000
2003	16,445	0	0	$ 205,066	0.00000
2004	0	0	0	$ 205,066	0.00000
2005	58,789	6,020	0	$ 257,835	0.02335
2006	0	0	0	$ 257,835	0.00000
2007	52,055	0	0	$ 309,890	0.00000
2008	0	0	0	$ 309,890	0.00000
2009	0	0	0	$ 309,890	0.00000
2010	82,632	16,838	4,700	$ 380,383	0.04427
2011	15,754	0	0	$ 396,138	0.00000
TOTAL	$ 416,112	$ 24,675	$ 4,700	$ 7,766,354	0.00318

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1 - C)	E	F
2012	0.5	0.00318	0.99682	0.99841	18.37646
2011	1.5	0.00318	0.99682	0.99524	18.32007
2010	2.5	0.00318	0.99682	0.99208	18.26187
2009	3.5	0.00318	0.99682	0.98893	18.20385
2008	4.5	0.00318	0.99682	0.98578	18.14601
2007	5.5	0.00318	0.99682	0.98265	18.08836
2006	6.5	0.00318	0.99682	0.97953	18.03089
2005	7.5	0.00318	0.99682	0.97642	17.97360
2004	8.5	0.00318	0.99682	0.97332	17.91650
2003	9.5	0.00318	0.99682	0.97022	17.85958
2002	10.5	0.00318	0.99682	0.96714	17.80284
2001	11.5	0.00318	0.99682	0.96407	17.74627
2000	12.5	0.00318	0.99682	0.96100	17.68989
1999	13.5	0.00318	0.99682	0.95795	17.63369
1998	14.5	0.00318	0.99682	0.95491	17.57766
1997	15.5	0.00318	0.99682	0.95187	17.52182
1996	16.5	0.00318	0.99682	0.94885	17.46615
1995	17.5	0.00318	0.99682	0.94584	17.41066
1994	18.5	0.00318	0.99682	0.94283	17.35534
1993	19.5	0.00318	0.99682	0.93983	17.30020
1992	20.5	0.00318	0.99682	0.93685	17.24524
1991	21.5	0.00318	0.99682	0.93387	17.19045
1990	22.5	0.00318	0.99682	0.93091	17.13583
1989	23.5	0.00318	0.99682	0.92795	17.08139
1988	24.5	0.00318	0.99682	0.92500	17.02712
1987	25.5	0.00318	0.99682	0.92206	16.97302
1986	26.5	0.00318	0.99682	0.91913	16.91910
1985	27.5	0.00318	0.99682	0.91621	16.86534
1984	28.5	0.00318	0.99682	0.91330	16.81176
1983	29.5	0.00318	0.99682	0.91040	16.75835
1982	30.5	0.00318	0.99682	0.90751	16.70511
1981	31.5	0.00318	0.99682	0.90462	16.65203
1980	32.5	0.00318	0.99682	0.90175	16.59913
1979	33.5	0.00318	0.99682	0.89888	16.54639
1978	34.5	0.00318	0.99682	0.89603	16.49382
1977	35.5	0.00318	0.99682	0.89318	16.44142
1976	36.5	0.00318	0.99682	0.89034	16.38918
1975	37.5	0.00318	0.99682	0.88751	16.33711
1974	38.5	0.00318	0.99682	0.88470	16.28521
1973	39.5	0.00318	0.99682	0.88188	16.23347
1972	40.5	0.00318	0.99682	0.87908	16.18189
1971	41.5	0.00318	0.99682	0.87629	15.30560
1970	42.5	0.00318	0.99682	0.87351	14.43210
1969	43.5	0.00318	0.99682	0.87073	13.56136
1968	44.5	0.00318	0.99682	0.86796	12.69340
1967	45.5	0.00318	0.99682	0.86521	11.82819
1966	46.5	0.00318	0.99682	0.86246	10.96574
1965	47.5	0.00318	0.99682	0.85972	10.10602
1964	48.5	0.00318	0.99682	0.85699	9.24903
1963	49.5	0.00318	0.99682	0.85426	8.39477
1962	50.5	0.00318	0.99682	0.85155	7.54322
1961	51.5	0.00318	0.99682	0.84884	6.69438
1960	52.5	0.00318	0.99682	0.84615	5.84823
1959	53.5	0.00318	0.99682	0.84346	5.00477
1958	54.5	0.00318	0.99682	0.84078	4.16399
1957	55.5	0.00318	0.99682	0.83811	3.32589
1956	56.5	0.00318	0.99682	0.83544	2.49044
1955	57.5	0.00318	0.99682	0.83279	1.65765
1954	58.5	0.00318	0.99682	0.83014	0.82751

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Burns & McDonnell SINCE 1898

Transmission Structures	Account:	352
Date of Retirement (Mid Year):		2036
Interim Retirement Rate:		0.00088
Study Date, Year-End:		2012
Future Life from Study Date:		23.8
Remaining Life (F/E + 5) =		23.3

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Removal Costs	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	20,160	0	27	$ 20.187	0.00000
1966	40.763	0	27	$ 60,977	0.00000
1967	0	0	121	$ 61,098	0.00000
1968	43,613	0	16	$ 104,727	0.00000
1969	259,615	0	1.139	$ 365,482	0.00000
1970	58,666	0	0	$ 424,148	0.00000
1971	4,943	651	63	$ 428,502	0.00152
1972	14,525	0	0	$ 443,028	0.00000
1973	.610	294	1,194	$ 444,537	0.00066
1974	5,647	3,692	111	$ 446,602	0.00827
1975	235,954	1,395	934	$ 682,094	0.00205
1976	18.559	491	105	$ 700,268	0.00070
1977	209	667	33	$ 699,843	0.00095
1978	102.849	329	0	$ 802,362	0.00041
1979	405.482	1,485	0	$ 1,206.360	0.00123
1980	599,906	443	1	$ 1.805,824	0.00025
1981	79,726	870	83	$ 1,884,762	0.00046
1982	438,495	0	156	$ 2.323.413	0.00000
1983	18,555	462	0	$ 2,341,507	0.00020
1984	978.796	35.682	0	$ 3,284.620	0.01086
1985	222,378	0	0	$ 3,506,998	0.00000
1986	2,256,609	0	0	$ 5,763.608	0.00000
1987	0	1,876	0	$ 5,761,732	0.00033
1988	3,577	468	0	$ 5,764,841	0.00008
1989	787	746	0	$ 5,764,882	0.00013
1990	16,452	37.975	0	$ 5.743,360	0.00661
1991	605	0	0	$ 5,743.965	0.00000
1992	35,886	6.671	0	$ 5,773,179	0.00116
1993	2,244	3,465	0	$ 5,771,958	0.00060
1994	75.274	987	0	$ 5.846,246	0.00017
1995	0	14,474	0	$ 5,831,771	0.00248
1996	0	4,625	0	$ 5,827.146	0.00079
1997	77.151	0	0	$ 5,904.298	0.00000
1998	36,801	10,364	0	$ 5,930,734	0.00175
1999	671	5,379	0	$ 5,926,026	0.00091
2000	0	107	0	$ 5,925,920	0.00002
2001	8,031	10.118	0	$ 5,923,832	0.00171
2002	97.730	0	0	$ 6,021,562	0.00000
2003	49,786	6,545	0	$ 6,064,803	0.00108
2004	9,861	0	0	$ 6.074,664	0.00000
2005	0	0	0	$ 6,074,664	0.00000
2006	273,626	1,834	0	$ 6,346,456	0.00029
2007	0	0	0	$ 6,346,456	0.00000
2008	225,774	0	0	$ 6,572,231	0.00000
2009	5.029	1.432	0	$ 6,575,828	0.00022
2010	323.951	4.372	679	$ 6,896.086	0.00063
2011	12.489	0	0	$ 6,908,576	0.00000
TOTAL	$ 7,061,787	$ 157.899	$ 4,686	$ 179.122,164	0.00088

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	*Unrealized Life* of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0.5	0.00088	0.99912	0.99956	22.74824
2011	1.5	0.00088	0.99912	0.99868	22.72818
2010	2.5	0.00088	0.99912	0.99780	22.70815
2009	3.5	0.00088	0.99912	0.99692	22.68813
2008	4.5	0.00088	0.99912	0.99604	22.66813
2007	5.5	0.00088	0.99912	0.99516	22.64815
2006	6.5	0.00088	0.99912	0.99428	22.62818
2005	7.5	0.00088	0.99912	0.99341	22.60824
2004	8.5	0.00088	0.99912	0.99253	22.58831
2003	9.5	0.00088	0.99912	0.99166	22.56839
2002	10.5	0.00088	0.99912	0.99078	22.54850
2001	11.5	0.00088	0.99912	0.98991	22.52862
2000	12.5	0.00088	0.99912	0.98904	22.50876
1999	13.5	0.00088	0.99912	0.98816	22.48892
1998	14.5	0.00088	0.99912	0.98729	22.46910
1997	15.5	0.00088	0.99912	0.98642	22.44929
1996	16.5	0.00088	0.99912	0.98555	22.42950
1995	17.5	0.00088	0.99912	0.98469	22.40973
1994	18.5	0.00088	0.99912	0.98382	22.38997
1993	19.5	0.00088	0.99912	0.98295	22.37024
1992	20.5	0.00088	0.99912	0.98208	22.35052
1991	21.5	0.00088	0.99912	0.98122	22.33081
1990	22.5	0.00088	0.99912	0.98035	22.31113
1989	23.5	0.00088	0.99912	0.97949	22.29146
1988	24.5	0.00088	0.99912	0.97863	22.27181
1987	25.5	0.00088	0.99912	0.97776	22.25218
1986	26.5	0.00088	0.99912	0.97690	22.23256
1985	27.5	0.00088	0.99912	0.97604	22.21296
1984	28.5	0.00088	0.99912	0.97518	22.19338
1983	29.5	0.00088	0.99912	0.97432	22.17382
1982	30.5	0.00088	0.99912	0.97346	22.15427
1981	31.5	0.00088	0.99912	0.97260	22.13474
1980	32.5	0.00088	0.99912	0.97174	22.11523
1979	33.5	0.00088	0.99912	0.97089	22.09574
1978	34.5	0.00088	0.99912	0.97003	22.07626
1977	35.5	0.00088	0.99912	0.96918	22.05680
1976	36.5	0.00088	0.99912	0.96832	22.03735
1975	37.5	0.00088	0.99912	0.96747	21.06989
1974	38.5	0.00088	0.99912	0.96662	20.10327
1973	39.5	0.00088	0.99912	0.96576	19.13750
1972	40.5	0.00088	0.99912	0.96491	18.17259
1971	41.5	0.00088	0.99912	0.96406	17.20853
1970	42.5	0.00088	0.99912	0.96321	16.24532
1969	43.5	0.00088	0.99912	0.96236	15.28295
1968	44.5	0.00088	0.99912	0.96152	14.32144
1967	45.5	0.00088	0.99912	0.96067	13.36077
1966	46.5	0.00088	0.99912	0.95982	12.40095
1965	47.5	0.00088	0.99912	0.95897	11.44197
1964	48.5	0.00088	0.99912	0.95813	10.48384
1963	49.5	0.00088	0.99912	0.95728	9.52656
1962	50.5	0.00088	0.99912	0.95644	8.57012
1961	51.5	0.00088	0.99912	0.95560	7.61452
1960	52.5	0.00088	0.99912	0.95476	6.65976
1959	53.5	0.00088	0.99912	0.95391	5.70585
1958	54.5	0.00088	0.99912	0.95307	4.75278
1957	55.5	0.00088	0.99912	0.95223	3.80054
1956	56.5	0.00088	0.99912	0.95139	2.84915
1955	57.5	0.00088	0.99912	0.95055	1.89860
1954	58.5	0.00088	0.99912	0.94972	0.94888

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Burns & McDonnell SINCE 1898

Transmission Station Eqpt — Account: 353

Date of Retirement (Mid Year):	2036
Interim Retirement Rate:	0.00692
Study Date. Year-End:	2012
Future Life from Study Date:	23.8
Remaining Life (F/E + .5) =	23.4

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Removal Costs	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	152	$ 152	0.00000
1956	0	0	105	$ 256	0.00000
1957	0	0	0	$ 256	0.00000
1958	0	0	122	$ 379	0.00000
1959	0	0	422	$ 800	0.00000
1960	0	0	0	$ 800	0.00000
1961	0	0	161	$ 961	0.00000
1962	0	0	234	$ 1,195	0.00000
1963	0	0	0	$ 1,195	0.00000
1964	0	0	0	$ 1,195	0.00000
1965	419,714	5,035	4,825	$ 420,699	0.01197
1966	1,221,762	0	1,641	$ 1,644,102	0.00000
1967	1,474	0	5,421	$ 1,650,997	0.00000
1968	945,361	0	7,024	$ 2,603,381	0.00000
1969	3,144,331	3,574	21,755	$ 5,765,893	0.00062
1970	934,369	1,556	4,020	$ 6,702,726	0.00023
1971	376,657	4,337	2,938	$ 7,077,984	0.00061
1972	271,870	6,243	1,011	$ 7,344,622	0.00085
1973	1,593,104	251,447	5,865	$ 8,692,144	0.02893
1974	199,178	24,004	1,244	$ 8,868,562	0.00271
1975	1,954,922	72,258	10,640	$ 10,761,865	0.00671
1976	666,720	13,284	610	$ 11,415,911	0.00116
1977	1,840,851	3,445	2,715	$ 13,256,032	0.00026
1978	2,073,381	9,421	1,194	$ 15,321,186	0.00061
1979	3,301,427	70,870	1,430	$ 18,553,174	0.00382
1980	984,231	23,149	1,678	$ 19,515,933	0.00119
1981	2,755,462	63,090	3,278	$ 22,211,583	0.00284
1982	3,757,786	328,828	1,369	$ 25,641,911	0.01282
1983	940,709	8,084	11,828	$ 26,586,364	0.00030
1984	9,650,017	780,185	4,514	$ 35,460,710	0.02200
1985	1,709,016	19,519	4,901	$ 37,155,108	0.00053
1986	42,240,181	253,465	6,594	$ 79,148,418	0.00320
1987	1,070,692	24,687	1,306	$ 80,195,728	0.00031
1988	160,672	41,780	252	$ 80,314,871	0.00052
1989	393,258	34,043	1,544	$ 80,675,631	0.00042
1990	2,389,256	410,741	1,820	$ 82,655,965	0.00497
1991	49,569	37,817	285	$ 82,668,002	0.00046
1992	732,313	129,609	655	$ 83,271,361	0.00156
1993	1,239,184	1,259,780	867	$ 83,251,632	0.01513
1994	881,759	239,686	80	$ 83,893,784	0.00286
1995	74,232	242,935	393	$ 83,725,474	0.00290
1996	508,704	34,148	1,456	$ 84,201,486	0.00041
1997	1,085,676	19,620	551	$ 85,268,093	0.00023
1998	123,115	182,053	839	$ 85,209,993	0.00214
1999	3,199,950	192,792	670	$ 88,217,822	0.00219
2000	2,487,663	339,531	58	$ 90,366,011	0.00376
2001	975,817	461,633	436	$ 90,880,630	0.00508
2002	1,028,798	124,490	84	$ 91,785,023	0.00136
2003	1,481,578	269,518	0	$ 92,997,083	0.00290
2004	2,792,932	7,785,162	19	$ 88,004,672	0.08846
2005	232,344	65,400	3	$ 88,171,820	0.00074
2006	5,571,841	1,165,164	275	$ 92,578,772	0.01259
2007	245,661	2,399,085	0	$ 90,425,347	0.02653
2008	7,444,270	43,008	0	$ 97,826,610	0.00044
2009	120,432	2,438	0	$ 97,944,604	0.00002
2010	14,350,069	310,037	26,368	$ 112,013,004	0.00277
2011	1,075,366	192,774	490	$ 112,896,086	0.00171
TOTAL	$ 130,697,671	$ 17,949,725	$ 148,140	$ 2,595,246,192	0.00692

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0.5	0.00692	0.99308	0.99654	22.79265
2011	1.5	0.00692	0.99308	0.98965	22.63501
2010	2.5	0.00692	0.99308	0.98280	22.47846
2009	3.5	0.00692	0.99308	0.97601	22.32299
2008	4.5	0.00692	0.99308	0.96926	22.16860
2007	5.5	0.00692	0.99308	0.96255	22.01527
2006	6.5	0.00692	0.99308	0.95590	21.86300
2005	7.5	0.00692	0.99308	0.94928	21.71179
2004	8.5	0.00692	0.99308	0.94272	21.56162
2003	9.5	0.00692	0.99308	0.93620	21.41249
2002	10.5	0.00692	0.99308	0.92972	21.26440
2001	11.5	0.00692	0.99308	0.92329	21.11732
2000	12.5	0.00692	0.99308	0.91691	20.97127
1999	13.5	0.00692	0.99308	0.91057	20.82622
1998	14.5	0.00692	0.99308	0.90427	20.68218
1997	15.5	0.00692	0.99308	0.89801	20.53914
1996	16.5	0.00692	0.99308	0.89180	20.39708
1995	17.5	0.00692	0.99308	0.88563	20.25600
1994	18.5	0.00692	0.99308	0.87951	20.11591
1993	19.5	0.00692	0.99308	0.87343	19.97678
1992	20.5	0.00692	0.99308	0.86738	19.83861
1991	21.5	0.00692	0.99308	0.86139	19.70140
1990	22.5	0.00692	0.99308	0.85543	19.56514
1989	23.5	0.00692	0.99308	0.84951	19.42982
1988	24.5	0.00692	0.99308	0.84364	19.29543
1987	25.5	0.00692	0.99308	0.83780	19.16198
1986	26.5	0.00692	0.99308	0.83201	19.02945
1985	27.5	0.00692	0.99308	0.82625	18.89783
1984	28.5	0.00692	0.99308	0.82054	18.76713
1983	29.5	0.00692	0.99308	0.81486	18.63732
1982	30.5	0.00692	0.99308	0.80923	18.50842
1981	31.5	0.00692	0.99308	0.80363	18.38041
1980	32.5	0.00692	0.99308	0.79807	18.25328
1979	33.5	0.00692	0.99308	0.79255	18.12704
1978	34.5	0.00692	0.99308	0.78707	18.00166
1977	35.5	0.00692	0.99308	0.78163	17.22004
1976	36.5	0.00692	0.99308	0.77622	16.44382
1975	37.5	0.00692	0.99308	0.77085	15.67297
1974	38.5	0.00692	0.99308	0.76552	14.90745
1973	39.5	0.00692	0.99308	0.76023	14.14722
1972	40.5	0.00692	0.99308	0.75497	13.39225
1971	41.5	0.00692	0.99308	0.74975	12.64251
1970	42.5	0.00692	0.99308	0.74456	11.89795
1969	43.5	0.00692	0.99308	0.73941	11.15854
1968	44.5	0.00692	0.99308	0.73430	10.42424
1967	45.5	0.00692	0.99308	0.72922	9.69502
1966	46.5	0.00692	0.99308	0.72417	8.97085
1965	47.5	0.00692	0.99308	0.71917	8.25168
1964	48.5	0.00692	0.99308	0.71419	7.53749
1963	49.5	0.00692	0.99308	0.70925	6.82824
1962	50.5	0.00692	0.99308	0.70435	6.12389
1961	51.5	0.00692	0.99308	0.69947	5.42442
1960	52.5	0.00692	0.99308	0.69464	4.72978
1959	53.5	0.00692	0.99308	0.68983	4.03995
1958	54.5	0.00692	0.99308	0.68506	3.35489
1957	55.5	0.00692	0.99308	0.68032	2.67456
1956	56.5	0.00692	0.99308	0.67562	1.99895
1955	57.5	0.00692	0.99308	0.67095	1.32800
1954	58.5	0.00692	0.99308	0.66630	0.66170

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Burns & McDonnell SINCE 1898

Transmission Towers *Account:* 354

Date of Retirement (Mid Year):	2041
Interim Retirement Rate:	0.00002
Study Date, Year-End:	2012
Future Life from Study Date:	28.8
Remaining Life (F/E + .5) =	28.5

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Removal Costs	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	0	0	0	$ -	0.00000
1966	0	0	0	$ -	0.00000
1967	309,097	0	0	$ 309,097	0.00000
1968	139,879	0	0	$ 448,976	0.00000
1969	157,055	0	0	$ 606,032	0.00000
1970	0	0	0	$ 606,032	0.00000
1971	0	0	0	$ 606,032	0.00000
1972	0	0	0	$ 606,032	0.00000
1973	0	0	0	$ 606,032	0.00000
1974	0	0	0	$ 606,032	0.00000
1975	0	0	0	$ 606,032	0.00000
1976	380,892	0	0	$ 986,924	0.00000
1977	4,019	0	145	$ 991,089	0.00000
1978	3,721	0	0	$ 994,809	0.00000
1979	78,240	0	0	$ 1,073,049	0.00000
1980	80,487	0	0	$ 1,153,536	0.00000
1981	4,893	0	0	$ 1,158,429	0.00000
1982	88,103	0	0	$ 1,246,532	0.00000
1983	14,694	0	0	$ 1,261,226	0.00000
1984	460,143	0	0	$ 1,721,370	0.00000
1985	0	0	0	$ 1,721,370	0.00000
1986	5,595,769	0	0	$ 7,317,138	0.00000
1987	0	0	0	$ 7,317,138	0.00000
1988	0	0	0	$ 7,317,138	0.00000
1989	0	0	0	$ 7,317,138	0.00000
1990	10,759	0	0	$ 7,327,897	0.00000
1991	0	3,667	0	$ 7,324,231	0.00050
1992	0	0	0	$ 7,324,231	0.00000
1993	0	0	0	$ 7,324,231	0.00000
1994	0	0	0	$ 7,324,231	0.00000
1995	0	0	0	$ 7,324,231	0.00000
1996	0	0	0	$ 7,324,231	0.00000
1997	0	0	0	$ 7,324,231	0.00000
1998	0	0	0	$ 7,324,231	0.00000
1999	0	0	0	$ 7,324,231	0.00000
2000	0	0	0	$ 7,324,231	0.00000
2001	0	445	0	$ 7,323,786	0.00006
2002	0	0	0	$ 7,323,786	0.00000
2003	6,688	0	0	$ 7,330,474	0.00000
2004	0	0	0	$ 7,330,474	0.00000
2005	0	0	0	$ 7,330,474	0.00000
2006	0	0	0	$ 7,330,474	0.00000
2007	0	0	0	$ 7,330,474	0.00000
2008	1,259,104	0	0	$ 8,589,578	0.00000
2009	0	0	0	$ 8,589,578	0.00000
2010	1,259,104	0	0	$ 9,848,682	0.00000
2011	42,360	0	0	$ 9,891,042	0.00000
TOTAL	$ 9,895,009	$ 4,112	$ 145	$ 215,366,205	0.00002

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0.5	0.00002	0.99998	0.99999	27.99198
2011	1.5	0.00002	0.99998	0.99997	27.99145
2010	2.5	0.00002	0.99998	0.99995	27.99091
2009	3.5	0.00002	0.99998	0.99993	27.99038
2008	4.5	0.00002	0.99998	0.99991	27.98985
2007	5.5	0.00002	0.99998	0.99989	27.98931
2006	6.5	0.00002	0.99998	0.99988	27.98878
2005	7.5	0.00002	0.99998	0.99986	27.98824
2004	8.5	0.00002	0.99998	0.99984	27.98771
2003	9.5	0.00002	0.99998	0.99982	27.98717
2002	10.5	0.00002	0.99998	0.99980	27.98664
2001	11.5	0.00002	0.99998	0.99978	27.98610
2000	12.5	0.00002	0.99998	0.99976	27.98557
1999	13.5	0.00002	0.99998	0.99974	27.98504
1998	14.5	0.00002	0.99998	0.99972	27.98450
1997	15.5	0.00002	0.99998	0.99970	27.98397
1996	16.5	0.00002	0.99998	0.99969	27.98343
1995	17.5	0.00002	0.99998	0.99967	27.98290
1994	18.5	0.00002	0.99998	0.99965	27.98236
1993	19.5	0.00002	0.99998	0.99963	27.98183
1992	20.5	0.00002	0.99998	0.99961	27.98130
1991	21.5	0.00002	0.99998	0.99959	27.98076
1990	22.5	0.00002	0.99998	0.99957	27.98023
1989	23.5	0.00002	0.99998	0.99955	27.97969
1988	24.5	0.00002	0.99998	0.99953	27.97916
1987	25.5	0.00002	0.99998	0.99951	27.97863
1986	26.5	0.00002	0.99998	0.99949	27.97809
1985	27.5	0.00002	0.99998	0.99948	27.97756
1984	28.5	0.00002	0.99998	0.99946	27.97702
1983	29.5	0.00002	0.99998	0.99944	27.97649
1982	30.5	0.00002	0.99998	0.99942	27.97595
1981	31.5	0.00002	0.99998	0.99940	27.97542
1980	32.5	0.00002	0.99998	0.99938	26.97604
1979	33.5	0.00002	0.99998	0.99936	25.97668
1978	34.5	0.00002	0.99998	0.99934	24.97734
1977	35.5	0.00002	0.99998	0.99932	23.97802
1976	36.5	0.00002	0.99998	0.99930	22.97871
1975	37.5	0.00002	0.99998	0.99928	21.97943
1974	38.5	0.00002	0.99998	0.99927	20.98016
1973	39.5	0.00002	0.99998	0.99925	19.98092
1972	40.5	0.00002	0.99998	0.99923	18.98169
1971	41.5	0.00002	0.99998	0.99921	17.98248
1970	42.5	0.00002	0.99998	0.99919	16.98329
1969	43.5	0.00002	0.99998	0.99917	15.98412
1968	44.5	0.00002	0.99998	0.99915	14.98497
1967	45.5	0.00002	0.99998	0.99913	13.98584
1966	46.5	0.00002	0.99998	0.99911	12.98673
1965	47.5	0.00002	0.99998	0.99909	11.98763
1964	48.5	0.00002	0.99998	0.99907	10.98856
1963	49.5	0.00002	0.99998	0.99906	9.98950
1962	50.5	0.00002	0.99998	0.99904	8.99047
1961	51.5	0.00002	0.99998	0.99902	7.99145
1960	52.5	0.00002	0.99998	0.99900	6.99245
1959	53.5	0.00002	0.99998	0.99898	5.99347
1958	54.5	0.00002	0.99998	0.99896	4.99451
1957	55.5	0.00002	0.99998	0.99894	3.99557
1956	56.5	0.00002	0.99998	0.99892	2.99665
1955	57.5	0.00002	0.99998	0.99890	1.99775
1954	58.5	0.00002	0.99998	0.99888	0.99886

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Burns & McDonnell SINCE 1898

Transmission	Poles	Account:	355

Date of Retirement (Mid Year):	2033
Interim Retirement Rate:	0.00000
Study Date, Year-End:	2012
Future Life from Study Date:	20.8
Remaining Life (F/E + .5) =	20.5

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Adjustments and Transfers	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	0	0	0	$ -	0.00000
1966	0	0	0	$ -	0.00000
1967	57,283	0	0	$ 57,283	0.00000
1968	0	0	0	$ 57,283	0.00000
1969	24,190	0	0	$ 81,473	0.00000
1970	0	0	0	$ 81,473	0.00000
1971	0	0	0	$ 81,473	0.00000
1972	0	0	0	$ 81,473	0.00000
1973	0	0	0	$ 81,473	0.00000
1974	0	0	0	$ 81,473	0.00000
1975	0	0	0	$ 81,473	0.00000
1976	152,841	0	0	$ 234,314	0.00000
1977	0	0	0	$ 234,314	0.00000
1978	0	0	0	$ 234,314	0.00000
1979	0	0	0	$ 234,314	0.00000
1980	0	0	0	$ 234,314	0.00000
1981	0	0	0	$ 234,314	0.00000
1982	0	0	0	$ 234,314	0.00000
1983	0	0	0	$ 234,314	0.00000
1984	0	0	0	$ 234,314	0.00000
1985	0	0	0	$ 234,314	0.00000
1986	0	0	0	$ 234,314	0.00000
1987	0	0	0	$ 234,314	0.00000
1988	0	0	0	$ 234,314	0.00000
1989	0	0	0	$ 234,314	0.00000
1990	0	0	0	$ 234,314	0.00000
1991	0	0	0	$ 234,314	0.00000
1992	0	0	0	$ 234,314	0.00000
1993	0	0	0	$ 234,314	0.00000
1994	0	0	0	$ 234,314	0.00000
1995	0	0	0	$ 234,314	0.00000
1996	0	0	0	$ 234,314	0.00000
1997	0	0	0	$ 234,314	0.00000
1998	0	0	0	$ 234,314	0.00000
1999	0	0	0	$ 234,314	0.00000
2000	0	0	0	$ 234,314	0.00000
2001	0	0	0	$ 234,314	0.00000
2002	0	0	0	$ 234,314	0.00000
2003	0	0	0	$ 234,314	0.00000
2004	0	0	0	$ 234,314	0.00000
2005	0	0	0	$ 234,314	0.00000
2006	0	0	0	$ 234,314	0.00000
2007	0	0	0	$ 234,314	0.00000
2008	0	0	0	$ 234,314	0.00000
2009	0	0	0	$ 234,314	0.00000
2010	0	0	0	$ 234,314	0.00000
2011	0	0	0	$ 234,314	0.00000
TOTAL	$ 234,314	$ -	$ -	$ 9,354,502	0.00000

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1 - C)	E	F
2012	0.5	-	1.00000	1.00000	20.00000
2011	1.5	-	1.00000	1.00000	20.00000
2010	2.5	-	1.00000	1.00000	20.00000
2009	3.5	-	1.00000	1.00000	20.00000
2008	4.5	-	1.00000	1.00000	20.00000
2007	5.5	-	1.00000	1.00000	20.00000
2006	6.5	-	1.00000	1.00000	20.00000
2005	7.5	-	1.00000	1.00000	20.00000
2004	8.5	-	1.00000	1.00000	20.00000
2003	9.5	-	1.00000	1.00000	20.00000
2002	10.5	-	1.00000	1.00000	20.00000
2001	11.5	-	1.00000	1.00000	20.00000
2000	12.5	-	1.00000	1.00000	20.00000
1999	13.5	-	1.00000	1.00000	20.00000
1998	14.5	-	1.00000	1.00000	20.00000
1997	15.5	-	1.00000	1.00000	20.00000
1996	16.5	-	1.00000	1.00000	20.00000
1995	17.5	-	1.00000	1.00000	20.00000
1994	18.5	-	1.00000	1.00000	20.00000
1993	19.5	-	1.00000	1.00000	20.00000
1992	20.5	-	1.00000	1.00000	20.00000
1991	21.5	-	1.00000	1.00000	20.00000
1990	22.5	-	1.00000	1.00000	20.00000
1989	23.5	-	1.00000	1.00000	20.00000
1988	24.5	-	1.00000	1.00000	20.00000
1987	25.5	-	1.00000	1.00000	20.00000
1986	26.5	-	1.00000	1.00000	20.00000
1985	27.5	-	1.00000	1.00000	20.00000
1984	28.5	-	1.00000	1.00000	20.00000
1983	29.5	-	1.00000	1.00000	20.00000
1982	30.5	-	1.00000	1.00000	20.00000
1981	31.5	-	1.00000	1.00000	20.00000
1980	32.5	-	1.00000	1.00000	20.00000
1979	33.5	-	1.00000	1.00000	20.00000
1978	34.5	-	1.00000	1.00000	20.00000
1977	35.5	-	1.00000	1.00000	20.00000
1976	36.5	-	1.00000	1.00000	20.00000
1975	37.5	-	1.00000	1.00000	20.00000
1974	38.5	-	1.00000	1.00000	20.00000
1973	39.5	-	1.00000	1.00000	20.00000
1972	40.5	-	1.00000	1.00000	19.00000
1971	41.5	-	1.00000	1.00000	18.00000
1970	42.5	-	1.00000	1.00000	17.00000
1969	43.5	-	1.00000	1.00000	16.00000
1968	44.5	-	1.00000	1.00000	15.00000
1967	45.5	-	1.00000	1.00000	14.00000
1966	46.5	-	1.00000	1.00000	13.00000
1965	47.5	-	1.00000	1.00000	12.00000
1964	48.5	-	1.00000	1.00000	11.00000
1963	49.5	-	1.00000	1.00000	10.00000
1962	50.5	-	1.00000	1.00000	9.00000
1961	51.5	-	1.00000	1.00000	8.00000
1960	52.5	-	1.00000	1.00000	7.00000
1959	53.5	-	1.00000	1.00000	6.00000
1958	54.5	-	1.00000	1.00000	5.00000
1957	55.5	-	1.00000	1.00000	4.00000
1956	56.5	-	1.00000	1.00000	3.00000
1955	57.5	-	1.00000	1.00000	2.00000
1954	58.5	-	1.00000	1.00000	1.00000

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Burns & McDonnell SINCE 1898

Transmission Lines | Account: 356

Date of Retirement (Mid Year):	2036
Interim Retirement Rate:	0.00000
Study Date. Year-End:	2012
Future Life from Study Date:	23.8
Remaining Life (E/E + .5) =	23.5

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Adjustments and Transfers	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	0	0	0	$ -	0.00000
1966	0	0	0	$ -	0.00000
1967	39,131	0	0	$ 39,131	0.00000
1968	0	0	0	$ 39,131	0.00000
1969	23,026	0	0	$ 62,157	0.00000
1970	0	0	0	$ 62,157	0.00000
1971	0	0	0	$ 62,157	0.00000
1972	0	0	0	$ 62,157	0.00000
1973	0	0	0	$ 62,157	0.00000
1974	0	0	0	$ 62,157	0.00000
1975	0	0	0	$ 62,157	0.00000
1976	24,744	0	0	$ 86,901	0.00000
1977	0	0	0	$ 86,901	0.00000
1978	0	0	0	$ 86,901	0.00000
1979	0	0	0	$ 86,901	0.00000
1980	0	0	0	$ 86,901	0.00000
1981	5,676,547	0	0	$ 5,763,448	0.00000
1982	937,496	0	0	$ 6,700,944	0.00000
1983	210,765	0	0	$ 6,911,708	0.00000
1984	2,812,421	0	0	$ 9,724,129	0.00000
1985	45,223	0	0	$ 9,769,352	0.00000
1986	19,197,453	0	0	$ 28,966,805	0.00000
1987	180,019	0	0	$ 29,146,824	0.00000
1988	431,211	0	0	$ 29,578,035	0.00000
1989	255,513	0	0	$ 29,833,548	0.00000
1990	396,302	0	0	$ 30,229,849	0.00000
1991	68,804	0	0	$ 30,298,653	0.00000
1992	20,895	0	0	$ 30,319,549	0.00000
1993	77,924	0	0	$ 30,397,473	0.00000
1994	817,484	0	0	$ 31,214,957	0.00000
1995	74,339	0	0	$ 31,289,296	0.00000
1996	89,079	0	0	$ 31,378,375	0.00000
1997	1,179,392	0	0	$ 32,557,768	0.00000
1998	111,806	0	0	$ 32,669,574	0.00000
1999	672,219	0	0	$ 33,341,792	0.00000
2000	184,561	0	0	$ 33,526,354	0.00000
2001	699,346	0	0	$ 34,225,700	0.00000
2002	816,626	0	0	$ 35,042,326	0.00000
2003	432,410	0	0	$ 35,474,735	0.00000
2004	602,337	0	0	$ 36,077,073	0.00000
2005	242,723	0	0	$ 36,319,795	0.00000
2006	684,660	0	0	$ 37,004,455	0.00000
2007	137,405	0	0	$ 37,141,860	0.00000
2008	2,892,857	0	0	$ 40,034,717	0.00000
2009	0	0	0	$ 40,034,717	0.00000
2010	0	0	0	$ 40,034,717	0.00000
2011	0	0	0	$ 40,034,717	0.00000
TOTAL	$ 40,034,717	$ -	$ -	$ 915,991,114	0.00000

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0.5	-	1.00000	1.00000	23.00000
2011	1.5	-	1.00000	1.00000	23.00000
2010	2.5	-	1.00000	1.00000	23.00000
2009	3.5	-	1.00000	1.00000	23.00000
2008	4.5	-	1.00000	1.00000	23.00000
2007	5.5	-	1.00000	1.00000	23.00000
2006	6.5	-	1.00000	1.00000	23.00000
2005	7.5	-	1.00000	1.00000	23.00000
2004	8.5	-	1.00000	1.00000	23.00000
2003	9.5	-	1.00000	1.00000	23.00000
2002	10.5	-	1.00000	1.00000	23.00000
2001	11.5	-	1.00000	1.00000	23.00000
2000	12.5	-	1.00000	1.00000	23.00000
1999	13.5	-	1.00000	1.00000	23.00000
1998	14.5	-	1.00000	1.00000	23.00000
1997	15.5	-	1.00000	1.00000	23.00000
1996	16.5	-	1.00000	1.00000	23.00000
1995	17.5	-	1.00000	1.00000	23.00000
1994	18.5	-	1.00000	1.00000	23.00000
1993	19.5	-	1.00000	1.00000	23.00000
1992	20.5	-	1.00000	1.00000	23.00000
1991	21.5	-	1.00000	1.00000	23.00000
1990	22.5	-	1.00000	1.00000	23.00000
1989	23.5	-	1.00000	1.00000	23.00000
1988	24.5	-	1.00000	1.00000	23.00000
1987	25.5	-	1.00000	1.00000	23.00000
1986	26.5	-	1.00000	1.00000	23.00000
1985	27.5	-	1.00000	1.00000	23.00000
1984	28.5	-	1.00000	1.00000	23.00000
1983	29.5	-	1.00000	1.00000	23.00000
1982	30.5	-	1.00000	1.00000	23.00000
1981	31.5	-	1.00000	1.00000	23.00000
1980	32.5	-	1.00000	1.00000	23.00000
1979	33.5	-	1.00000	1.00000	23.00000
1978	34.5	-	1.00000	1.00000	23.00000
1977	35.5	-	1.00000	1.00000	23.00000
1976	36.5	-	1.00000	1.00000	23.00000
1975	37.5	-	1.00000	1.00000	22.00000
1974	38.5	-	1.00000	1.00000	21.00000
1973	39.5	-	1.00000	1.00000	20.00000
1972	40.5	-	1.00000	1.00000	19.00000
1971	41.5	-	1.00000	1.00000	18.00000
1970	42.5	-	1.00000	1.00000	17.00000
1969	43.5	-	1.00000	1.00000	16.00000
1968	44.5	-	1.00000	1.00000	15.00000
1967	45.5	-	1.00000	1.00000	14.00000
1966	46.5	-	1.00000	1.00000	13.00000
1965	47.5	-	1.00000	1.00000	12.00000
1964	48.5	-	1.00000	1.00000	11.00000
1963	49.5	-	1.00000	1.00000	10.00000
1962	50.5	-	1.00000	1.00000	9.00000
1961	51.5	-	1.00000	1.00000	8.00000
1960	52.5	-	1.00000	1.00000	7.00000
1959	53.5	-	1.00000	1.00000	6.00000
1958	54.5	-	1.00000	1.00000	5.00000
1957	55.5	-	1.00000	1.00000	4.00000
1956	56.5	-	1.00000	1.00000	3.00000
1955	57.5	-	1.00000	1.00000	2.00000
1954	58.5	-	1.00000	1.00000	1.00000

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Burns & McDonnell SINCE 1898

General Plant Structures | Account: 390

Date of Retirement (Mid Year): 2024
Interim Retirement Rate: 0.01388
Study Date, Year-End: 2012
Future Life from Study Date: 11.5
Remaining Life (F/E + .5) = 11.5

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Removal Costs	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	0	0	0	$ -	0.00000
1966	213,961	0	0	$ 213,961	0.00000
1967	0	0	0	$ 213,961	0.00000
1968	2,483	0	0	$ 216,444	0.00000
1969	0	0	0	$ 216,444	0.00000
1970	267,258	0	0	$ 483,702	0.00000
1971	43,988	0	269	$ 527,959	0.00000
1972	0	4,598	0	$ 523,362	0.00878
1973	21,835	0	0	$ 545,197	0.00000
1974	37,731	2,500	0	$ 580,428	0.00431
1975	592	0	0	$ 581,020	0.00000
1976	1,704	0	208	$ 582,932	0.00000
1977	3,783	0	0	$ 586,715	0.00000
1978	4,808	0	0	$ 591,523	0.00000
1979	29,345	3,716	0	$ 617,153	0.00602
1980	1,269	0	0	$ 618,422	0.00000
1981	2,270,658	0	15,658	$ 2,904,737	0.00000
1982	190,816	0	0	$ 3,095,553	0.00000
1983	0	61,332	0	$ 3,034,221	0.02021
1984	0	0	0	$ 3,034,221	0.00000
1985	148,462	0	0	$ 3,182,684	0.00000
1986	0	0	0	$ 3,182,684	0.00000
1987	0	0	0	$ 3,182,684	0.00000
1988	24,337	0	0	$ 3,207,020	0.00000
1989	0	0	0	$ 3,207,020	0.00000
1990	1,995	0	0	$ 3,209,015	0.00000
1991	10,168	0	0	$ 3,219,183	0.00000
1992	0	0	0	$ 3,219,183	0.00000
1993	0	0	0	$ 3,219,183	0.00000
1994	126,550	5,086	0	$ 3,340,646	0.00152
1995	0	0	0	$ 3,340,646	0.00000
1996	0	0	0	$ 3,340,646	0.00000
1997	0	0	0	$ 3,340,646	0.00000
1998	10,867	18,258	0	$ 3,333,255	0.00548
1999	4,389	0	0	$ 3,337,644	0.00000
2000	0	984,851	0	$ 2,352,793	0.41859
2001	3,972	1,737	0	$ 2,355,027	0.00074
2002	31,276	1,099	0	$ 2,385,204	0.00046
2003	0	0	0	$ 2,385,204	0.00000
2004	3,785	3,761	0	$ 2,385,228	0.00158
2005	199,739	36,488	0	$ 2,548,479	0.01432
2006	10,205	2,514	0	$ 2,556,170	0.00098
2007	10,972	2,873	0	$ 2,564,269	0.00112
2008	4,742	-120	0	$ 2,569,131	-0.00005
2009	263,205	0	0	$ 2,832,336	0.00000
2010	4,039	0	0	$ 2,836,375	0.00000
2011	1,560,508	258,221	0	$ 4,138,662	0.06239
TOTAL	$ 5,509,442	$ 1,386,914	$ 16,134	$ 99,938,974	0.01388

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0.5	0.01388	0.98612	0.99306	10.89464
2011	1.5	0.01388	0.98612	0.97928	10.74345
2010	2.5	0.01388	0.98612	0.96569	10.59435
2009	3.5	0.01388	0.98612	0.95229	10.44733
2008	4.5	0.01388	0.98612	0.93907	10.30235
2007	5.5	0.01388	0.98612	0.92604	10.15937
2006	6.5	0.01388	0.98612	0.91319	10.01839
2005	7.5	0.01388	0.98612	0.90052	9.87935
2004	8.5	0.01388	0.98612	0.88802	9.74225
2003	9.5	0.01388	0.98612	0.87570	9.60705
2002	10.5	0.01388	0.98612	0.86354	9.47373
2001	11.5	0.01388	0.98612	0.85156	9.34226
2000	12.5	0.01388	0.98612	0.83974	9.21261
1999	13.5	0.01388	0.98612	0.82809	9.08476
1998	14.5	0.01388	0.98612	0.81660	8.95869
1997	15.5	0.01388	0.98612	0.80526	8.83436
1996	16.5	0.01388	0.98612	0.79409	8.71176
1995	17.5	0.01388	0.98612	0.78307	8.59086
1994	18.5	0.01388	0.98612	0.77220	8.47164
1993	19.5	0.01388	0.98612	0.76149	8.35408
1992	20.5	0.01388	0.98612	0.75092	8.23814
1991	21.5	0.01388	0.98612	0.74050	8.12382
1990	22.5	0.01388	0.98612	0.73022	8.01108
1989	23.5	0.01388	0.98612	0.72009	7.89990
1988	24.5	0.01388	0.98612	0.71009	7.79027
1987	25.5	0.01388	0.98612	0.70024	7.68216
1986	26.5	0.01388	0.98612	0.69052	7.57555
1985	27.5	0.01388	0.98612	0.68094	7.47042
1984	28.5	0.01388	0.98612	0.67149	7.36675
1983	29.5	0.01388	0.98612	0.66217	7.26452
1982	30.5	0.01388	0.98612	0.65298	7.16370
1981	31.5	0.01388	0.98612	0.64392	7.06429
1980	32.5	0.01388	0.98612	0.63498	6.96625
1979	33.5	0.01388	0.98612	0.62617	6.86958
1978	34.5	0.01388	0.98612	0.61748	6.77424
1977	35.5	0.01388	0.98612	0.60891	6.68023
1976	36.5	0.01388	0.98612	0.60046	6.58753
1975	37.5	0.01388	0.98612	0.59213	6.49611
1974	38.5	0.01388	0.98612	0.58391	6.40596
1973	39.5	0.01388	0.98612	0.57581	6.31706
1972	40.5	0.01388	0.98612	0.56782	6.22939
1971	41.5	0.01388	0.98612	0.55994	6.14294
1970	42.5	0.01388	0.98612	0.55217	6.05769
1969	43.5	0.01388	0.98612	0.54450	5.97363
1968	44.5	0.01388	0.98612	0.53695	5.89073
1967	45.5	0.01388	0.98612	0.52950	5.80898
1966	46.5	0.01388	0.98612	0.52215	5.72836
1965	47.5	0.01388	0.98612	0.51490	5.64887
1964	48.5	0.01388	0.98612	0.50776	5.14111
1963	49.5	0.01388	0.98612	0.50071	4.64040
1962	50.5	0.01388	0.98612	0.49376	4.14664
1961	51.5	0.01388	0.98612	0.48691	3.65973
1960	52.5	0.01388	0.98612	0.48015	3.17958
1959	53.5	0.01388	0.98612	0.47349	2.70609
1958	54.5	0.01388	0.98612	0.46692	2.23917
1957	55.5	0.01388	0.98612	0.46044	1.77873
1956	56.5	0.01388	0.98612	0.45405	1.32469
1955	57.5	0.01388	0.98612	0.44775	0.87694
1954	58.5	0.01388	0.98612	0.44153	0.43541

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Burns & McDonnell SINCE 1898

General Plant   Office Furniture & Equipment   Account: 391.0, 391.6, 391.7

Date of Retirement (Mid Year):	2018
Interim Retirement Rate:	2.43677
Study Date, Year-End:	2012
Future Life from Study Date:	6.0
Remaining Life (F/E + .5) =	2.42

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Removal Costs	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	0	0	0	$ -	0.00000
1966	0	0	0	$ -	0.00000
1967	0	0	0	$ -	0.00000
1968	0	0	0	$ -	0.00000
1969	0	0	0	$ -	0.00000
1970	0	0	0	$ -	0.00000
1971	1,873	0	0	$ 1,873	0.00000
1972	0	0	0	$ 1,873	0.00000
1973	0	0	0	$ 1,873	0.00000
1974	3,825	0	0	$ 5,699	0.00000
1975	0	0	0	$ 5,699	0.00000
1976	0	0	0	$ 5,699	0.00000
1977	502	0	80	$ 6,281	0.00000
1978	10,533	1,444	664	$ 16,034	0.09004
1979	3,276	6,879	0	$ 12,431	0.55343
1980	4,635	3,291	0	$ 13,775	0.23892
1981	18,913	2,175	0	$ 30,512	0.07128
1982	32,904	11,112	0	$ 52,305	0.21244
1983	14,814	12,216	0	$ 54,902	0.22251
1984	52,080	12,836	63	$ 94,208	0.13626
1985	617	9,631	0	$ 85,193	0.11305
1986	5,651	38,293	0	$ 52,551	0.72868
1987	44,954	18,352	0	$ 79,153	0.23186
1988	15,044	58,299	0	$ 35,898	1.62403
1989	7,003	48,703	0	$ -	0.00000
1990	41,091	74,156	0	$ -	0.00000
1991	43,689	86,235	0	$ -	0.00000
1992	18,617	79,202	0	$ -	0.00000
1993	23,789	9,177	0	$ 14,612	0.62804
1994	1,685	84,556	0	$ -	0.00000
1995	15,609	7,290	0	$ 8,318	0.87639
1996	1,380	32,731	0	$ -	0.00000
1997	5,099	5,122	0	$ -	0.00000
1998	5,434	823,912	0	$ -	0.00000
1999	1,662	610,952	0	$ -	0.00000
2000	5,735	253,451	0	$ -	0.00000
2001	970	164,948	0	$ -	0.00000
2002	7,514	98,450	0	$ -	0.00000
2003	5,377	22,360	0	$ -	0.00000
2004	38,804	59,698	0	$ -	0.00000
2005	5,183	60,703	0	$ -	0.00000
2006	9,433	5,129	0	$ 4,304	1.19158
2007	36,882	22,689	0	$ 18,498	1.22657
2008	35,410	25,457	0	$ 28,450	0.89482
2009	96,149	4,748	0	$ 119,851	0.03961
2010	57,224	47,688	0	$ 129,387	0.36857
2011	173,132	22,733	0	$ 279,786	0.08125
TOTAL	$ 846,491	$ 2,824,621	$ 806	$ 1,159,165	2.43677

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0.5	2.43677	(1.43677)	(0)	(0)
2011	1.5	2.43677	(1.43677)	0	1
2010	2.5	2.43677	(1.43677)	(0)	(1)
2009	3.5	2.43677	(1.43677)	1	1
2008	4.5	2.43677	(1.43677)	(1)	(2)
2007	5.5	2.43677	(1.43677)	1	3
2006	6.5	2.43677	(1.43677)	(2)	(4)
2005	7.5	2.43677	(1.43677)	3	5
2004	8.5	2.43677	(1.43677)	(4)	(8)
2003	9.5	2.43677	(1.43677)	6	11
2002	10.5	2.43677	(1.43677)	(8)	(16)
2001	11.5	2.43677	(1.43677)	12	23
2000	12.5	2.43677	(1.43677)	(17)	(32)
1999	13.5	2.43677	(1.43677)	24	47
1998	14.5	2.43677	(1.43677)	(35)	(67)
1997	15.5	2.43677	(1.43677)	50	96
1996	16.5	2.43677	(1.43677)	(72)	(138)
1995	17.5	2.43677	(1.43677)	103	199
1994	18.5	2.43677	(1.43677)	(149)	(286)
1993	19.5	2.43677	(1.43677)	214	411
1992	20.5	2.43677	(1.43677)	(307)	(590)
1991	21.5	2.43677	(1.43677)	441	848
1990	22.5	2.43677	(1.43677)	(634)	(1,218)
1989	23.5	2.43677	(1.43677)	9.10E+02	1,750
1988	24.5	2.43677	(1.43677)	-1.31E+03	(2,515)
1987	25.5	2.43677	(1.43677)	1.88E+03	3,613
1986	26.5	2.43677	(1.43677)	-2.70E+03	(5,191)
1985	27.5	2.43677	(1.43677)	3.88E+03	7,459
1984	28.5	2.43677	(1.43677)	-5.57E+03	(10,717)
1983	29.5	2.43677	(1.43677)	8.01E+03	15,398
1982	30.5	2.43677	(1.43677)	-1.15E+04	(22,123)
1981	31.5	2.43677	(1.43677)	1.65E+04	31,786
1980	32.5	2.43677	(1.43677)	-2.37E+04	(45,669)
1979	33.5	2.43677	(1.43677)	3.41E+04	65,616
1978	34.5	2.43677	(1.43677)	-4.90E+04	(94,275)
1977	35.5	2.43677	(1.43677)	7.04E+04	135,452
1976	36.5	2.43677	(1.43677)	-1.01E+05	(194,614)
1975	37.5	2.43677	(1.43677)	1.45E+05	279,616
1974	38.5	2.43677	(1.43677)	-2.09E+05	(401,744)
1973	39.5	2.43677	(1.43677)	3.00E+05	577,215
1972	40.5	2.43677	(1.43677)	-4.31E+05	(829,327)
1971	41.5	2.43677	(1.43677)	6.20E+05	1,191,554
1970	42.5	2.43677	(1.43677)	-8.90E+05	(1,711,993)
1969	43.5	2.43677	(1.43677)	1.28E+06	2,459,744
1968	44.5	2.43677	(1.43677)	-1.84E+06	(3,534,093)
1967	45.5	2.43677	(1.43677)	2.64E+06	5,077,689
1966	46.5	2.43677	(1.43677)	-3.79E+06	(7,295,485)
1965	47.5	2.43677	(1.43677)	5.45E+06	10,481,954
1964	48.5	2.43677	(1.43677)	-7.83E+06	(15,060,186)
1963	49.5	2.43677	(1.43677)	1.13E+07	21,638,065
1962	50.5	2.43677	(1.43677)	-1.62E+07	(31,088,982)
1961	51.5	2.43677	(1.43677)	2.32E+07	44,667,801
1960	52.5	2.43677	(1.43677)	-3.34E+07	(64,177,478)
1959	53.5	2.43677	(1.43677)	4.80E+07	92,208,451
1958	54.5	2.43677	(1.43677)	-6.89E+07	(132,482,588)
1957	55.5	2.43677	(1.43677)	9.90E+07	190,347,370
1956	56.5	2.43677	(1.43677)	-1.42E+08	332,566,439
1955	57.5	2.43677	(1.43677)	2.04E+08	128,229,959
1954	58.5	2.43677	(1.43677)	-2.94E+08	421,815,041

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Burns & McDonnell SINCE 1898

General Plant Computer System 34 Account: 391.2

Date of Retirement (Mid Year):	2019
Interim Retirement Rate:	0.15077
Study Date, Year-End:	2012
Future Life from Study Date:	7.0
Remaining Life (F/E + 5) =	4.8

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Removal Costs	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	0	0	0	$ -	0.00000
1966	0	0	0	$ -	0.00000
1967	0	0	0	$ -	0.00000
1968	0	0	0	$ -	0.00000
1969	0	0	0	$ -	0.00000
1970	0	0	0	$ -	0.00000
1971	0	0	0	$ -	0.00000
1972	0	0	0	$ -	0.00000
1973	0	0	0	$ -	0.00000
1974	0	0	0	$ -	0.00000
1975	0	0	0	$ -	0.00000
1976	0	0	0	$ -	0.00000
1977	0	0	0	$ -	0.00000
1978	0	0	0	$ -	0.00000
1979	0	0	0	$ -	0.00000
1980	0	0	0	$ -	0.00000
1981	0	0	0	$ -	0.00000
1982	0	0	0	$ -	0.00000
1983	20,178	0	0	$ 20,178	0.00000
1984	11,301	0	0	$ 31,478	0.00000
1985	566	0	0	$ 32,045	0.00000
1986	10,031	6,339	0	$ 35,736	0.17740
1987	10,070	102,442	0	$ -	0.00000
1988	2,044	348,449	0	$ -	0.00000
1989	68,513	96,391	0	$ -	0.00000
1990	10,095	584,760	0	$ -	0.00000
1991	152,299	26,119	0	$ 126,180	0.20700
1992	29,619	185,213	0	$ -	0.00000
1993	35,184	192,662	0	$ -	0.00000
1994	38,603	124,760	0	$ -	0.00000
1995	12,868	36,495	0	$ -	0.00000
1996	24,760	50,601	0	$ -	0.00000
1997	69,444	0	0	$ 69,444	0.00000
1998	104,612	826,943	0	$ -	0.00000
1999	6,579	921,279	0	$ -	0.00000
2000	161,462	239,043	0	$ -	0.00000
2001	171,377	632,084	0	$ -	0.00000
2002	280,680	35,782	0	$ 244,899	0.14611
2003	195,951	17,817	0	$ 423,032	0.04212
2004	1,866,261	503,286	0	$ 1,786,007	0.28179
2005	1,235,236	542,314	0	$ 2,478,929	0.21877
2006	709,512	80,829	0	$ 3,107,613	0.02601
2007	417,952	333,455	0	$ 3,192,110	0.10446
2008	943,959	205,735	0	$ 3,930,334	0.05235
2009	371,495	125,711	0	$ 4,176,118	0.03010
2010	452,166	88,697	0	$ 4,539,587	0.01954
2011	13,099,021	0	0	$ 17,638,608	0.00000
TOTAL	$ 20,511,837	$ 6,307,204	$ -	$ 41,832,299	0.15077

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0.5	0.15077	0.84923	0.92461	4.01147
2011	1.5	0.15077	0.84923	0.78521	3.40664
2010	2.5	0.15077	0.84923	0.66682	2.89301
2009	3.5	0.15077	0.84923	0.56628	2.45682
2008	4.5	0.15077	0.84923	0.48090	2.08640
2007	5.5	0.15077	0.84923	0.40839	1.77183
2006	6.5	0.15077	0.84923	0.34682	1.50468
2005	7.5	0.15077	0.84923	0.29453	1.27781
2004	8.5	0.15077	0.84923	0.25012	1.08515
2003	9.5	0.15077	0.84923	0.21241	0.92154
2002	10.5	0.15077	0.84923	0.18038	0.78260
2001	11.5	0.15077	0.84923	0.15319	0.66460
2000	12.5	0.15077	0.84923	0.13009	0.56440
1999	13.5	0.15077	0.84923	0.11048	0.47930
1998	14.5	0.15077	0.84923	0.09382	0.40704
1997	15.5	0.15077	0.84923	0.07967	0.34567
1996	16.5	0.15077	0.84923	0.06766	0.29355
1995	17.5	0.15077	0.84923	0.05746	0.24929
1994	18.5	0.15077	0.84923	0.04880	0.21170
1993	19.5	0.15077	0.84923	0.04144	0.17978
1992	20.5	0.15077	0.84923	0.03519	0.15268
1991	21.5	0.15077	0.84923	0.02989	0.12966
1990	22.5	0.15077	0.84923	0.02538	0.11011
1989	23.5	0.15077	0.84923	0.02155	0.09351
1988	24.5	0.15077	0.84923	0.01830	0.07941
1987	25.5	0.15077	0.84923	0.01554	0.06744
1986	26.5	0.15077	0.84923	0.01320	0.05727
1985	27.5	0.15077	0.84923	0.01121	0.04863
1984	28.5	0.15077	0.84923	0.00952	0.04130
1983	29.5	0.15077	0.84923	0.00808	0.03507
1982	30.5	0.15077	0.84923	0.00687	0.02979
1981	31.5	0.15077	0.84923	0.00583	0.02529
1980	32.5	0.15077	0.84923	0.00495	0.02148
1979	33.5	0.15077	0.84923	0.00420	0.01824
1978	34.5	0.15077	0.84923	0.00357	0.01549
1977	35.5	0.15077	0.84923	0.00303	0.01316
1976	36.5	0.15077	0.84923	0.00258	0.01117
1975	37.5	0.15077	0.84923	0.00219	0.00949
1974	38.5	0.15077	0.84923	0.00186	0.00806
1973	39.5	0.15077	0.84923	0.00158	0.00684
1972	40.5	0.15077	0.84923	0.00134	0.00581
1971	41.5	0.15077	0.84923	0.00114	0.00493
1970	42.5	0.15077	0.84923	0.00097	0.00419
1969	43.5	0.15077	0.84923	0.00082	0.00356
1968	44.5	0.15077	0.84923	0.00070	0.00302
1967	45.5	0.15077	0.84923	0.00059	0.00257
1966	46.5	0.15077	0.84923	0.00050	0.00218
1965	47.5	0.15077	0.84923	0.00043	0.00185
1964	48.5	0.15077	0.84923	0.00036	0.00157
1963	49.5	0.15077	0.84923	0.00031	0.00133
1962	50.5	0.15077	0.84923	0.00026	0.00113
1961	51.5	0.15077	0.84923	0.00022	0.00091
1960	52.5	0.15077	0.84923	0.00019	0.00072
1959	53.5	0.15077	0.84923	0.00016	0.00056
1958	54.5	0.15077	0.84923	0.00014	0.00043
1957	55.5	0.15077	0.84923	0.00012	0.00031
1956	56.5	0.15077	0.84923	0.00010	0.00021
1955	57.5	0.15077	0.84923	0.00008	0.00013
1954	58.5	0.15077	0.84923	0.00007	0.00006

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Burns & McDonnell SINCE 1898

General Plant Vehicles General	Account:	392.2
Date of Retirement (Mid Year):		2015
Interim Retirement Rate:		1 13891
Study Date, Year-End:		2012
Future Life from Study Date:		3 0
Remaining Life (F/E + 5) =		0 4

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Adjustments and Transfers	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0 00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0 00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0 00000
1959	0	0	0	$ -	0 00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0 00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0 00000
1965	0	0	0	$ -	0.00000
1966	0	0	0	$ -	0 00000
1967	0	0	0	$ -	0.00000
1968	0	0	0	$ -	0 00000
1969	0	0	0	$ -	0.00000
1970	0	0	0	$ -	0.00000
1971	0	0	0	$ -	0 00000
1972	0	0	0	$ -	0.00000
1973	5.547	0	0	$ 5.547	0.00000
1974	0	0	0	$ 5.547	0 00000
1975	0	0	0	$ 5,547	0.00000
1976	0	3,816	0	$ 1.731	2.20427
1977	0	20.858	0	$ -	0 00000
1978	5.200	25,542	0	$ -	0.00000
1979	4.459	50,625	0	$ -	0 00000
1980	0	67.299	0	$ -	0.00000
1981	6,870	29,321	0	$ -	0 00000
1982	3.075	50,194	0	$ -	0.00000
1983	3.716	67,323	0	$ -	0 00000
1984	0	69,038	0	$ -	0.00000
1985	0	156,989	0	$ -	0.00000
1986	0	166,898	0	$ -	0.00000
1987	1.727	31,901	0	$ -	0.00000
1988	0	103,137	0	$ -	0.00000
1989	0	107,488	0	$ -	0 00000
1990	0	197,186	0	$ -	0 00000
1991	11.036	265,309	0	$ -	0 00000
1992	0	204,469	0	$ -	0 00000
1993	6,201	59,955	0	$ -	0.00000
1994	2.953	130.235	0	$ -	0 00000
1995	0	85,465	0	$ -	0 00000
1996	32,532	50.415	0	$ -	0 00000
1997	0	77.751	0	$ -	0.00000
1998	148,830	1,361,164	0	$ -	0 00000
1999	3,065	32,959	0	$ -	0 00000
2000	83,659	66.492	0	$ 17.167	3.87322
2001	92,501	66,715	0	$ 42.953	1.55321
2002	174.304	196,182	0	$ 21,076	9 30847
2003	96,439	86,515	0	$ 31,000	2.79085
2004	120.127	17,128	0	$ 133,998	0 12782
2005	114,895	46,658	0	$ 202.235	0.23071
2006	86,265	67,321	0	$ 221.179	0.30437
2007	102,370	125,647	0	$ 197,902	0.63489
2008	213,902	72.235	0	$ 339.569	0.21272
2009	317,874	36,696	0	$ 620.746	0.05912
2010	217.961	19.629	0	$ 819.078	0 02396
2011	217.912	0	0	$ 1.036.990	0.00000
TOTAL	$ 2,073.419	$ 4,216,554	$ -	$ 3.702,266	1.13891

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0 5	1.13891	(0 13891)	0.43054	(0.05249)
2011	1.5	1.13891	(0.13891)	(0.05981)	0.00729
2010	2.5	1.13891	(0.13891)	0.00831	(0.00101)
2009	3 5	1.13891	(0 13891)	(0 00115)	0.00014
2008	4.5	1.13891	(0 13891)	0 00016	(0 00002)
2007	5.5	1.13891	(0.13891)	(0.00002)	0.00000
2006	6.5	1.13891	(0 13891)	0.00000	(0.00000)
2005	7.5	1.13891	(0 13891)	(0.00000)	0.00000
2004	8 5	1.13891	(0.13891)	0.00000	(0.00000)
2003	9.5	1.13891	(0 13891)	(0 00000)	0.00000
2002	10.5	1.13891	(0.13891)	0 00000	(0 00000)
2001	11 5	1 13891	(0 13891)	(0.00000)	0 00000
2000	12 5	1 13891	(0.13891)	0 00000	(0 00000)
1999	13 5	1.13891	(0.13891)	(0 00000)	0.00000
1998	14 5	1.13891	(0 13891)	0 00000	(0 00000)
1997	15.5	1.13891	(0 13891)	(0.00000)	0.00000
1996	16.5	1 13891	(0.13891)	0.00000	(0 00000)
1995	17.5	1.13891	(0.13891)	(0 00000)	0.00000
1994	18 5	1.13891	(0 13891)	0 00000	(0 00000)
1993	19 5	1.13891	(0 13891)	(0.00000)	0 00000
1992	20 5	1.13891	(0.13891)	0.00000	(0 00000)
1991	21.5	1.13891	(0.13891)	(0.00000)	0.00000
1990	22.5	1.13891	(0.13891)	0.00000	(0 00000)
1989	23 5	1 13891	(0.13891)	(0 00000)	0 00000
1988	24.5	1.13891	(0 13891)	0 00000	(0.00000)
1987	25.5	1.13891	(0.13891)	(0.00000)	0.00000
1986	26.5	1 13891	(0 13891)	0 00000	(0.00000)
1985	27.5	1 13891	(0 13891)	(0 00000)	0.00000
1984	28 5	1.13891	(0 13891)	0 00000	(0 00000)
1983	29.5	1.13891	(0.13891)	(0.00000)	0 00000
1982	30.5	1.13891	(0 13891)	0.00000	(0.00000)
1981	31.5	1.13891	(0.13891)	(0.00000)	0 00000
1980	32 5	1.13891	(0.13891)	0 00000	(0.00000)
1979	33.5	1 13891	(0.13891)	(0 00000)	0 00000
1978	34.5	1 13891	(0 13891)	0 00	(0.00000)
1977	35 5	1 13891	(0 13891)	(0.00)	0.00000
1976	36 5	1 13891	(0 13891)	0.00	(0.00000)
1975	37.5	1.13891	(0 13891)	(0.00)	0.00000
1974	38 5	1 13891	(0.13891)	0.00	(0.00000)
1973	39.5	1 13891	(0.13891)	(0 00)	0.00000
1972	40 5	1.13891	(0 13891)	0.00	(0 00000)
1971	41 5	1 13891	(0 13891)	(0 00)	0.00000
1970	42.5	1 13891	(0 13891)	0.00	(0 00000)
1969	43.5	1 13891	(0 13891)	(0.00)	0 00000
1968	44.5	1 13891	(0 13891)	0 00	(0.00000)
1967	45 5	1 13891	(0.13891)	(0 00)	0.00000
1966	46.5	1.13891	(0 13891)	0 00	(0 00000)
1965	47 5	1.13891	(0.13891)	(0.00)	0 00000
1964	48 5	1 13891	(0 13891)	0.00	(0 00000)
1963	49.5	1 13891	(0.13891)	(0.00)	0 00000
1962	50 5	1 13891	(0 13891)	0 00	(0 00000)
1961	51 5	1 13891	(0 13891)	(0 00)	0.00000
1960	52 5	1 13891	(0 13891)	0	(0 00000)
1959	53 5	1.13891	(0 13891)	(0)	0.00000
1958	54.5	1.13891	(0.13891)	0	(0 00000)
1957	55.5	1.13891	(0.13891)	(0)	0 00000
1956	56.5	1 13891	(0.13891)	0	(0.00000)
1955	57 5	1 13891	(0 13891)	(0)	0.00000
1954	58 5	1.13891	(0.13891)	0	(0 00000)

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Burns & McDonnell SINCE 1898

General Plant Vehicles Transmission | Account: 392.3

Date of Retirement (Mid Year):	2017
Interim Retirement Rate:	0.10108
Study Date, Year-End:	2012
Future Life from Study Date:	5.0
Remaining Life (F/E + .5) =	4.7

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Adjustments and Transfers	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	0	0	0	$ -	0.00000
1966	0	0	0	$ -	0.00000
1967	0	0	0	$ -	0.00000
1968	0	0	0	$ -	0.00000
1969	0	0	0	$ -	0.00000
1970	0	0	0	$ -	0.00000
1971	0	0	0	$ -	0.00000
1972	0	0	0	$ -	0.00000
1973	13,937	0	0	$ 13,937	0.00000
1974	0	0	0	$ 13,937	0.00000
1975	0	0	0	$ 13,937	0.00000
1976	0	0	0	$ 13,937	0.00000
1977	0	0	0	$ 13,937	0.00000
1978	0	0	0	$ 13,937	0.00000
1979	0	0	0	$ 13,937	0.00000
1980	0	0	0	$ 13,937	0.00000
1981	3,000	0	0	$ 16,937	0.00000
1982	0	0	0	$ 16,937	0.00000
1983	0	49,639	0	$ -	0.00000
1984	0	0	0	$ -	0.00000
1985	0	0	0	$ -	0.00000
1986	0	0	0	$ -	0.00000
1987	0	0	0	$ -	0.00000
1988	0	0	0	$ -	0.00000
1989	105,435	0	0	$ 105,435	0.00000
1990	124,090	67,679	0	$ 161,846	0.41817
1991	30,236	6,228	0	$ 185,854	0.03351
1992	0	121,703	0	$ 64,151	1.89712
1993	29,592	5,000	0	$ 88,743	0.05634
1994	41,086	23,388	0	$ 106,442	0.21972
1995	0	12,865	0	$ 93,576	0.13749
1996	72,462	34,768	0	$ 131,270	0.26486
1997	0	0	0	$ 131,270	0.00000
1998	275,403	186,258	0	$ 220,415	0.84503
1999	0	0	0	$ 220,415	0.00000
2000	0	0	0	$ 220,415	0.00000
2001	32,404	0	0	$ 252,818	0.00000
2002	251,699	21,313	0	$ 483,204	0.04411
2003	0	150,672	0	$ 332,532	0.45311
2004	0	0	0	$ 332,532	0.00000
2005	2,268	0	0	$ 334,800	0.00000
2006	0	0	0	$ 334,800	0.00000
2007	0	0	0	$ 334,800	0.00000
2008	275,629	0	0	$ 610,430	0.00000
2009	0	0	0	$ 610,430	0.00000
2010	0	0	0	$ 610,430	0.00000
2011	0	0	0	$ 610,430	0.00000
TOTAL	$ 1,257,240	$ 679,512	$ -	$ 6,722,404	0.10108

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1 - C)	E	F
2012	0.5	0.10108	0.89892	0.94946	3.98855
2011	1.5	0.10108	0.89892	0.85349	3.58538
2010	2.5	0.10108	0.89892	0.76721	3.22297
2009	3.5	0.10108	0.89892	0.68966	2.89718
2008	4.5	0.10108	0.89892	0.61995	2.60433
2007	5.5	0.10108	0.89892	0.55729	2.34108
2006	6.5	0.10108	0.89892	0.50095	2.10444
2005	7.5	0.10108	0.89892	0.45032	1.89172
2004	8.5	0.10108	0.89892	0.40480	1.70050
2003	9.5	0.10108	0.89892	0.36388	1.52861
2002	10.5	0.10108	0.89892	0.32710	1.37410
2001	11.5	0.10108	0.89892	0.29403	1.23520
2000	12.5	0.10108	0.89892	0.26431	1.11035
1999	13.5	0.10108	0.89892	0.23760	0.99811
1998	14.5	0.10108	0.89892	0.21358	0.89722
1997	15.5	0.10108	0.89892	0.19199	0.80653
1996	16.5	0.10108	0.89892	0.17258	0.72500
1995	17.5	0.10108	0.89892	0.15514	0.65172
1994	18.5	0.10108	0.89892	0.13946	0.58584
1993	19.5	0.10108	0.89892	0.12536	0.52662
1992	20.5	0.10108	0.89892	0.11269	0.47339
1991	21.5	0.10108	0.89892	0.10130	0.42554
1990	22.5	0.10108	0.89892	0.09106	0.38253
1989	23.5	0.10108	0.89892	0.08185	0.34386
1988	24.5	0.10108	0.89892	0.07358	0.30910
1987	25.5	0.10108	0.89892	0.06614	0.27786
1986	26.5	0.10108	0.89892	0.05946	0.24977
1985	27.5	0.10108	0.89892	0.05345	0.22452
1984	28.5	0.10108	0.89892	0.04804	0.20183
1983	29.5	0.10108	0.89892	0.04319	0.18143
1982	30.5	0.10108	0.89892	0.03882	0.16309
1981	31.5	0.10108	0.89892	0.03490	0.14660
1980	32.5	0.10108	0.89892	0.03137	0.13178
1979	33.5	0.10108	0.89892	0.02820	0.11846
1978	34.5	0.10108	0.89892	0.02535	0.10649
1977	35.5	0.10108	0.89892	0.02279	0.09572
1976	36.5	0.10108	0.89892	0.02048	0.08605
1975	37.5	0.10108	0.89892	0.01841	0.07735
1974	38.5	0.10108	0.89892	0.01655	0.06953
1973	39.5	0.10108	0.89892	0.01488	0.06250
1972	40.5	0.10108	0.89892	0.01337	0.05619
1971	41.5	0.10108	0.89892	0.01202	0.05051
1970	42.5	0.10108	0.89892	0.01081	0.04540
1969	43.5	0.10108	0.89892	0.00972	0.04081
1968	44.5	0.10108	0.89892	0.00873	0.03669
1967	45.5	0.10108	0.89892	0.00785	0.03298
1966	46.5	0.10108	0.89892	0.00706	0.02964
1965	47.5	0.10108	0.89892	0.00634	0.02665
1964	48.5	0.10108	0.89892	0.00570	0.02395
1963	49.5	0.10108	0.89892	0.00513	0.02153
1962	50.5	0.10108	0.89892	0.00461	0.01936
1961	51.5	0.10108	0.89892	0.00414	0.01740
1960	52.5	0.10108	0.89892	0.00372	0.01564
1959	53.5	0.10108	0.89892	0.00335	0.01406
1958	54.5	0.10108	0.89892	0.00301	0.01105
1957	55.5	0.10108	0.89892	0.00270	0.00835
1956	56.5	0.10108	0.89892	0.00243	0.00592
1955	57.5	0.10108	0.89892	0.00219	0.00373
1954	58.5	0.10108	0.89892	0.00196	0.00177

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

General Plant Stores Equipment | Account: 393

Date of Retirement (Mid Year):	2020
Interim Retirement Rate:	0.13235
Study Date. Year-End:	2012
Future Life from Study Date:	8.0
Remaining Life (F/E + .5) =	5.2

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Removal Costs	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	0	0	0	$ -	0.00000
1966	0	0	0	$ -	0.00000
1967	0	0	0	$ -	0.00000
1968	0	0	0	$ -	0.00000
1969	0	0	0	$ -	0.00000
1970	0	0	0	$ -	0.00000
1971	0	0	0	$ -	0.00000
1972	0	0	0	$ -	0.00000
1973	0	0	0	$ -	0.00000
1974	0	0	0	$ -	0.00000
1975	0	0	0	$ -	0.00000
1976	0	0	0	$ -	0.00000
1977	0	0	0	$ -	0.00000
1978	0	0	0	$ -	0.00000
1979	15,170	0	0	$ 15,170	0.00000
1980	2,649	0	0	$ 17,818	0.00000
1981	1,481	0	0	$ 19,299	0.00000
1982	0	0	0	$ 19,299	0.00000
1983	1,449	0	0	$ 20,748	0.00000
1984	1,345	0	0	$ 22,093	0.00000
1985	15,937	0	0	$ 38,030	0.00000
1986	1,941	0	0	$ 39,970	0.00000
1987	509	0	0	$ 40,480	0.00000
1988	0	0	0	$ 40,480	0.00000
1989	0	0	0	$ 40,480	0.00000
1990	6,710	0	0	$ 47,190	0.00000
1991	5,603	0	0	$ 52,793	0.00000
1992	1,879	621	0	$ 54,052	0.01148
1993	0	0	0	$ 54,052	0.00000
1994	0	491	0	$ 53,561	0.00916
1995	0	0	0	$ 53,561	0.00000
1996	0	0	0	$ 53,561	0.00000
1997	3,677	0	0	$ 57,239	0.00000
1998	0	92,770	0	$ -	0.00000
1999	1,831	0	0	$ 1,831	0.00000
2000	36,692	24,692	0	$ 13,831	1.78532
2001	0	1,245	0	$ 12,586	0.09890
2002	0	0	0	$ 12,586	0.00000
2003	0	0	0	$ 12,586	0.00000
2004	0	0	0	$ 12,586	0.00000
2005	0	0	0	$ 12,586	0.00000
2006	1,893	0	0	$ 14,479	0.00000
2007	0	0	0	$ 14,479	0.00000
2008	0	0	0	$ 14,479	0.00000
2009	0	0	0	$ 14,479	0.00000
2010	0	0	0	$ 14,479	0.00000
2011	0	0	0	$ 14,479	0.00000
TOTAL	$ 98,766	$ 119,819	$ -	$ 905,341	0.13235

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0.5	0.13235	0.86765	0.93383	4.41594
2011	1.5	0.13235	0.86765	0.81024	3.83151
2010	2.5	0.13235	0.86765	0.70301	3.32442
2009	3.5	0.13235	0.86765	0.60997	2.88445
2008	4.5	0.13235	0.86765	0.52924	2.50270
2007	5.5	0.13235	0.86765	0.45920	2.17148
2006	6.5	0.13235	0.86765	0.39842	1.88409
2005	7.5	0.13235	0.86765	0.34569	1.63473
2004	8.5	0.13235	0.86765	0.29994	1.41838
2003	9.5	0.13235	0.86765	0.26025	1.23067
2002	10.5	0.13235	0.86765	0.22580	1.06779
2001	11.5	0.13235	0.86765	0.19592	0.92647
2000	12.5	0.13235	0.86765	0.16999	0.80386
1999	13.5	0.13235	0.86765	0.14749	0.69747
1998	14.5	0.13235	0.86765	0.12797	0.60516
1997	15.5	0.13235	0.86765	0.11104	0.52507
1996	16.5	0.13235	0.86765	0.09634	0.45558
1995	17.5	0.13235	0.86765	0.08359	0.39528
1994	18.5	0.13235	0.86765	0.07253	0.34297
1993	19.5	0.13235	0.86765	0.06293	0.29758
1992	20.5	0.13235	0.86765	0.05460	0.25820
1991	21.5	0.13235	0.86765	0.04737	0.22402
1990	22.5	0.13235	0.86765	0.04110	0.19438
1989	23.5	0.13235	0.86765	0.03566	0.16865
1988	24.5	0.13235	0.86765	0.03094	0.14633
1987	25.5	0.13235	0.86765	0.02685	0.12696
1986	26.5	0.13235	0.86765	0.02330	0.11016
1985	27.5	0.13235	0.86765	0.02021	0.09558
1984	28.5	0.13235	0.86765	0.01754	0.08293
1983	29.5	0.13235	0.86765	0.01522	0.07196
1982	30.5	0.13235	0.86765	0.01320	0.06243
1981	31.5	0.13235	0.86765	0.01146	0.05417
1980	32.5	0.13235	0.86765	0.00994	0.04700
1979	33.5	0.13235	0.86765	0.00862	0.04078
1978	34.5	0.13235	0.86765	0.00748	0.03538
1977	35.5	0.13235	0.86765	0.00649	0.03070
1976	36.5	0.13235	0.86765	0.00563	0.02664
1975	37.5	0.13235	0.86765	0.00489	0.02311
1974	38.5	0.13235	0.86765	0.00424	0.02005
1973	39.5	0.13235	0.86765	0.00368	0.01740
1972	40.5	0.13235	0.86765	0.00319	0.01510
1971	41.5	0.13235	0.86765	0.00277	0.01310
1970	42.5	0.13235	0.86765	0.00240	0.01136
1969	43.5	0.13235	0.86765	0.00209	0.00986
1968	44.5	0.13235	0.86765	0.00181	0.00856
1967	45.5	0.13235	0.86765	0.00157	0.00742
1966	46.5	0.13235	0.86765	0.00136	0.00644
1965	47.5	0.13235	0.86765	0.00118	0.00559
1964	48.5	0.13235	0.86765	0.00103	0.00485
1963	49.5	0.13235	0.86765	0.00089	0.00421
1962	50.5	0.13235	0.86765	0.00077	0.00365
1961	51.5	0.13235	0.86765	0.00067	0.00298
1960	52.5	0.13235	0.86765	0.00058	0.00240
1959	53.5	0.13235	0.86765	0.00050	0.00190
1958	54.5	0.13235	0.86765	0.00044	0.00146
1957	55.5	0.13235	0.86765	0.00038	0.00108
1956	56.5	0.13235	0.86765	0.00033	0.00075
1955	57.5	0.13235	0.86765	0.00029	0.00046
1954	58.5	0.13235	0.86765	0.00025	0.00022

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

General Plant Tools　　Account: 394

Date of Retirement (Mid Year): 2020
Interim Retirement Rate: 0 03107
Study Date, Year-End: 2012
Future Life from Study Date: 8 0
Remaining Life (F/E + .5) = 8 2

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Removal Costs	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0 00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0 00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	0	0	0	$ -	0.00000
1966	0	0	0	$ -	0.00000
1967	2,350	0	0	$ 2,350	0.00000
1968	555	0	0	$ 2,905	0 00000
1969	0	0	0	$ 2.905	0.00000
1970	4.742	0	0	$ 7.647	0 00000
1971	3.825	475	0	$ 10,996	0.04323
1972	0	0	0	$ 10,996	0.00000
1973	601	0	0	$ 11,598	0 00000
1974	1,347	0	0	$ 12,945	0.00000
1975	0	0	0	$ 12,945	0:00000
1976	0	0	0	$ 12.945	0 00000
1977	3,148	0	0	$ 16,093	0 00000
1978	82,823	0	0	$ 98.916	0 00000
1979	6,795	232	0	$ 105.479	0 00220
1980	35,977	0	0	$ 141,456	0 00000
1981	16,713	425	0	$ 157.744	0.00269
1982	11,694	0	0	$ 169,437	0.00000
1983	2,687	3,735	0	$ 168,390	0 02218
1984	29,870	1.809	0	$ 196.451	0 00921
1985	5,993	2,334	0	$ 200.110	0 01166
1986	5.411	239	0	$ 205,282	0.00117
1987	0	568	0	$ 204.714	0.00277
1988	27,022	3,788	0	$ 227,948	0 01662
1989	6,594	577	0	$ 233.965	0 00247
1990	10,719	446	0	$ 244,238	0 00183
1991	4,753	29,508	0	$ 219,484	0 13444
1992	19,516	18,406	0	$ 220.594	0 08344
1993	6,322	6,085	0	$ 220 831	0.02755
1994	7.847	27,018	0	$ 201,660	0 13398
1995	5,453	3.774	0	$ 203,340	0 01856
1996	14,754	1,224	0	$ 216.869	0 00564
1997	30,127	513	0	$ 246,484	0 00208
1998	9,111	80,060	0	$ 175.534	0 45609
1999	4,843	4.340	0	$ 176,037	0 02466
2000	13.183	8,063	0	$ 181,158	0 04451
2001	12,247	31,571	0	$ 161,833	0 19508
2002	8,375	0	0	$ 170,208	0.00000
2003	6,007	537	0	$ 175,679	0 00305
2004	9,238	0	0	$ 184,917	0 00000
2005	5,911	1,299	0	$ 189,529	0 00685
2006	2,300	3,357	0	$ 188.473	0.01781
2007	14,993	7,646	0	$ 195,819	0 03905
2008	275,416	625	0	$ 470,610	0.00133
2009	7,349	0	0	$ 477,959	0 00000
2010	6,216	753	0	$ 483.423	0 00156
2011	2.439	0	0	$ 485.862	0 00000
TOTAL	$ 725.269	$ 239,407	$ -	$ 7,704,758	0.03107

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0.5	0.03107	0.96893	0.98446	7 59171
2011	1.5	0 03107	0.96893	0.95387	7 35582
2010	2.5	0.03107	0.96893	0.92423	7 12725
2009	3.5	0.03107	0 96893	0.89552	6 90579
2008	4.5	0 03107	0.96893	0 86769	6.69121
2007	5.5	0.03107	0.96893	0 84073	6.48330
2006	6.5	0.03107	0.96893	0.81461	6.28184
2005	7.5	0.03107	0.96893	0 78929	6.08665
2004	8.5	0.03107	0.96893	0.76477	5 89752
2003	9 5	0.03107	0.96893	0 74100	5.71427
2002	10.5	0.03107	0.96893	0 71798	5 53671
2001	11.5	0.03107	0 96893	0 69567	5.36467
2000	12 5	0.03107	0 96893	0 67405	5 19798
1999	13.5	0.03107	0.96893	0.65311	5 03646
1998	14.5	0.03107	0.96893	0 63282	4.87997
1997	15.5	0.03107	0.96893	0.61315	4 72833
1996	16 5	0.03107	0.96893	0.59410	4 58141
1995	17 5	0.03107	0.96893	0 57564	4.43906
1994	18 5	0 03107	0.96893	0.55775	4 30112
1993	19.5	0.03107	0.96893	0.54042	4 16748
1992	20.5	0.03107	0.96893	0.52363	4 03798
1991	21 5	0.03107	0.96893	0 50736	3.91251
1990	22 5	0.03107	0.96893	0 49159	3 79094
1989	23.5	0.03107	0 96893	0 47632	3.67314
1988	24.5	0.03107	0.96893	0.46152	3 55901
1987	25 5	0.03107	0.96893	0.44718	3.44842
1986	26 5	0.03107	0 96893	0.43328	3.34127
1985	27.5	0 03107	0.96893	0 41982	3 23745
1984	28.5	0.03107	0.96893	0.40677	3 13685
1983	29 5	0.03107	0.96893	0 39414	3 03938
1982	30 5	0.03107	0.96893	0.38189	2.94494
1981	31.5	0 03107	0.96893	0.37002	2 85343
1980	32 5	0.03107	0.96893	0 35852	2 76477
1979	33 5	0.03107	0.96893	0 34738	2.67886
1978	34.5	0.03107	0 96893	0.33659	2.59562
1977	35 5	0 03107	0 96893	0 32613	2 51497
1976	36 5	0 03107	0.96893	0 31600	2.43682
1975	37 5	0.03107	0 96893	0.30618	2.36110
1974	38.5	0 03107	0 96893	0 29667	2.28774
1973	39.5	0.03107	0.96893	0 28745	2.21665
1972	40 5	0.03107	0.96893	0.27852	2 14778
1971	41 5	0.03107	0 96893	0.26986	2 08104
1970	42.5	0.03107	0.96893	0.26148	2 01638
1969	43 5	0 03107	0.96893	0.25335	1.95372
1968	44 5	0.03107	0.96893	0.24548	1 89301
1967	45 5	0.03107	0.96893	0.23785	1.83419
1966	46.5	0 03107	0.96893	0.23046	1 77720
1965	47.5	0.03107	0 96893	0.22330	1 72198
1964	48.5	0 03107	0 96893	0.21636	1.66847
1963	49.5	0.03107	0.96893	0.20964	1.61663
1962	50.5	0.03107	0.96893	0.20312	1 56639
1961	51 5	0.03107	0.96893	0 19681	1.36958
1960	52.5	0 03107	0 96893	0 19070	1.17889
1959	53.5	0.03107	0 96893	0.18477	0.99411
1958	54.5	0.03107	0.96893	0 17903	0.81508
1957	55.5	0.03107	0.96893	0.17347	0.64162
1956	56 5	0.03107	0.96893	0 16808	0.47354
1955	57 5	0 03107	0 96893	0 16285	0.31069
1954	58.5	0.03107	0.96893	0 15779	0 15289

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

General Plant Lab Equipment — Account: 395

Date of Retirement (Mid Year):	2020
Interim Retirement Rate:	0 12220
Study Date, Year-End:	2012
Future Life from Study Date:	8 0
Remaining Life (F/E + 5) =	5.7

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Removal Costs	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0 00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0 00000
1957	0	0	0	$ -	0 00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0 00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0 00000
1964	0	0	0	$ -	0 00000
1965	0	0	0	$ -	0 00000
1966	762	0	0	$ 762	0 00000
1967	9,649	0	0	$ 10.411	0.00000
1968	4,998	0	0	$ 15.409	0.00000
1969	0	0	0	$ 15.409	0.00000
1970	4.382	0	0	$ 19.791	0.00000
1971	2.381	0	0	$ 22.172	0 00000
1972	1,822	0	0	$ 23.994	0 00000
1973	921	0	0	$ 24,915	0.00000
1974	7,646	252	0	$ 32,308	0 00781
1975	6.189	0	0	$ 38,497	0 00000
1976	0	0	0	$ 38,497	0 00000
1977	977	0	0	$ 39,474	0.00000
1978	1,304	0	0	$ 40,778	0 00000
1979	13.537	0	0	$ 54,314	0 00000
1980	593	0	0	$ 54.908	0 00000
1981	5,084	0	0	$ 59.991	0 00000
1982	13,273	675	0	$ 72,590	0 00930
1983	7.025	0	0	$ 79.614	0.00000
1984	0	0	0	$ 79,614	0.00000
1985	0	0	0	$ 79,614	0.00000
1986	0	0	0	$ 79.614	0.00000
1987	0	0	0	$ 79,614	0 00000
1988	0	694	0	$ 78,920	0.00879
1989	14,936	0	0	$ 93,856	0 00000
1990	5,191	0	0	$ 99.047	0 00000
1991	35,538	0	0	$ 134,585	0 00000
1992	5,548	0	0	$ 140,134	0 00000
1993	4.918	14,116	0	$ 130,936	0 10781
1994	0	17.089	0	$ 113,847	0 15011
1995	0	0	0	$ 113,847	0.00000
1996	3.517	646	0	$ 116,718	0.00553
1997	4,915	2,817	0	$ 118.816	0.02371
1998	0	138,121	0	$ -	0.00000
1999	0	132,253	0	$ -	0 00000
2000	0	0	0	$ -	0.00000
2001	0	20,237	0	$ -	0.00000
2002	32.841	1.015	0	$ 31,826	0.03189
2003	0	-7.912	0	$ 39,738	-0 19910
2004	0	0	0	$ 39.738	0.00000
2005	0	0	0	$ 39.738	0 00000
2006	33.333	5,205	0	$ 67,865	0.07670
2007	0	0	0	$ 67,865	0.00000
2008	0	0	0	$ 67.865	0 00000
2009	0	0	0	$ 67.865	0 00000
2010	0	0	0	$ 67.865	0 00000
2011	0	0	0	$ 67,865	0.00000
TOTAL	$ 221,279	$ 325,207	$ -	$ 2,661,229	0.12220

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0 5	0 12220	0.87780	0 93890	4 91246
2011	1.5	0 12220	0 87780	0.82416	4.31215
2010	2.5	0.12220	0.87780	0 72345	3 78520
2009	3 5	0 12220	0.87780	0 63504	3.32264
2008	4.5	0.12220	0.87780	0.55744	2.91661
2007	5.5	0 12220	0.87780	0 48932	2 56019
2006	6 5	0.12220	0.87780	0.42952	2 24733
2005	7 5	0.12220	0 87780	0 37703	1 97270
2004	8.5	0.12220	0 87780	0 33096	1 73164
2003	9.5	0.12220	0.87780	0 29052	1 52003
2002	10.5	0 12220	0 87780	0.25501	1.33428
2001	11.5	0.12220	0.87780	0.22385	1 17123
2000	12 5	0 12220	0.87780	0 19650	1.02810
1999	13 5	0.12220	0.87780	0.17248	0.90246
1998	14.5	0 12220	0.87780	0.15141	0 79218
1997	15 5	0.12220	0.87780	0 13290	0.69538
1996	16.5	0.12220	0.87780	0 11666	0.61040
1995	17.5	0.12220	0.87780	0 10241	0 53581
1994	18 5	0 12220	0.87780	0 08989	0 47033
1993	19.5	0 12220	0.87780	0.07891	0.41286
1992	20.5	0 12220	0 87780	0.06926	0.36240
1991	21.5	0.12220	0 87780	0 06080	0 31812
1990	22.5	0.12220	0.87780	0.05337	0 27924
1989	23 5	0 12220	0.87780	0.04685	0.24512
1988	24 5	0 12220	0.87780	0.04112	0.21516
1987	25 5	0 12220	0.87780	0.03610	0 18887
1986	26 5	0.12220	0 87780	0.03169	0.16579
1985	27.5	0.12220	0 87780	0 02781	0.14553
1984	28.5	0.12220	0 87780	0 02442	0.12775
1983	29 5	0.12220	0.87780	0 02143	0.11214
1982	30.5	0.12220	0.87780	0 01881	0 09843
1981	31.5	0.12220	0.87780	0 01651	0 08640
1980	32 5	0.12220	0.87780	0.01450	0 07585
1979	33.5	0 12220	0.87780	0.01272	0 06658
1978	34 5	0 12220	0 87780	0 01117	0.05844
1977	35 5	0.12220	0 87780	0 00980	0.05130
1976	36.5	0 12220	0 87780	0.00861	0.04503
1975	37 5	0.12220	0.87780	0.00755	0 03953
1974	38 5	0 12220	0 87780	0.00663	0.03470
1973	39.5	0 12220	0.87780	0 00582	0.03046
1972	40 5	0.12220	0.87780	0 00511	0.02674
1971	41.5	0 12220	0.87780	0 00449	0.02347
1970	42.5	0.12220	0.87780	0.00394	0 02060
1969	43.5	0.12220	0.87780	0 00346	0 01808
1968	44.5	0.12220	0 87780	0.00303	0.01587
1967	45.5	0.12220	0 87780	0.00266	0 01393
1966	46.5	0 12220	0.87780	0.00234	0 01223
1965	47.5	0 12220	0.87780	0.00205	0 01074
1964	48.5	0 12220	0 87780	0 00180	0 00942
1963	49 5	0.12220	0 87780	0.00158	0 00827
1962	50 5	0.12220	0 87780	0.00139	0 00688
1961	51.5	0.12220	0 87780	0.00122	0 00567
1960	52 5	0.12220	0 87780	0.00107	0 00460
1959	53 5	0.12220	0.87780	0 00094	0.00366
1958	54.5	0.12220	0.87780	0 00082	0.00283
1957	55.5	0 12220	0 87780	0 00072	0.00211
1956	56 5	0.12220	0 87780	0.00063	0 00148
1955	57 5	0 12220	0.87780	0 00056	0 00092
1954	58 5	0.12220	0.87780	0.00049	0.00043

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Burns & McDonnell SINCE 1898

General Plant Power Operated Eqpt — Account: 396

Date of Retirement (Mid Year):	2021
Interim Retirement Rate:	0.13552
Study Date. Year-End:	2012
Future Life from Study Date:	9.0
Remaining Life (F/E + .5) =	5.6

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Removal Costs	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	0	0	0	$ -	0.00000
1966	0	0	0	$ -	0.00000
1967	0	0	0	$ -	0.00000
1968	0	0	0	$ -	0.00000
1969	0	0	0	$ -	0.00000
1970	0	0	0	$ -	0.00000
1971	0	0	0	$ -	0.00000
1972	0	0	0	$ -	0.00000
1973	0	0	0	$ -	0.00000
1974	0	0	0	$ -	0.00000
1975	0	0	0	$ -	0.00000
1976	0	0	0	$ -	0.00000
1977	0	0	0	$ -	0.00000
1978	0	0	0	$ -	0.00000
1979	561	0	0	$ 561	0.00000
1980	0	37,557	0	$ -	0.00000
1981	117,498	0	0	$ 117,498	0.00000
1982	14,401	0	0	$ 131,899	0.00000
1983	0	0	0	$ 131,899	0.00000
1984	0	0	0	$ 131,899	0.00000
1985	0	0	0	$ 131,899	0.00000
1986	0	0	0	$ 131,899	0.00000
1987	85,838	29,478	0	$ 188,259	0.15658
1988	0	38,931	0	$ 149,328	0.26071
1989	2,063	6,017	0	$ 145,374	0.04139
1990	0	0	0	$ 145,374	0.00000
1991	0	44,939	0	$ 100,435	0.44744
1992	17,923	12,896	0	$ 105,462	0.12228
1993	0	0	0	$ 105,462	0.00000
1994	57,527	25,413	0	$ 137,577	0.18472
1995	0	0	0	$ 137,577	0.00000
1996	7,036	5,314	0	$ 139,298	0.03815
1997	19,536	124,795	0	$ 34,040	3.66616
1998	64,553	62,951	0	$ 35,641	1.76625
1999	4,277	0	0	$ 39,919	0.00000
2000	0	530	0	$ 39,389	0.01346
2001	7,192	388	0	$ 46,192	0.00841
2002	0	0	0	$ 46,192	0.00000
2003	19,528	7,084	0	$ 58,636	0.12082
2004	44,979	32,447	0	$ 71,168	0.45592
2005	19,804	11,613	0	$ 79,359	0.14633
2006	0	0	0	$ 79,359	0.00000
2007	9,909	0	0	$ 89,268	0.00000
2008	12,114	0	0	$ 101,383	0.00000
2009	0	0	0	$ 101,383	0.00000
2010	29,842	0	0	$ 131,225	0.00000
2011	33,294	0	0	$ 164,519	0.00000
TOTAL	$ 567,875	$ 440,353	$ -	$ 3,249,370	0.13552

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0.5	0.13552	0.86448	0.93224	4.74841
2011	1.5	0.13552	0.86448	0.80590	4.10491
2010	2.5	0.13552	0.86448	0.69669	3.54861
2009	3.5	0.13552	0.86448	0.60227	3.06771
2008	4.5	0.13552	0.86448	0.52065	2.65197
2007	5.5	0.13552	0.86448	0.45009	2.29258
2006	6.5	0.13552	0.86448	0.38910	1.98189
2005	7.5	0.13552	0.86448	0.33637	1.71331
2004	8.5	0.13552	0.86448	0.29078	1.48112
2003	9.5	0.13552	0.86448	0.25138	1.28040
2002	10.5	0.13552	0.86448	0.21731	1.10688
2001	11.5	0.13552	0.86448	0.18786	0.95688
2000	12.5	0.13552	0.86448	0.16240	0.82720
1999	13.5	0.13552	0.86448	0.14039	0.71510
1998	14.5	0.13552	0.86448	0.12137	0.61819
1997	15.5	0.13552	0.86448	0.10492	0.53441
1996	16.5	0.13552	0.86448	0.09070	0.46199
1995	17.5	0.13552	0.86448	0.07841	0.39938
1994	18.5	0.13552	0.86448	0.06778	0.34526
1993	19.5	0.13552	0.86448	0.05860	0.29847
1992	20.5	0.13552	0.86448	0.05066	0.25802
1991	21.5	0.13552	0.86448	0.04379	0.22305
1990	22.5	0.13552	0.86448	0.03786	0.19282
1989	23.5	0.13552	0.86448	0.03273	0.16669
1988	24.5	0.13552	0.86448	0.02829	0.14410
1987	25.5	0.13552	0.86448	0.02446	0.12457
1986	26.5	0.13552	0.86448	0.02114	0.10769
1985	27.5	0.13552	0.86448	0.01828	0.09310
1984	28.5	0.13552	0.86448	0.01580	0.08048
1983	29.5	0.13552	0.86448	0.01366	0.06957
1982	30.5	0.13552	0.86448	0.01181	0.06015
1981	31.5	0.13552	0.86448	0.01021	0.05199
1980	32.5	0.13552	0.86448	0.00882	0.04495
1979	33.5	0.13552	0.86448	0.00763	0.03886
1978	34.5	0.13552	0.86448	0.00659	0.03359
1977	35.5	0.13552	0.86448	0.00570	0.02904
1976	36.5	0.13552	0.86448	0.00493	0.02510
1975	37.5	0.13552	0.86448	0.00426	0.02170
1974	38.5	0.13552	0.86448	0.00368	0.01876
1973	39.5	0.13552	0.86448	0.00318	0.01622
1972	40.5	0.13552	0.86448	0.00275	0.01402
1971	41.5	0.13552	0.86448	0.00238	0.01212
1970	42.5	0.13552	0.86448	0.00206	0.01048
1969	43.5	0.13552	0.86448	0.00178	0.00906
1968	44.5	0.13552	0.86448	0.00154	0.00783
1967	45.5	0.13552	0.86448	0.00133	0.00677
1966	46.5	0.13552	0.86448	0.00115	0.00585
1965	47.5	0.13552	0.86448	0.00099	0.00506
1964	48.5	0.13552	0.86448	0.00086	0.00437
1963	49.5	0.13552	0.86448	0.00074	0.00363
1962	50.5	0.13552	0.86448	0.00064	0.00299
1961	51.5	0.13552	0.86448	0.00055	0.00243
1960	52.5	0.13552	0.86448	0.00048	0.00196
1959	53.5	0.13552	0.86448	0.00041	0.00154
1958	54.5	0.13552	0.86448	0.00036	0.00118
1957	55.5	0.13552	0.86448	0.00031	0.00087
1956	56.5	0.13552	0.86448	0.00027	0.00060
1955	57.5	0.13552	0.86448	0.00023	0.00037
1954	58.5	0.13552	0.86448	0.00020	0.00017

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Burns & McDonnell SINCE 1898

General Plant Communication Eqpt   Account: 397

Date of Retirement (Mid Year):	2013
Interim Retirement Rate:	0.08490
Study Date, Year-End:	2012
Future Life from Study Date:	1.0
Remaining Life (F/E + .5) =	2.3

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Removal Costs	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	0	0	0	$ -	0.00000
1966	0	0	0	$ -	0.00000
1967	0	0	0	$ -	0.00000
1968	0	0	2.048	$ 2,048	0.00000
1969	3,371	0	0	$ 5,419	0.00000
1970	1.877	0	0	$ 7,297	0.00000
1971	0	0	0	$ 7,297	0.00000
1972	0	0	0	$ 7.297	0.00000
1973	4.032	0	0	$ 11,328	0.00000
1974	0	0	0	$ 11.328	0.00000
1975	0	71	0	$ 11,258	0.00628
1976	2.894	0	0	$ 14.151	0.00000
1977	0	0	0	$ 14,151	0.00000
1978	0	0	0	$ 14,151	0.00000
1979	912	0	224	$ 15,287	0.00000
1980	0	0	664	$ 15,952	0.00000
1981	849	0	0	$ 16,800	0.00000
1982	2,691	0	38	$ 19,529	0.00000
1983	50,210	14,240	0	$ 55,499	0.25659
1984	4,045	3,170	0	$ 56,374	0.05624
1985	1.015,588	56,760	10.300	$ 1.025.501	0.05535
1986	26,172	4.629	0	$ 1,047,045	0.00442
1987	10.746	0	0	$ 1.057,790	0.00000
1988	27,796	2.626	0	$ 1.082.960	0.00242
1989	22,530	7.684	0	$ 1.097.806	0.00700
1990	12,921	11,575	0	$ 1.099.152	0.01053
1991	27,050	0	0	$ 1.126.202	0.00000
1992	23,027	1.313	0	$ 1.147,916	0.00114
1993	3,264	5,719	0	$ 1,145.461	0.00499
1994	167,081	227,774	0	$ 1.084,768	0.20997
1995	1,694	0	0	$ 1,086.462	0.00000
1996	7,030	3,443	0	$ 1.090,048	0.00316
1997	387	0	0	$ 1,090.435	0.00000
1998	23,421	784,830	0	$ 329,026	2.38531
1999	0	1,129	0	$ 327,897	0.00344
2000	0	56,972	0	$ 270.925	0.21029
2001	0	32,765	0	$ 238.159	0.13758
2002	0	2.933	0	$ 235,227	0.01247
2003	3.864	0	0	$ 239,091	0.00000
2004	3,888	0	0	$ 242,979	0.00000
2005	30,946	26.936	0	$ 246.989	0.10906
2006	157,096	57,985	0	$ 346.101	0.16754
2007	2,950	50.509	0	$ 298,542	0.16919
2008	1.106	0	0	$ 299,648	0.00000
2009	0	0	0	$ 299.648	0.00000
2010	682	0	0	$ 300.330	0.00000
2011	245.695	215.263	0	$ 330.762	0.65081
TOTAL	$ 1,885,814	$ 1,566,327	$ 13,274	$ 18,472,037	0.08490

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0.5	0.08490	0.91510	0.95755	1.67810
2011	1.5	0.08490	0.91510	0.87625	1.53563
2010	2.5	0.08490	0.91510	0.80185	1.40525
2009	3.5	0.08490	0.91510	0.73377	1.28594
2008	4.5	0.08490	0.91510	0.67148	1.17676
2007	5.5	0.08490	0.91510	0.61446	1.07685
2006	6.5	0.08490	0.91510	0.56230	0.98542
2005	7.5	0.08490	0.91510	0.51455	0.90176
2004	8.5	0.08490	0.91510	0.47087	0.82520
2003	9.5	0.08490	0.91510	0.43089	0.75513
2002	10.5	0.08490	0.91510	0.39431	0.69102
2001	11.5	0.08490	0.91510	0.36083	0.63235
2000	12.5	0.08490	0.91510	0.33019	0.57866
1999	13.5	0.08490	0.91510	0.30216	0.52953
1998	14.5	0.08490	0.91510	0.27650	0.48457
1997	15.5	0.08490	0.91510	0.25303	0.44343
1996	16.5	0.08490	0.91510	0.23155	0.40578
1995	17.5	0.08490	0.91510	0.21189	0.37133
1994	18.5	0.08490	0.91510	0.19390	0.33980
1993	19.5	0.08490	0.91510	0.17743	0.31095
1992	20.5	0.08490	0.91510	0.16237	0.28455
1991	21.5	0.08490	0.91510	0.14858	0.26039
1990	22.5	0.08490	0.91510	0.13597	0.23829
1989	23.5	0.08490	0.91510	0.12443	0.21805
1988	24.5	0.08490	0.91510	0.11386	0.19954
1987	25.5	0.08490	0.91510	0.10419	0.18260
1986	26.5	0.08490	0.91510	0.09535	0.16710
1985	27.5	0.08490	0.91510	0.08725	0.15291
1984	28.5	0.08490	0.91510	0.07984	0.13993
1983	29.5	0.08490	0.91510	0.07307	0.12805
1982	30.5	0.08490	0.91510	0.06686	0.11718
1981	31.5	0.08490	0.91510	0.06119	0.10723
1980	32.5	0.08490	0.91510	0.05599	0.09812
1979	33.5	0.08490	0.91510	0.05124	0.08979
1978	34.5	0.08490	0.91510	0.04689	0.08217
1977	35.5	0.08490	0.91510	0.04291	0.07519
1976	36.5	0.08490	0.91510	0.03926	0.06881
1975	37.5	0.08490	0.91510	0.03593	0.06297
1974	38.5	0.08490	0.91510	0.03288	0.05762
1973	39.5	0.08490	0.91510	0.03009	0.05273
1972	40.5	0.08490	0.91510	0.02753	0.04825
1971	41.5	0.08490	0.91510	0.02520	0.04415
1970	42.5	0.08490	0.91510	0.02306	0.04041
1969	43.5	0.08490	0.91510	0.02110	0.03698
1968	44.5	0.08490	0.91510	0.01931	0.03384
1967	45.5	0.08490	0.91510	0.01767	0.03096
1966	46.5	0.08490	0.91510	0.01617	0.02833
1965	47.5	0.08490	0.91510	0.01480	0.02593
1964	48.5	0.08490	0.91510	0.01354	0.02373
1963	49.5	0.08490	0.91510	0.01239	0.02171
1962	50.5	0.08490	0.91510	0.01134	0.01987
1961	51.5	0.08490	0.91510	0.01038	0.01818
1960	52.5	0.08490	0.91510	0.00949	0.01664
1959	53.5	0.08490	0.91510	0.00869	0.01523
1958	54.5	0.08490	0.91510	0.00795	0.01393
1957	55.5	0.08490	0.91510	0.00728	0.01275
1956	56.5	0.08490	0.91510	0.00666	0.01167
1955	57.5	0.08490	0.91510	0.00609	0.01068
1954	58.5	0.08490	0.91510	0.00558	0.00510

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Burns & McDonnell SINCE 1898

General Plant Miscellaneous Eqpt | Account: 398

Date of Retirement (Mid Year):	2021
Interim Retirement Rate:	0 24188
Study Date, Year-End:	2012
Future Life from Study Date:	9 0
Remaining Life (F/E + .5) =	3 5

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Removal Costs	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	0	0	0	$ -	0.00000
1966	0	0	0	$ -	0.00000
1967	0	0	0	$ -	0.00000
1968	0	0	0	$ -	0.00000
1969	0	0	0	$ -	0.00000
1970	0	0	0	$ -	0.00000
1971	0	0	0	$ -	0.00000
1972	0	0	0	$ -	0.00000
1973	0	0	0	$ -	0.00000
1974	0	2,056	0	$ -	0.00000
1975	0	0	0	$ -	0.00000
1976	0	232	0	$ -	0.00000
1977	0	0	0	$ -	0.00000
1978	0	0	0	$ -	0.00000
1979	6.745	1,619	0	$ 5,127	0 31571
1980	0	0	0	$ 5,127	0.00000
1981	3.777	3,120	171	$ 5,955	0.52381
1982	0	358	0	$ 5.597	0.06394
1983	629	10,640	0	$ -	0.00000
1984	0	0	0	$ -	0.00000
1985	0	27.811	0	$ -	0.00000
1986	0	10,942	0	$ -	0 00000
1987	0	7.871	0	$ -	0.00000
1988	0	6.016	0	$ -	0 00000
1989	0	9,363	0	$ -	0.00000
1990	2.568	936	0	$ 1.632	0 57334
1991	2.763	365	0	$ 4.031	0 09059
1992	0	210	0	$ 3.821	0 05495
1993	0	7.490	0	$ -	0.00000
1994	0	7,987	0	$ -	0 00000
1995	1,902	1.267	0	$ 635	1.99413
1996	583	2,505	0	$ -	0.00000
1997	1.134	702	0	$ 432	1.62280
1998	3.116	126,675	0	$ -	0.00000
1999	4.917	8,320	0	$ -	0 00000
2000	4.242	11,097	0	$ -	0 00000
2001	2,768	6.176	0	$ -	0 00000
2002	27.460	0	0	$ 27.460	0 00000
2003	3,454	1,951	0	$ 28,963	0 06737
2004	1,632	641	0	$ 29.954	0 02141
2005	12,233	633	0	$ 41.555	0 01522
2006	48,299	3,136	0	$ 86,717	0.03617
2007	1,824	1,195	0	$ 87,347	0 01368
2008	18,103	1,577	0	$ 103.873	0.01518
2009	13.475	0	0	$ 117,348	0.00000
2010	5,070	713	0	$ 121,704	0 00586
2011	84,559	0	0	$ 206.263	0.00000
TOTAL	$ 251,254	$ 263,602	$ 171	$ 1,089,803	0.24188

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0 5	0.24188	0 75812	0.87906	2 62422
2011	1.5	0.24188	0.75812	0.66643	1 98947
2010	2.5	0.24188	0 75812	0.50524	1 50826
2009	3 5	0.24188	0 75812	0.38303	1 14344
2008	4 5	0.24188	0.75812	0.29038	0 86686
2007	5 5	0.24188	0.75812	0.22014	0 65719
2006	6.5	0.24188	0 75812	0 16690	0.49823
2005	7 5	0.24188	0.75812	0.12653	0.37771
2004	8 5	0 24188	0 75812	0.09592	0.28635
2003	9.5	0.24188	0.75812	0.07272	0.21709
2002	10 5	0.24188	0 75812	0.05513	0.16458
2001	11 5	0.24188	0 75812	0 04180	0 12477
2000	12 5	0.24188	0 75812	0.03169	0 09459
1999	13.5	0 24188	0.75812	0.02402	0 07171
1998	14.5	0 24188	0 75812	0.01821	0.05437
1997	15 5	0.24188	0.75812	0.01381	0 04122
1996	16.5	0.24188	0 75812	0.01047	0.03125
1995	17 5	0.24188	0.75812	0.00794	0.02369
1994	18.5	0.24188	0.75812	0.00602	0.01796
1993	19 5	0.24188	0 75812	0.00456	0 01361
1992	20 5	0.24188	0.75812	0.00346	0 01032
1991	21 5	0.24188	0 75812	0 00262	0.00783
1990	22.5	0.24188	0.75812	0.00199	0 00593
1989	23.5	0 24188	0 75812	0.00151	0 00450
1988	24 5	0 24188	0 75812	0.00114	0.00341
1987	25 5	0.24188	0.75812	0 00087	0.00258
1986	26.5	0.24188	0 75812	0.00066	0.00196
1985	27 5	0.24188	0.75812	0.00050	0 00149
1984	28 5	0.24188	0 75812	0.00038	0 00113
1983	29.5	0.24188	0 75812	0.00029	0.00085
1982	30 5	0 24188	0 75812	0 00022	0 00065
1981	31.5	0.24188	0.75812	0 00016	0 00049
1980	32.5	0.24188	0.75812	0.00012	0 00037
1979	33.5	0.24188	0 75812	0.00009	0.00028
1978	34 5	0 24188	0 75812	0.00007	0 00021
1977	35 5	0.24188	0 75812	0 00005	0 00016
1976	36 5	0.24188	0 75812	0 00004	0.00012
1975	37 5	0.24188	0 75812	0.00003	0 00009
1974	38 5	0 24188	0 75812	0.00002	0 00007
1973	39 5	0 24188	0 75812	0 00002	0 00005
1972	40.5	0 24188	0 75812	0 00001	0 00004
1971	41.5	0.24188	0 75812	0.00001	0.00003
1970	42 5	0.24188	0 75812	0.00001	0.00002
1969	43 5	0 24188	0 75812	0 00001	0 00002
1968	44.5	0 24188	0 75812	0 00000	0 00001
1967	45.5	0 24188	0 75812	0.00000	0.00001
1966	46.5	0 24188	0 75812	0.00000	0 00001
1965	47.5	0.24188	0 75812	0 00000	0 00001
1964	48.5	0.24188	0 75812	0 00000	0.00000
1963	49.5	0 24188	0 75812	0 00000	0.00000
1962	50.5	0.24188	0 75812	0.00000	0 00000
1961	51.5	0 24188	0 75812	0 00000	0.00000
1960	52 5	0 24188	0 75812	0 00000	0 00000
1959	53.5	0.24188	0 75812	0 00000	0.00000
1958	54.5	0.24188	0.75812	0.00000	0 00000
1957	55.5	0.24188	0.75812	0.00000	0 00000
1956	56 5	0.24188	0.75812	0 00000	0 00000
1955	57 5	0.24188	0 75812	0.00000	0 00000
1954	58.5	0 24188	0 75812	0.00000	0 00000

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Exhibit Kelly-2
Burns & McDonnell Letter – November 28, 2012

November 28, 2012

Ms. Billie Richert
VP Accounting & Interim CFO
Big Rivers Electric Corporation
201 Third Street
Henderson, KY 42420

Re: Updates Completed for Big Rivers Electric Corporation's Comprehensive Depreciation Study Dated November 2012

Dear Ms. Richert:

Burns & McDonnell respectfully submits this letter pertaining to updates completed in the preparation of the 2012 Comprehensive Depreciation Rate Study (2012 Study) compared to the prior Comprehensive Depreciation Rate Study (2010 Study) prepared for Big Rivers.

The Rural Utilities Service (RUS) previously approved the depreciation rates in the 2010 Study on February 28, 2011. The purpose of this letter is to provide the RUS with a list of items in the 2012 Study that have been updated since the 2010 Study.

Item 1: Plant Account Balances and Reserve Balances are Updated to July 31, 2012
Big Rivers' 2012 Study reflects production plant, transmission, and general plant account balances and reserve balances as of July 31, 2012. The 2010 Study included production plant, transmission, and general plant account balances and reserve balances as of April 30, 2010.

Item 2: Existing Depreciation Rates
The existing depreciation rates in the 2012 Study, contained in the tables on page ES-6 and III-6 (for comparison to the proposed depreciation rates) are the same depreciation rates that were proposed and approved in the 2010 Study.

Item 3 Remaining Service Lives
The remaining service lives in the 2012 Study reflect the passage of time between the two studies. The average service lives are the same in both studies for all accounts.

Item 4 Removal Costs
For the 2012 Study, Big Rivers provided salvage values and removal costs for 2010 and 2011. The removal costs incurred by Big Rivers total \$6.7 million in 2010 and \$1.8 million in 2011. For perspective, Big Rivers' removal costs for the entire period from 1965 to 2010 were only \$6.4 million.

Burns & McDonnell SINCE 1898

Including very large removal costs incurred by Big Rivers in 2010 and 2011 resulted in unrealistic net salvage factors. Therefore, the net salvage factors for each production, transmission, and general plant account were taken directly from the net salvage analysis performed in the 2010 Study.

The large removal costs incurred by Big Rivers in 2010 and 2011were actually incurred, and do not appear unreasonable given the refurbishment retirements incurred at Wilson. However, Big Rivers' management decided that due to the short period of time since the 2010 Study was completed and approved and the expedited timeframe required for this report it would be appropriate to use net salvage factors that are consistent with the 2010 Study. The analysis required to incorporate the 2010 and 2011 removal costs in Big Rivers proposed depreciation rates has been deferred and will be addressed in a future depreciation study.

Burns & McDonnell greatly appreciates the opportunity to provide this summary of updates completed in the preparation of the 2012 Comprehensive Depreciation Rate Study for Big Rivers. If you have any additional questions or would like to discuss this information please contact me at 816-822-4354 or Ted Kelly at 816-822-3208.

Sincerely,

Burns & McDonnell

Jon Summerville
Project Manager
Business & Technology Services

Ted J. Kelly
Principal and Project Director
Business & Technology Services

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

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

DIRECT TESTIMONY

OF

TRAVIS A. SIEWERT
SENIOR STAFF ACCOUNTANT

ON BEHALF OF

BIG RIVERS ELECTRIC CORPORATION

FILED: January 15, 2013

DIRECT TESTIMONY
OF
TRAVIS A. SIEWERT

Table of Contents

DIRECT TESTIMONY
OF
TRAVIS A. SIEWERT

I. INTRODUCTION

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

A. My name is Travis A. Siewert. I am employed by Big Rivers Electric Corporation ("Big Rivers"), 201 Third Street, Henderson, Kentucky 42420, as a Senior Staff Accountant.

Q. Please describe your job responsibilities.

A. I report to the Director of Finance, who in turn reports to the Vice President of Accounting and Interim Chief Financial Officer. My responsibilities include maintaining Big Rivers' financial model, performing economic analysis, and analyzing financials.

Q. Briefly describe your education and work experience.

A. I have been employed by Big Rivers in the finance and accounting area since 2003 and have been performing the financial modeling function since July of 2009. I earned a Master of Science in Accountancy degree from the University of Southern Indiana and a Bachelor of Science in Accounting degree from Kentucky Wesleyan College. I am a Certified Public Accountant ("CPA") and a Certified Management Accountant ("CMA"). A summary of my education and work experience is attached as Exhibit Siewert-1.

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

A. Yes. I provided rebuttal testimony and responses to data requests in Case No. 2012-00063.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is (i) to describe the Big Rivers financial model, which is a product of the Big Rivers budgeting process, (ii) to describe the results of the Big Rivers financial model, and (iii) to sponsor certain filing requirements from 807 KAR 5:001.

Q. Are you sponsoring any exhibits?

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

1. Exhibit Siewert-1 Qualifications of Travis A. Siewert;
2. Exhibit Siewert-2 Big Rivers Financial Model; and
3. Exhibit Siewert-3 Financial Results With and Without Rate Increase.

III. BIG RIVERS FINANCIAL MODEL

Q. Please provide a general description of the Big Rivers financial model.

A. The Big Rivers financial model is an in-house developed spreadsheet model which calculates revenues and generates financial statements and financial metrics based on data provided by the budget, the production cost model, the load forecast, and rate design from the cost of service study.

Q. How does the Big Rivers financial model fit into the budget development process?

A. Big Rivers' budgeted expenditures are entered into the financial model, along with production cost model output data and load data to generate a full set of financial statements.

Q. What are the inputs to the Big Rivers financial model?

A. Inputs to the Big Rivers financial model include member base rates, demand and energy forecasts for billing purposes, production cost model outputs, debt schedules, depreciation and amortization, capital expenditures, and all expense items captured by the budget (including fixed departmental expenses and departmental labor budgets).

Q. What are the outputs of the Big Rivers financial model?

A. Outputs of the Big Rivers financial model include total revenues, expenses, margins, Times Interest Earned Ratio ("TIER"), and information included in the statement of operations, balance sheet, and cash flow statement.

Q. How is the revenue forecast developed in the Big Rivers financial model?

A. The revenue forecast is developed by applying the appropriate rates to the projected consumption for each rate class. For the Rural and Large Industrial classes, the demand and energy rates are applied to the projected demand and energy volumes respectively. For Alcan Primary Products Corporation ("Alcan") and Century Aluminum of Kentucky General Partnership ("Century") (collectively, the "Smelters"), the Big Rivers financial model mirrors the terms of the contractual agreements relating to electric service provided to the Smelters (the "Smelter Agreements") to determine the total revenue.

Q. Does the Big Rivers financial model determine the appropriate charges for the Fuel Adjustment Clause ("FAC"), Environmental Surcharge ("ES"), and Non-FAC Purchase Power Adjustment ("Non-FAC PPA") for each of the rate classes?

A. Yes. The financial model assumes that these rate mechanisms recover the costs that are appropriate for inclusion in the mechanisms. The financial model does not simulate the regulatory lag associated with each – in other words, the financial model assumes perfect rate treatment for the costs that qualify for inclusion in the FAC, ES, and Non-FAC PPA. The effects of this assumption over time for budgeting and ratemaking purposes should be negligible given the over/under recovery mechanisms built into Big Rivers' riders.

Q. How does the Big Rivers financial model apply the reserve funds that Big Rivers has established as part of the transaction that the Commission approved in Case No. 2007-00045 (the "Unwind Transaction")?

A. The Big Rivers financial model tracks three different reserve funds; the Economic Reserve ("ER"), the Rural Economic Reserve ("RER"), and the Transition Reserve. The ER and RER are both rate mitigation funds and are modeled to mirror two tariff riders: the Member Rate Stability Mechanism and the Rural Economic Reserve Rider, respectively. As such, they are used to mitigate the rates of the Rural and Large Industrial classes, and amounts drawn from the funds are recorded as revenue. The Transition Reserve, on the other hand, was recognized as revenue when received as a part of the Unwind Transaction. Therefore, the Transition Reserve is merely a "Special Funds" account that can serve to mitigate Big Rivers' need for cash, but cannot help with a revenue deficiency. Since there is not a cash shortfall in the financial model, the Transition Reserve is modeled to remain intact and is not utilized upon the termination of the Century power contract.

Q. Does the Big Rivers financial model reflect the terms and conditions of the Smelter Agreements?

A. Yes. The financial model includes a calculation of Base Monthly Energy that is entirely comprised of Base Fixed Energy (*i.e.*, the model assumes that Base Variable Energy is zero). The model determines the base rate for the Smelters as specified in the Smelter Agreements, *i.e.*, the rate results from the application of the Large Industrial demand charge to the contract demand, plus the Large Industrial energy charge assuming a 98% load factor, plus a 25 cents/MWh adder.

Q. How does the Big Rivers financial model address the revenue items specified in Sections 4 and 5 of the Smelter Agreements?

A. In addition to the FAC, ES, and Non-FAC PPA, the Smelter Agreements include numerous possible revenue items. These are listed below (with references to the relevant section of the Smelter Agreements included in parentheses). Big Rivers calculates the appropriate amounts for the TIER Adjustment Charge in Section 4.7.1, the Rebate in Section 4.9, and the Surcharge in Section 4.11 (noted in bold in the list). For budgeting purposes, Big Rivers assumes that the remaining revenue items in the list are zero.

1. Supplemental Power (Section 4.3);
2. Backup Energy Charge (Section 4.4);
3. Transmission Charge (Section 4.5);
4. Excess Reactive Demand Charge (Section 4.6);
5. **TIER Adjustment Charge (Section 4.7.1);**
6. Amortization of Restructuring Amount (Section 16.5.1);

7. **Rebate (Section 4.9);**
8. Equity Development Credit (Section 4.10);
9. **Surcharge (Section 4.11);**
10. Surplus Sales (Section 4.13.1);
11. Undeliverable Energy Sales (Section 4.13.1);
12. Potline Reduction Sales (Section 4.13.1);
13. Curtailment of Purchased Power (Section 4.13.2);
14. Economic Sales (Section 4.13.3);
15. Other Credits (Section 4.14);
16. Taxes (Section 4.15); and
17. Other Amounts (Section 5.1).

Q. How does the Big Rivers financial model address the TIER Adjustment Charge and Rebate?

A. The financial model calculates TIER (as defined in the Smelter Agreements, which is referred to as "Contract TIER") absent any TIER Adjustment Charge. If the resulting TIER is less than the 1.24 Contract TIER then a TIER Adjustment Charge is applied to the Smelter rate up to the point where either a 1.24 Contract TIER is achieved, or the contractual maximum TIER Adjustment Charge (currently $2.95 per MWh) is reached. If the Contract TIER exceeds 1.24 and the TIER Adjustment Charge is zero, then the financial model applies a rebate to all customer classes, consistent with the Big Rivers' Rebate Adjustment tariff and Section 4.9 of the Smelter Agreements.

Q. How does the Big Rivers financial model address the Surcharge?

A. The Surcharge calculation in the financial model is based on Section 4.11 of the Smelter Agreements. The terms set forth a) a fixed monthly amount based on the year; plus b) a $0.60 charge per MWh; plus c) a $0.60 charge per MWh as adjusted for fuel costs; minus d) a fixed monthly amount for the first 96 Billing Months of the contract. The Surcharge amount collected is then used to calculate the Surcredit amount applied to the Rural and Large Industrial rates.

Q. **How does the Big Rivers financial model address revenue from off system sales?**

A. Off-system sales revenues in the Big Rivers financial model are derived by applying the off-system sales prices to the off-system sales volumes from the production cost model output.

Q. **Does the Big Rivers financial model include any other non-member revenues?**

A. Yes, the Big Rivers financial model includes transmission revenue, rental income, interest income, and patronage allocations. All of these non-member revenues serve to offset expenses and improve TIER, thereby reducing the revenue required from Big Rivers' members.

Q. **Does the Big Rivers financial model determine the appropriate expenses related to the FAC, ES, and Non-FAC PPA for each of the rate classes?**

A. Yes. The Big Rivers financial model determines the costs that qualify for inclusion in these rate mechanisms.

Q. **How are the outputs of the production cost model incorporated into the Big Rivers financial model?**

A. A worksheet in the Big Rivers financial model captures data from the production cost model output file, net of the City of Henderson's share of the Station Two generating station. This worksheet captures MWh sales volumes, fuel purchased, off system sales price, purchased power volumes and prices, variable environmental compliance costs, and allowances allocated and consumed.

Q. How are capital expenditures incorporated into the Big Rivers financial model?

A. A worksheet in the Big Rivers financial model captures the capital expenditures contained in the capital budget. Capital expenditures are then reflected in the cash flow statement and on the balance sheet. Capital expenditures for compliance with the Mercury and Air Toxics Standards ("MATS") rule are also tracked on a separate sheet for inclusion in the environmental compliance rate base once the assets are placed into service.

Q. How are the expenses that are split between Big Rivers and the City of Henderson addressed in the Big Rivers financial model?

A. All costs included in the Big Rivers financial model are net of the City of Henderson's share of Station Two. Variable costs (derived from the production cost model) are allocated based on energy usage. Non-variable costs (derived from the budget) are allocated based on Big Rivers' budgeted capacity take from Station Two, as described in the Direct Testimony of Mr. Robert W. Berry.

Q. How is existing debt addressed in the Big Rivers financial model?

A. Information related to existing debt issues (beginning balances, principal payments, interest payments, and amortization of upfront costs) is entered to the Big Rivers financial model from existing debt amortization schedules. Existing debt issues include the RUS Series A Note, the RUS Series B Note, the County of Ohio Pollution Control Bonds, the CoBank Term Loan, the CFC Term Loan, and the CFC Equity Loan.

Q. What are the assumptions regarding future debt issues?

A. There are two new debt issues planned in the 2013-2014 period: (i) a debt issue to refinance the $58.8 million pollution control bond and (ii) a debt issue for environmental compliance assets. The pollution control bond refinancing is assumed to occur in March of 2013 with debt issuance costs of $1.4 million, an interest rate of 6% and 18-year level debt service. The debt issuance costs are amortized over the 18-year life of the debt. The environmental compliance borrowing is assumed to occur under a short-term (3 year) revolver while Big Rivers seeks long-term financing with RUS. Borrowings for environmental compliance occur as funds are needed during construction and bear an interest rate of 3%. Debt issuance costs of $0.4 million are amortized over the 3-year life of the short-term borrowing.

IV. FINANCIAL MODEL RESULTS

Q. Does the Big Rivers financial model calculate Big Rivers' projected margins and TIER?

A. Yes. The model determines Big Rivers' projected margins and TIER for 2013, 2014, and the fully forecasted test period (September 2013 to August 2014). These can be calculated both with and without the proposed rate increase.

Q. What are Big Rivers' projected margins with and without the proposed rate increase?

A. Projected margins for the following periods with and without the proposed increase are tabulated below.

Table 1. Margins Forecast

Period	Margins Without Proposed Rate Increase (Millions of $)	Margins With Proposed Rate Increase (Millions of $)
2013	(21.3)	4.9
Fully Forecasted Test Period	(65.6)	9.4
2014	(63.9)	11.4

Q. What is Big Rivers' projected TIER with and without the proposed rate increase?

A. Projected TIER for these periods with and without the proposed increase is tabulated below.

Table 2. TIER Forecast

Period	TIER Without Proposed Rate Increase	TIER With Proposed Rate Increase
2013	0.54	1.11
Fully Forecasted Test Period	(0.40)	1.20
2014	(0.35)	1.24

Q. Is the proposed rate increase necessary to allow Big Rivers to achieve the necessary margins and corresponding TIER outlined in the Direct Testimony of Ms. Billie J. Richert?

A. Yes. A comparison of Big Rivers' financial results with and without the proposed rate increase is provided in Exhibit Siewert-3. As that exhibit and the data in Tables 1 and 2 above plainly show, Big Rivers' financial situation absent the proposed rate increase is dire. The proposed rate increase allows Big Rivers to meet the minimum Margins For Interest Ratio ("MFIR") requirement of 1.10 in 2013, and also permits Big Rivers to secure a TIER of 1.24 in 2014 and TIER of 1.20 in the fully forecasted test period.

V. FILING REQUIREMENTS

Q. Are you sponsoring any of the answers provided in Tabs 1-62 which address Big Rivers' compliance with the fully forecasted test period filing requirements under 807 KAR 5:001 and its various subsections?

A. Yes. I hereby incorporate and adopt those portions of Tabs 1-62 for which I am identified as the sponsoring witness.

Q. Are you sponsoring any of the pro forma adjustments included in the revenue requirement tabulation in Exhibit Wolfram-2?

A. Yes. I am sponsoring Schedule 1.01 for the removal of revenues and expenses included in the FAC, Schedule 1.02 for the removal of revenues and expenses included in the ES, and Schedule 1.03 for the removal of revenues and expenses included in the Non-FAC PPA. These are the adjustments allowed by standard Commission practice and reflect the removal of the amounts for these rate mechanisms as calculated in the Big Rivers financial model.

VI. CONCLUSION

Q. What are your conclusions and recommendations to the Commission in this proceeding?

A. The fully forecasted test period in this case relies on a financial model and corresponding budget projection that is reasonable, reliable, made in good faith, and based on assumptions that are justified. The fully forecasted test period in this rate filing relies on the same financial model, assumptions, and results that are used by Big Rivers' management in the ordinary course of business. The financial model demonstrates that for 2013 and beyond, Big Rivers requires the proposed rate increase in order to meet its financial obligations. The Commission should approve the proposed rates as filed by Big Rivers in this proceeding.

Q. Does this conclude your testimony?

A. Yes.

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES CASE NO. 2012-00535

VERIFICATION

I, Travis A. Siewert, verify, state, and affirm that I prepared or supervised the preparation of my testimony filed with this Verification, and that testimony is true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Travis A. Siewert

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Travis A. Siewert on this the 8th day of January, 2013.

Notary Public, Ky. State at Large
My Commission Expires 8-9-14

Professional Summary

Travis Siewert, CPA, CMA
Senior Staff Accountant
Big Rivers Electric Corporation
201 3rd Street
Henderson, Kentucky 42420
(270) 844-6131

Professional Experience

Big Rivers Electric Corporation 2003 to present

Senior Staff Accountant

Financial Forecasting and Economic Analysis

Cash Management and Fixed Assets

Education

Masters of Science in Accountancy

University of Southern Indiana, Evansville, Indiana, May 2003

Bachelors of Science in Accounting (Magna Cum Laude)

Kentucky Wesleyan College, Owensboro, Kentucky, May 2002

Certifications

Certified Public Accountant – CPA

Certified Management Accountant – CMA

Professional Organizations

Kentucky Society of Certified Public Accountants

Institute of Management Accountants

American Institute of Certified Public Accountants

Big Rivers Electric Corporation
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Big Rivers Financial Model

		2013 January	2013 February	2013 March	2013 April	2013 May	2013 June	2013 July	2013 August	2013 September	2013 October	2013 November	2013 December	2013 Total
1														
2	**I. Sales**													
3														
4	**Energy (TWH)**													
5	Rural	0.25	0.21	0.19	0.15	0.17	0.22	0.24	0.23	0.18	0.15	0.18	0.25	2.41
6	Large Industrial	0.08	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.94
7	Century	0.35	0.32	0.35	0.34	0.35	0.34	0.35	0.22	0.00	0.00	0.00	0.00	2.62
8	Alcan	0.28	0.25	0.28	0.27	0.28	0.27	0.27	0.27	0.26	0.27	0.26	0.27	3.20
9	Market	[redacted]												
10	Total Energy Sales	1.07	0.96	1.03	0.91	0.94	0.96	1.03	1.00	0.68	0.75	0.72	0.75	10.78
11														
12	**Demand (MW)**													
13	Rural	540.18	482.11	418.81	328.15	374.55	472.17	493.51	533.48	416.26	336.41	377.17	494.38	5,267.19
14	Large Industrial	139.27	139.90	139.11	139.40	138.43	138.53	143.19	143.54	136.42	138.47	138.43	138.60	1,673.29
15														
16	**II. Rates, Accrual Based ($ / MWH)**													
17														
18	**Rural**													
19	Load Factor (%)	62.01%	64.21%	60.23%	62.59%	59.28%	63.76%	66.25%	59.00%	59.69%	61.52%	66.01%	66.76%	62.67%
20	Demand ($/ KW-mo.)	9.50	9.50	9.50	9.50	9.50	9.50	9.50	12.14	16.95	16.95	16.95	16.95	12.10
21	Energy ($/ MWH)	29.74	29.74	29.74	29.74	29.74	29.74	29.74	29.83	30.00	30.00	30.00	30.00	29.83
22	Base Rate ($/ MWH)	50.33	51.75	50.94	50.82	51.28	50.43	49.01	57.49	69.44	67.03	65.66	64.12	56.20
23														
24	Non-Smelter Non-FAC PPA	(1.36)	(1.36)	(1.36)	(1.36)	(1.36)	(1.36)	(1.36)	(1.36)	(0.78)	(0.78)	(0.78)	(0.78)	(1.18)
25	FAC	3.79	3.93	3.92	3.96	3.96	4.11	4.63	4.21	4.70	4.48	4.61	4.67	4.25
26	Environmental Surcharge	3.17	3.25	3.29	3.07	3.21	3.19	3.03	3.67	4.35	4.13	3.72	3.42	3.43
27	Surcredit	(3.54)	(3.85)	(4.33)	(5.05)	(4.75)	(3.87)	(3.53)	(2.87)	(1.91)	(2.14)	(1.91)	(1.54)	(3.23)
28	Total	3.42	3.32	2.88	1.97	2.42	3.43	4.13	5.02	7.14	6.47	6.42	6.55	4.45
29	Economic Reserve	(7.64)	(7.54)	(7.09)	(6.19)	(6.63)	(7.64)	(7.34)	(8.23)	(10.35)	(9.68)	(9.63)	(9.76)	(8.15)
30	Rural Economic Reserve	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
31	TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
32	Effective Rate ($/ MWH)	44.76	46.18	45.37	45.25	45.71	44.86	44.44	52.93	65.45	63.04	61.67	60.13	51.32
33														

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		2013 January	2013 February	2013 March	2013 April	2013 May	2013 June	2013 July	2013 August	2013 September	2013 October	2013 November	2013 December	2013 Total
34	**Large Industrial**													
35	Load Factor (%)	75.77%	79.04%	77.68%	76.94%	76.72%	77.06%	77.88%	76.94%	78.20%	76.55%	77.18%	76.59%	77.20%
36	Demand ($/ KW-mo.)	10.50	10.50	10.50	10.50	10.50	10.50	10.50	11.18	12.41	12.41	12.41	12.41	11.19
37	Energy ($/ MWH)	24.51	24.51	24.51	24.51	24.51	24.51	24.51	26.45	30.00	30.00	30.00	30.00	26.49
38	Power Factor Penalty/ Demand Cr. (Lrg. Ind.)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
39	Base Rate ($/ MWH)	43.13	44.27	42.67	43.46	42.90	43.43	42.63	45.98	52.04	51.79	52.33	51.78	46.34
40														
41	Non-Smelter Non-FAC PPA	(1.36)	(1.36)	(1.36)	(1.36)	(1.36)	(1.36)	(1.36)	(1.36)	(0.78)	(0.78)	(0.78)	(0.78)	(1.17)
42	FAC	3.79	3.93	3.92	3.96	3.96	4.11	4.63	4.21	4.70	4.48	4.61	4.67	4.25
43	Environmental Surcharge	2.75	2.81	2.79	2.65	2.72	2.78	2.67	2.99	3.33	3.25	3.01	2.80	2.88
44	Surcredit	(3.54)	(3.85)	(4.33)	(5.05)	(4.75)	(3.87)	(3.53)	(2.87)	(1.91)	(2.14)	(1.91)	(1.54)	(3.27)
45	Total	3.00	2.89	2.38	1.56	1.93	3.02	3.77	4.33	6.12	5.59	5.71	5.94	3.86
46	Economic Reserve	(7.21)	(7.10)	(6.59)	(5.77)	(6.15)	(7.23)	(6.98)	(7.55)	(9.33)	(8.80)	(8.92)	(9.15)	(7.56)
47	TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
48	Effective Rate ($/ MWH)	37.56	38.71	37.10	37.89	37.33	37.86	38.06	41.41	48.05	47.80	48.34	47.78	41.47
49														
50	**Non-Smelter Member Blend**													
51	Base Rate ($/ MWH)	48.60	49.78	48.46	48.29	48.57	48.60	47.39	54.50	64.21	61.87	61.66	61.12	53.43
52														
53	Non-Smelter Non-FAC PPA	(1.36)	(1.36)	(1.36)	(1.36)	(1.36)	(1.36)	(1.36)	(1.36)	(0.78)	(0.78)	(0.78)	(0.78)	(1.17)
54	FAC	3.79	3.93	3.92	3.96	3.96	4.11	4.63	4.21	4.70	4.48	4.61	4.67	4.25
55	Environmental Surcharge	3.07	3.14	3.14	2.93	3.05	3.08	2.94	3.50	4.04	3.83	3.51	3.27	3.28
56	Surcredit	(3.54)	(3.85)	(4.33)	(5.05)	(4.75)	(3.87)	(3.53)	(2.87)	(1.91)	(2.14)	(1.91)	(1.54)	(3.24)
57	Total	3.32	3.21	2.73	1.83	2.26	3.32	4.04	4.84	6.83	6.17	6.21	6.40	4.29
58	Economic Reserve	(7.53)	(7.42)	(6.94)	(6.04)	(6.48)	(7.53)	(7.25)	(8.05)	(10.05)	(9.38)	(9.42)	(9.61)	(7.99)
59	Rural Economic Reserve	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
60	TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61	Effective Rate ($/ MWH)	43.03	44.22	42.89	42.72	43.00	43.03	42.82	49.94	60.22	57.88	57.67	57.13	48.55
62														

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		2013 January	2013 February	2013 March	2013 April	2013 May	2013 June	2013 July	2013 August	2013 September	2013 October	2013 November	2013 December	2013 Total
63	**Smelters**													
64	Base Rate	39.43	39.43	39.43	39.43	39.43	39.43	39.43	40.72	47.60	47.60	47.60	47.60	41.02
65	TIER Adjustment	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.95
66	Total	42.38	42.38	42.38	42.38	42.38	42.38	42.38	43.67	50.55	50.55	50.55	50.55	43.97
67	Non-FAC PPA	(0.59)	(0.56)	(0.57)	(0.55)	(0.57)	(0.58)	(0.59)	(0.54)	(0.35)	(0.34)	(0.35)	(0.42)	(0.53)
68	FAC	3.79	3.93	3.92	3.96	3.96	4.11	4.63	4.21	4.70	4.48	4.61	4.67	4.16
69	Environmental Surcharge	2.48	2.48	2.55	2.38	2.48	2.50	2.44	2.72	3.03	2.97	2.73	2.56	2.56
70	Surcharge	1.85	1.92	1.85	1.87	1.85	1.87	1.86	1.87	1.88	1.86	1.88	1.86	1.87
71	TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
72	Effective Rate ($/ MWH)	49.92	50.16	50.13	50.04	50.11	50.29	50.73	51.94	59.81	59.52	59.41	59.22	52.03
73														
74	Market	[redacted]												

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		2013 January	2013 February	2013 March	2013 April	2013 May	2013 June	2013 July	2013 August	2013 September	2013 October	2013 November	2013 December	2013 Total
75														
76	**III. Statement of Operations (Millions of $)**													
77														
78	Electric Energy Revenues	[redacted]												
79	Income From Leased Property Net													
80	Other Operating Revenue and Income	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	3.70
81	**TOTAL OPER. REVENUES & PAT. CAPITAL**	[redacted]												
82														
83	Operating Expense-Production-Excluding Fuel	[redacted]												
84	Operating Expense-Production-Fuel													
85	Operating Expense-Other Power Supply													
86	Operating Expense-Transmission													
87	Operating Expense-RTO/ISO													
88	Operating Expense-Distribution													
89	Operating Expense-Customer Accounts													
90	Operating Expense-Customer Service and Information													
91	Operating Expense-Sales													
92	Operating Expense-Administrative and General													
93	**TOTAL OPERATION EXPENSE**													
94														
95	Maintenance Expense-Production	[redacted]												
96	Maintenance Expense-Transmission													
97	Maintenance Expense-Distribution													
98	Maintenance Expense-General Plant													
99	**TOTAL MAINTENANCE EXPENSE**													
100														

Big Rivers Electric Corporation
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		2013 January	2013 February	2013 March	2013 April	2013 May	2013 June	2013 July	2013 August	2013 September	2013 October	2013 November	2013 December	2013 Total
101	Depreciation and Amortization Expense	3.44	3.44	3.45	3.45	3.47	3.48	3.49	3.49	3.64	3.65	3.66	3.66	42.31
102	Taxes	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
103	Interest on Long-Term Debt	3.80	3.49	3.93	3.84	3.94	3.80	3.94	3.94	3.82	3.97	3.87	3.97	46.31
104	Interest Charged to Construction - Credit	(0.00)	(0.01)	(0.02)	(0.05)	(0.04)	(0.06)	(0.08)	(0.04)	(0.06)	(0.10)	(0.14)	(0.18)	(0.77)
105	Other Interest Expense	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
106	Asset Retirement Obligation													
107	Other Deductions	0.05	0.04	0.05	0.05	0.04	0.06	0.04	0.04	0.04	0.05	0.05	0.07	0.58
108														
109	**TOTAL COST OF ELECTRIC SERVICE**	[redacted]												
110														
111	**OPERATING MARGINS**	3.74	1.61	(0.95)	(3.59)	(6.03)	0.70	2.58	2.57	(0.31)	(2.67)	0.22	3.80	1.66
112														
113	Interest Income	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.16	2.02
114	Allowance For Funds Used During Construction													
115	Income (Loss) From Equity Investments													
116	Other Non-Operating Income (Net)													
117	Generation and Transmission Capital Credits													
118	Other Capital Credits and Patronage Dividends	0.00	0.00	1.24	0.03	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	1.27
119	Extraordinary Items													
120	**NET PATRONAGE CAPITAL OR MARGIN**	3.91	1.78	0.46	(3.40)	(5.86)	0.87	2.75	2.74	(0.15)	(2.50)	0.38	3.96	4.95
121														
122														

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		2013 January	2013 February	2013 March	2013 April	2013 May	2013 June	2013 July	2013 August	2013 September	2013 October	2013 November	2013 December	2013 Total
123	**IV. Balance Sheet (Millions of $)**													
124	Total Utility Plant in Service	2,013.27	2,014.57	2,018.96	2,025.29	2,031.25	2,034.08	2,036.69	2,038.22	2,040.49	2,046.15	2,048.32	2,048.69	2,048.69
125	Construction Work in Progress	40.00	40.00	40.00	40.00	40.90	42.11	44.43	46.75	50.29	57.51	64.76	72.20	72.20
126	Total Utility Plant	2,053.27	2,054.57	2,058.96	2,065.29	2,072.15	2,076.19	2,081.12	2,084.97	2,090.79	2,103.66	2,113.09	2,120.89	2,120.89
127	Accum. Provision for Depreciation and Amort.	970.49	973.80	976.14	977.89	979.77	982.65	985.61	988.91	992.12	994.27	997.53	1,001.36	1,001.36
128	**NET UTILITY PLANT**	1,082.78	1,080.77	1,082.82	1,087.40	1,092.39	1,093.54	1,095.50	1,096.06	1,098.67	1,109.40	1,115.56	1,119.53	1,119.53
129														
130	Non-Utility Property (Net)													
131	Invest. In Assoc. Org - Patronage Capital	3.68	3.68	4.14	4.15	4.15	4.15	4.15	4.15	4.15	4.15	4.15	4.15	4.15
132	Invest. In Assoc. - Other - General Funds	43.84	43.52	43.52	43.52	43.21	43.21	43.21	42.88	42.88	42.88	42.55	42.55	42.55
133	Other Investments	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
134	Special Funds	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05
135	Special Funds (Transition Reserve)	35.03	35.04	35.05	35.05	35.06	35.07	35.08	35.09	35.10	35.11	35.12	35.13	35.13
136	Special Funds (Economic Reserve)	78.16	76.11	74.29	72.98	71.44	69.27	66.95	64.44	61.91	59.76	57.39	54.30	54.30
137	Special Funds (Rural Economic Reserve)	64.50	64.59	64.69	64.79	64.89	64.99	65.09	65.19	65.29	65.39	65.49	65.60	65.60
138	**TOTAL OTHER PROP. AND INVESTMENTS**	226.27	224.01	222.77	221.56	219.82	217.76	215.54	212.83	210.40	208.37	205.77	202.79	202.79
139														
140	Cash - General Funds	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
141	Cash - Construction Funds - Trustee													
142	Special Deposits	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60
143	Temporary Investments	107.68	110.08	114.27	113.78	102.03	101.93	100.20	94.01	114.21	105.98	95.16	82.84	82.84
144	Accounts Receivable - Sales of Energy (Net)	51.46	46.36	48.73	43.81	45.47	47.34	51.19	50.01	38.17	38.53	38.41	42.26	42.26
145	Accounts Receivable - Other (Net)	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22
146	Fuel Stock	32.22	32.33	32.41	32.27	32.22	32.34	32.45	32.47	32.76	32.97	33.10	33.18	33.18
147	Materials and Supplies - Other	26.24	26.30	26.35	26.41	26.46	26.52	26.58	26.64	26.70	26.76	26.83	26.89	26.89
148	Prepayments	3.60	3.29	2.97	2.66	2.35	2.05	1.76	1.46	1.17	0.87	0.58	4.18	4.18
149	Other Current and Accrued Assets	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71
150	**TOTAL CURRENT AND ACCRUED ASSETS**	223.73	220.89	227.28	221.46	211.08	212.73	214.71	207.13	215.54	207.65	196.61	191.89	191.89
151														
152	Unamortized Debt Discount & Extraor. Prop. Losses	3.78	5.16	5.13	5.09	5.06	5.03	5.00	4.96	4.93	4.90	4.86	4.83	4.83
153	Regulatory Assets	1.24	1.40	1.50	1.63	1.80	2.08	2.13	6.72	6.58	6.44	6.29	6.15	6.15
154	Other Deferred Debits	2.89	2.87	2.81	2.76	2.75	2.69	2.64	2.62	2.56	2.51	2.47	2.42	2.42
155	Accumulated Deferred Income Taxes	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
156														
157	**TOTAL ASSETS AND OTHER DEBITS**	1,540.70	1,535.11	1,542.30	1,539.92	1,532.89	1,533.83	1,535.53	1,530.32	1,538.68	1,539.25	1,531.57	1,527.62	1,527.62
158														

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		2013 January	2013 February	2013 March	2013 April	2013 May	2013 June	2013 July	2013 August	2013 September	2013 October	2013 November	2013 December	2013 Total
159														
160	**TOTAL MARGINS & EQUITY**	401.19	402.97	403.43	400.03	394.17	395.04	397.78	400.53	400.38	397.88	398.26	402.23	402.23
161														
162	Long-Term Debt - RUS	210.37	210.37	212.23	212.24	212.24	214.16	214.17	214.17	216.13	216.14	216.14	218.13	218.13
163	Long-Term Debt - Other	714.88	711.06	714.25	714.25	710.39	718.08	718.08	715.08	730.02	730.02	726.99	725.10	725.10
164	**TOTAL LONG-TERM DEBT**	925.25	921.43	926.48	926.49	922.63	932.24	932.25	929.25	946.14	946.16	943.13	943.23	943.23
165														
166	Notes Payable	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
167	Accounts Payable	28.37	26.95	30.61	29.95	33.79	28.31	29.07	28.41	22.93	24.95	22.37	20.18	20.18
168	Accounts Payable (TIER Rebate)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
169	Taxes Accrued	0.55	0.88	1.20	1.53	1.85	2.18	2.50	0.69	1.01	1.34	1.10	0.81	0.81
170	Interest Accrued	5.01	4.68	4.24	6.92	7.00	4.86	5.13	5.25	4.50	7.29	7.40	4.89	4.89
171	Other Current and Accrued Liabilities	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29
172														
173	**TOTAL CURRENT AND ACCRUED LIAB.**	42.23	40.80	44.34	46.69	50.93	43.64	44.99	42.64	36.73	41.87	39.16	34.17	34.17
174														
175	Deferred Credits	3.91	3.68	3.47	3.29	3.10	2.87	2.62	2.36	2.25	2.15	2.04	1.92	1.92
176	Deferred Credits (Economic Reserve)	78.16	76.11	74.29	72.98	71.44	69.27	66.95	64.44	61.91	59.76	57.39	54.30	54.30
177	Deferred Credits (Rural Economic Reserve)	64.50	64.59	64.69	64.79	64.89	64.99	65.09	65.19	65.29	65.39	65.49	65.60	65.60
178	Accumulated Operating Provisions	25.46	25.53	25.59	25.65	25.72	25.78	25.85	25.91	25.98	26.04	26.11	26.17	26.17
179	Obligation under Capital Leases - Noncurrent													
180														
181	**TOTAL LIABILITIES AND OTHER CREDITS**	1,540.70	1,535.11	1,542.30	1,539.92	1,532.89	1,533.83	1,535.53	1,530.32	1,538.68	1,539.25	1,531.57	1,527.62	1,527.62
182														

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183														
184	**V. Cash Flow Statement (Millions of $)**													
185	Operating Receipts													
186	Rural	11.15	9.61	8.51	6.69	7.55	9.72	10.81	12.39	11.71	9.71	11.06	14.77	123.68
187	Large Industrial	2.95	2.88	2.98	2.93	2.95	2.91	3.16	3.40	3.69	3.77	3.72	3.77	39.11
188	Smelters	31.30	28.41	31.43	30.37	31.42	30.51	31.44	25.13	15.53	15.97	15.43	15.89	302.82
189	Offsystem	[redacted]												
190	Lease Income													
191	Other Operating Revenues	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	3.70
192	Gain on Sale of Allowances	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
193	Other	0.00	0.00	1.24	0.03	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	1.27
194	Interest Earnings	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.16	2.02
195	Total Receipts	[redacted]												
196														
197	Operating Disbursements													
198	PPA	[redacted]												
199	Fuel Costs													
200	Fuel Costs (Labor & Exp)													
201	Domtar	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
202	Power Supply (P Power, APM, Cogen, & TVA Tran)	[redacted]												
203	Production O&M													
204	Transmission O&M													
205	A&G													
206	Working Capital	(0.24)	(4.62)	(1.45)	(4.88)	(3.13)	6.72	2.46	0.67	(6.98)	(2.29)	2.08	9.93	(1.72)
207	Other	0.11	0.16	0.11	0.14	0.17	0.31	0.06	4.59	(0.14)	(0.14)	(0.14)	(0.14)	5.09
208	Total Disbursements	[redacted]												
209														
210	Operating Receipts less Disbursements	8.70	11.06	7.38	7.55	3.08	(1.11)	5.21	2.39	11.78	5.31	3.53	(1.30)	63.57

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		2013 January	2013 February	2013 March	2013 April	2013 May	2013 June	2013 July	2013 August	2013 September	2013 October	2013 November	2013 December	2013 Total
211														
212	Capital Expenditures													
213	Generation	[redacted]												
214	Transmission	0.55	0.85	0.58	0.81	0.63	0.80	0.52	0.49	0.41	0.85	1.58	0.15	8.22
215	A&G	0.02	0.60	0.30	0.58	0.10	0.10	0.10	0.10	0.15	0.20	0.20	0.20	2.64
216	Other / IT	0.05	0.10	0.24	0.48	0.47	0.39	0.31	0.22	0.15	0.11	0.12	0.08	2.68
217	Total Capital Expenditures	[redacted]												
218														
219	Income Taxes from Operations	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
220														
221	Net Pre-Finance Cash Flow	7.48	9.35	1.63	(0.72)	(5.61)	(5.97)	(0.44)	(1.90)	5.31	(9.24)	(6.43)	(9.04)	(15.57)
222														
223	Financing													
224	Principal	0.00	3.83	(3.19)	0.00	3.86	(7.69)	0.00	3.00	(14.94)	0.00	3.03	1.88	(10.22)
225	Interest	3.68	3.81	2.49	1.13	3.85	4.03	3.65	3.82	2.62	1.17	3.76	4.49	38.47
226	Debt Issuance Cost	0.00	1.40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	1.42
227	Line of Credit (Upfront Fee)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
228	Aggregate Debt Service (incl. Line of Credit)	3.68	9.04	(0.70)	1.13	7.71	(3.67)	3.65	6.82	(12.32)	1.17	6.79	6.39	29.67
229														
230	Post-Finance Cash Flow	3.80	0.32	2.34	(1.84)	(13.32)	(2.30)	(4.09)	(8.72)	17.63	(10.41)	(13.22)	(15.43)	(45.25)
231														
232	Unwind Transaction													
233	Cash Proceeds													
234	Debt Reduction													
235	Misc. Transaction													
236	Net Before Member Reserves													
237	Station Two O&M Fund													
238	Rural Economic Reserve	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
239	Economic Reserve	2.47	2.10	1.86	1.36	1.58	2.21	2.37	2.55	2.57	2.19	2.41	3.12	26.78
240	Net Before Transition Reserve	2.47	2.10	1.86	1.36	1.58	2.21	2.37	2.55	2.57	2.19	2.41	3.12	26.78
241														

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		2013 January	2013 February	2013 March	2013 April	2013 May	2013 June	2013 July	2013 August	2013 September	2013 October	2013 November	2013 December	2013 Total
242	Ending Cash Balances (Incl. Transition Reserve)	142.71	145.13	149.32	148.84	137.10	137.01	135.29	129.11	149.31	141.09	130.28	117.97	117.97
243	Ending Cash Balances excl. Transition Reserve)	107.68	110.09	114.28	113.79	102.04	101.94	100.20	94.02	114.21	105.98	95.17	82.85	82.85
244	Change in Working Capital													
245	Other Property	0.00	(0.32)	0.46	0.01	(0.32)	0.00	0.00	(0.32)	0.00	0.00	(0.33)	0.00	(0.81)
246	Accounts Receivable	1.74	(5.10)	2.38	(4.93)	1.67	1.87	3.84	(1.18)	(11.84)	0.36	(0.12)	3.85	(7.46)
247	Materials, Supplies & Other	0.06	0.06	0.06	0.06	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.71
248	Prepayments	(0.59)	(0.30)	(0.30)	(0.30)	(0.30)	(0.30)	(0.30)	(0.30)	(0.30)	(0.30)	(0.30)	3.61	0.06
249	Other Current Assets	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
250	Accounts Payable	(1.05)	1.42	(3.66)	0.66	(3.84)	5.48	(0.75)	0.66	5.48	(2.02)	2.58	2.19	7.14
251	Taxes Accrued	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	1.81	(0.32)	(0.32)	0.24	0.29	(0.58)
252	Other Accruals	(0.06)	(0.06)	(0.06)	(0.06)	(0.06)	(0.06)	(0.06)	(0.06)	(0.06)	(0.06)	(0.07)	(0.07)	(0.77)
253	Total	(0.24)	(4.62)	(1.45)	(4.88)	(3.13)	6.72	2.46	0.67	(6.98)	(2.29)	2.08	9.93	(1.72)
254														

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		2013 January	2013 February	2013 March	2013 April	2013 May	2013 June	2013 July	2013 August	2013 September	2013 October	2013 November	2013 December	2013 Total
255														
256	**VI. Cash Flow Statement - Indirect (Millions of $)**													
257														
258	**Cash Flows From Operating Activities:**													
259	Net Margin	3.91	1.78	0.46	(3.40)	(5.86)	0.87	2.75	2.74	(0.15)	(2.50)	0.38	3.96	4.95
260	Adjustments to reconcile net margin to net cash													
261	provided by operating activities:													
262	Depreciation and amortization	3.71	3.72	3.72	3.73	3.75	3.76	3.77	3.78	3.92	3.93	3.94	3.94	45.66
263	Interest compounded - RUS Series A Note	0.01	0.00	0.00	0.01	0.00	0.00	0.01	0.00	0.00	0.01	0.00	0.00	0.04
264	Interest compounded - RUS Series B Note	0.00	0.00	1.86	0.00	0.00	1.91	0.00	0.00	1.96	0.00	0.00	1.99	7.72
265	Noncash member rate mitigation revenue	(2.82)	(2.48)	(2.17)	(1.67)	(1.94)	(2.72)	(2.67)	(7.39)	(2.54)	(2.15)	(2.38)	(3.09)	(34.03)
266	Changes in certain assets and liabilities:													
267	Other property	0.00	0.32	(0.46)	(0.01)	0.32	0.00	0.00	0.32	0.00	0.00	0.33	0.00	0.81
268	Accounts receivable	(1.74)	5.10	(2.38)	4.93	(1.67)	(1.87)	(3.84)	1.18	11.84	(0.36)	0.12	(3.85)	7.46
269	Inventories	(0.28)	(0.17)	(0.13)	0.08	(0.01)	(0.18)	(0.17)	(0.08)	(0.35)	(0.27)	(0.20)	(0.14)	(1.89)
270	Prepayments	0.61	0.31	0.31	0.31	0.31	0.30	0.30	0.30	0.30	0.30	0.30	(3.61)	0.03
271	Other current assets	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
272	Accounts payable	1.05	(1.42)	3.66	(0.66)	3.84	(5.48)	0.75	(0.66)	(5.48)	2.02	(2.58)	(2.19)	(7.14)
273	Taxes accrued	0.32	0.32	0.32	0.32	0.32	0.32	0.32	(1.81)	0.32	0.32	(0.24)	(0.29)	0.58
274	Other accruals	0.23	(0.23)	(0.30)	2.78	0.15	(2.05)	0.34	0.20	(0.66)	2.84	0.11	(2.52)	0.90
275	Net cash provided by operating activities	5.02	7.25	4.89	6.42	(0.77)	(5.14)	1.56	(1.43)	9.16	4.15	(0.23)	(5.79)	25.09
276														
277	**Cash Flows From Investing Activities:**													
278	Capital expenditures	(1.22)	(1.70)	(5.75)	(8.27)	(8.69)	(4.86)	(5.65)	(4.29)	(6.47)	(14.55)	(9.96)	(7.73)	(79.14)
279	Net proceeds from restricted investments	2.46	2.09	1.85	1.35	1.57	2.20	2.36	2.54	2.56	2.18	2.40	3.11	26.67
280	Net cash provided by (used in) inv. Activities	1.24	0.38	(3.90)	(6.92)	(7.12)	(2.65)	(3.29)	(1.75)	(3.91)	(12.37)	(7.56)	(4.62)	(52.47)

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281														
282	**Cash Flows From Financing Activities:**													
283	Net principal payments on debt obligations	0.00	(3.83)	3.19	0.00	(3.86)	7.69	0.00	(3.00)	14.94	0.00	(3.03)	(1.88)	10.22
284	Debt issuance cost	0.00	(1.40)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.02)	(1.42)
285	Line of Credit (Upfront Fee)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
286	Net cash provided by (used in) Financihng Activities	0.00	(5.23)	3.19	0.00	(3.86)	7.69	0.00	(3.00)	14.94	0.00	(3.03)	(1.90)	8.80
287														
288	Net increase (decrease) in cash	6.26	2.40	4.19	(0.49)	(11.75)	(0.10)	(1.74)	(6.19)	20.19	(8.23)	(10.82)	(12.32)	(18.57)
289														
290	**Cash and Cash Equivalents - Beg. of Period**													101.42
291	**Cash and Cash Equivalents - End of Period**													82.85

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		2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	2014 September	2014 October	2014 November	2014 December	2014 Total
1														
2	**I. Sales**													
3														
4	**Energy (TWH)**													
5	Rural	0.25	0.21	0.19	0.15	0.17	0.22	0.25	0.24	0.18	0.16	0.18	0.25	2.45
6	Large Industrial	0.08	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.94
7	Century	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	Alcan	0.27	0.24	0.27	0.26	0.27	0.26	0.27	0.27	0.26	0.27	0.26	0.27	3.16
9	Market	[redacted]												
10	Total Energy Sales	0.77	0.69	0.66	0.60	0.63	0.68	0.71	0.71	0.68	0.74	0.72	0.74	8.32
11														
12	**Demand (MW)**													
13	Rural	548.56	489.60	425.32	333.27	380.07	479.13	500.79	541.33	422.41	341.34	383.06	502.06	5,346.95
14	Large Industrial	140.57	139.90	139.11	139.40	138.43	138.53	143.19	143.54	136.42	138.47	138.43	138.60	1,674.59
15														
16	**II. Rates, Accrual Based ($ / MWH)**													
17														
18	**Rural**													
19	Load Factor (%)	62.04%	64.25%	60.26%	62.62%	59.36%	63.85%	66.35%	59.09%	59.77%	61.61%	66.05%	66.80%	62.74%
20	Demand ($/ KW-mo.)	16.95	16.95	16.95	16.95	16.95	16.95	16.95	16.95	16.95	16.95	16.95	16.95	16.95
21	Energy ($/ MWH)	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00
22	Base Rate ($/ MWH)	66.72	69.26	67.81	67.59	68.38	66.87	64.34	68.56	69.38	66.98	65.64	64.11	67.01
23														
24	Non-Smelter Non-FAC PPA	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.33)	(0.33)	(0.33)	(0.33)	(0.64)
25	FAC	4.90	5.07	5.22	5.34	5.44	5.64	5.66	5.70	5.77	5.38	5.43	5.44	5.41
26	Environmental Surcharge	3.73	3.88	3.67	3.99	3.94	3.87	3.70	4.55	5.35	5.10	4.65	4.22	4.18
27	Surcredit	(1.50)	(1.64)	(1.84)	(2.15)	(2.02)	(1.64)	(1.51)	(1.56)	(1.89)	(2.12)	(1.89)	(1.52)	(1.73)
28	Total	7.13	7.32	7.05	7.18	7.37	7.87	7.85	8.69	9.23	8.37	8.19	8.14	7.87
29	Economic Reserve	(10.34)	(10.53)	(10.26)	(10.39)	(10.58)	(11.08)	(9.06)	(9.90)	(10.44)	(9.58)	(9.40)	(9.35)	(10.05)
30	Rural Economic Reserve	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
31	TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
32	Effective Rate ($/ MWH)	62.73	65.27	63.81	63.60	64.38	62.88	62.35	66.56	67.84	65.44	64.10	62.57	64.18
33														

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34	**Large Industrial**													
35	Load Factor (%)	75.71%	79.04%	77.68%	76.94%	76.72%	77.06%	77.88%	76.94%	78.20%	76.55%	77.18%	76.59%	77.20%
36	Demand ($/ KW-mo.)	12.41	12.41	12.41	12.41	12.41	12.41	12.41	12.41	12.41	12.41	12.41	12.41	12.41
37	Energy ($/ MWH)	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00
38	Power Factor Penalty/ Demand Cr. (Lrg. Ind.)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
39	Base Rate ($/ MWH)	52.03	53.37	51.47	52.40	51.74	52.37	51.42	51.68	52.04	51.79	52.33	51.78	52.02
40														
41	Non-Smelter Non-FAC PPA	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.33)	(0.33)	(0.33)	(0.33)	(0.63)
42	FAC	4.90	5.07	5.22	5.34	5.44	5.64	5.66	5.70	5.77	5.38	5.43	5.44	5.42
43	Environmental Surcharge	2.96	3.05	2.85	3.16	3.06	3.10	3.02	3.52	4.11	4.03	3.77	3.47	3.34
44	Surcredit	(1.50)	(1.64)	(1.84)	(2.15)	(2.02)	(1.64)	(1.51)	(1.56)	(1.89)	(2.12)	(1.89)	(1.52)	(1.77)
45	Total	6.37	6.49	6.23	6.35	6.48	7.09	7.17	7.66	7.99	7.29	7.32	7.39	6.99
46	Economic Reserve	(9.58)	(9.70)	(9.44)	(9.56)	(9.69)	(10.31)	(8.38)	(8.87)	(9.20)	(8.50)	(8.53)	(8.60)	(9.19)
47	TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
48	Effective Rate ($/ MWH)	48.04	49.37	47.48	48.41	47.75	48.37	49.43	49.69	50.50	50.25	50.79	50.24	49.19
49														
50	**Non-Smelter Member Blend**													
51	Base Rate ($/ MWH)	63.22	65.13	62.96	62.44	63.05	63.12	61.09	64.23	64.23	61.89	61.69	61.14	62.84
52														
53	Non-Smelter Non-FAC PPA	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.33)	(0.33)	(0.33)	(0.33)	(0.64)
54	FAC	4.90	5.07	5.22	5.34	5.44	5.64	5.66	5.70	5.77	5.38	5.43	5.44	5.42
55	Environmental Surcharge	3.54	3.66	3.43	3.71	3.66	3.67	3.53	4.29	4.99	4.74	4.39	4.04	3.95
56	Surcredit	(1.50)	(1.64)	(1.84)	(2.15)	(2.02)	(1.64)	(1.51)	(1.56)	(1.89)	(2.12)	(1.89)	(1.52)	(1.74)
57	Total	6.95	7.10	6.81	6.90	7.08	7.67	7.68	8.43	8.86	8.01	7.93	7.96	7.62
58	Economic Reserve	(10.16)	(10.31)	(10.02)	(10.11)	(10.29)	(10.88)	(8.89)	(9.64)	(10.08)	(9.22)	(9.14)	(9.17)	(9.81)
59	Rural Economic Reserve	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
60	TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61	Effective Rate ($/ MWH)	59.23	61.13	58.97	58.44	59.06	59.12	59.10	62.23	62.69	60.35	60.15	59.60	60.01
62														

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63	**Smelters**													
64	Base Rate	47.60	47.60	47.60	47.60	47.60	47.60	47.60	47.60	47.60	47.60	47.60	47.60	47.60
65	TIER Adjustment	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94
66	Total	50.54	50.54	50.54	50.54	50.54	50.54	50.54	50.54	50.54	50.54	50.54	50.54	50.54
67	Non-FAC PPA	(0.41)	(0.35)	(0.36)	(0.31)	(0.34)	(0.38)	(0.41)	(0.40)	(0.34)	(0.32)	(0.34)	(0.41)	(0.36)
68	FAC	4.90	5.07	5.22	5.34	5.44	5.64	5.66	5.70	5.77	5.38	5.43	5.44	5.42
69	Environmental Surcharge	2.70	2.72	2.62	2.86	2.80	2.81	2.78	3.23	3.78	3.71	3.44	3.19	3.06
70	Surcharge	1.86	1.93	1.86	1.88	1.86	1.88	1.86	1.86	1.88	1.86	1.88	1.86	1.87
71	TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
72	Effective Rate ($/ MWH)	59.59	59.91	59.88	60.32	60.31	60.49	60.43	60.92	61.62	61.17	60.95	60.62	60.52
73														
74	Market	[redacted]												

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		2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	2014 September	2014 October	2014 November	2014 December	2014 Total
75														
76	III. Statement of Operations (Millions of $)													
77														
78	Electric Energy Revenues	[redacted]												
79	Income From Leased Property Net													
80	Other Operating Revenue and Income	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	3.70
81	TOTAL OPER. REVENUES & PAT. CAPITAL	[redacted]												
82														
83	Operating Expense-Production-Excluding Fuel	[redacted]												
84	Operating Expense-Production-Fuel													
85	Operating Expense-Other Power Supply													
86	Operating Expense-Transmission													
87	Operating Expense-RTO/ISO													
88	Operating Expense-Distribution													
89	Operating Expense-Customer Accounts													
90	Operating Expense-Customer Service and Information													
91	Operating Expense-Sales													
92	Operating Expense-Administrative and General													
93	TOTAL OPERATION EXPENSE													
94														
95	Maintenance Expense-Production	[redacted]												
96	Maintenance Expense-Transmission													
97	Maintenance Expense-Distribution													
98	Maintenance Expense-General Plant													
99	TOTAL MAINTENANCE EXPENSE													
100														

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		2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	2014 September	2014 October	2014 November	2014 December	2014 Total
101	Depreciation and Amortization Expense	3.66	3.67	3.67	3.68	3.69	3.71	3.71	3.71	3.84	3.85	3.86	3.86	44.91
102	Taxes	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
103	Interest on Long-Term Debt	3.91	3.66	3.98	3.90	4.01	3.88	4.01	4.01	3.89	4.01	3.90	4.00	47.16
104	Interest Charged to Construction - Credit	(0.17)	(0.19)	(0.22)	(0.29)	(0.34)	(0.38)	(0.39)	(0.01)	(0.02)	(0.04)	(0.02)	(0.02)	(2.10)
105	Other Interest Expense	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
106	Asset Retirement Obligation													
107	Other Deductions	0.05	0.05	0.05	0.05	0.04	0.06	0.04	0.04	0.04	0.05	0.05	0.07	0.59
108														
109	**TOTAL COST OF ELECTRIC SERVICE**	[redacted]												
110														
111	**OPERATING MARGINS**	4.99	3.38	(2.23)	(6.82)	(4.38)	1.75	3.56	3.45	0.43	(1.94)	0.93	3.65	6.77
112														
113	Interest Income	0.17	0.17	0.17	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	1.95
114	Allowance For Funds Used During Construction													
115	Income (Loss) From Equity Investments													
116	Other Non-Operating Income (Net)													
117	Generation and Transmission Capital Credits													
118	Other Capital Credits and Patronage Dividends	0.00	0.00	2.71	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.71
119	Extraordinary Items													
120	**NET PATRONAGE CAPITAL OR MARGIN**	5.15	3.55	0.64	(6.65)	(4.22)	1.91	3.73	3.61	0.59	(1.78)	1.09	3.81	11.42
121														
122														

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		2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	2014 September	2014 October	2014 November	2014 December	2014 Total
123	IV. Balance Sheet (Millions of $)													
124	Total Utility Plant in Service	2,049.94	2,050.62	2,053.81	2,065.17	2,072.74	2,074.16	2,075.48	2,139.74	2,142.64	2,145.96	2,146.14	2,146.25	2,146.25
125	Construction Work in Progress	77.36	82.55	87.83	93.13	98.46	101.21	101.50	40.00	40.00	40.00	40.00	40.00	40.00
126	Total Utility Plant	2,127.30	2,133.18	2,141.64	2,158.31	2,171.20	2,175.37	2,176.98	2,179.74	2,182.64	2,185.96	2,186.14	2,186.25	2,186.25
127	Accum. Provision for Depreciation and Amort.	1,004.91	1,008.64	1,011.58	1,011.96	1,013.58	1,017.16	1,020.78	1,023.92	1,027.15	1,030.26	1,034.37	1,038.49	1,038.49
128	NET UTILITY PLANT	1,122.39	1,124.53	1,130.06	1,146.34	1,157.62	1,158.21	1,156.20	1,155.82	1,155.48	1,155.70	1,151.77	1,147.76	1,147.76
129														
130	Non-Utility Property (Net)													
131	Invest. In Assoc. Org - Patronage Capital	4.15	4.15	4.32	4.32	4.32	4.32	4.32	4.32	4.32	4.32	4.32	4.32	4.32
132	Invest. In Assoc. - Other - General Funds	42.55	42.22	42.22	42.22	41.89	41.89	41.89	41.54	41.54	41.54	41.20	41.20	41.20
133	Other Investments	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
134	Special Funds	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05
135	Special Funds (Transition Reserve)	35.13	35.14	35.15	35.16	35.17	35.18	35.19	35.20	35.20	35.21	35.22	35.23	35.23
136	Special Funds (Economic Reserve)	50.96	48.04	45.35	43.08	40.56	37.35	34.44	31.38	28.79	26.64	24.29	21.29	21.29
137	Special Funds (Rural Economic Reserve)	65.70	65.79	65.89	65.99	66.10	66.20	66.30	66.40	66.50	66.61	66.71	66.81	66.81
138	TOTAL OTHER PROP. AND INVESTMENTS	199.56	196.41	194.00	191.83	189.09	185.99	183.19	179.90	177.42	175.38	172.79	169.91	169.91
139														
140	Cash - General Funds	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
141	Cash - Construction Funds - Trustee													
142	Special Deposits	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60
143	Temporary Investments	94.81	96.74	106.45	92.45	72.43	68.87	73.24	72.99	80.87	84.31	84.60	80.95	80.95
144	Accounts Receivable - Sales of Energy (Net)	44.81	40.23	38.60	34.84	36.62	40.65	42.76	43.48	39.45	39.69	39.55	43.40	43.40
145	Accounts Receivable - Other (Net)	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22
146	Fuel Stock	33.56	33.78	34.02	34.08	34.03	34.09	34.14	34.16	34.19	34.22	34.24	34.24	34.24
147	Materials and Supplies - Other	26.96	27.02	27.09	27.15	27.22	27.28	27.35	27.41	27.48	27.55	27.61	27.68	27.68
148	Prepayments	3.86	3.53	3.21	2.88	2.56	2.23	1.91	1.58	1.26	0.93	0.61	4.38	4.38
149	Other Current and Accrued Assets	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71
150	TOTAL CURRENT AND ACCRUED ASSETS	206.53	203.84	211.90	193.94	175.39	175.67	181.93	182.16	185.78	189.23	189.14	193.18	193.18
151														
152	Unamortized Debt Discount & Extraor. Prop. Losses	4.80	4.77	4.73	4.70	4.67	4.63	4.60	4.57	4.54	4.50	4.47	4.44	4.44
153	Regulatory Assets	6.01	5.87	5.73	5.58	5.44	5.30	5.16	5.02	4.87	4.73	4.59	4.45	4.45
154	Other Deferred Debits	2.37	2.36	2.29	2.24	2.23	2.17	2.25	2.23	2.16	2.12	2.08	2.03	2.03
155	Accumulated Deferred Income Taxes	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
156														
157	TOTAL ASSETS AND OTHER DEBITS	1,541.66	1,537.78	1,548.71	1,544.64	1,534.44	1,531.97	1,533.33	1,529.70	1,530.26	1,531.67	1,524.84	1,521.76	1,521.76
158														

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159														
160	TOTAL MARGINS & EQUITY	407.38	410.92	411.57	404.92	400.70	402.61	406.33	409.94	410.52	408.75	409.84	413.65	413.65
161														
162	Long-Term Debt - RUS	218.14	218.14	220.11	220.12	220.12	222.15	222.16	222.16	224.24	224.25	224.25	226.36	226.36
163	Long-Term Debt - Other	734.10	731.05	738.14	738.14	735.06	737.25	737.25	734.15	735.83	735.83	732.71	730.73	730.73
164	TOTAL LONG-TERM DEBT	952.24	949.19	958.26	958.27	955.19	959.40	959.41	956.31	960.07	960.08	956.96	957.09	957.09
165														
166	Notes Payable	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
167	Accounts Payable	23.37	21.56	25.68	27.36	26.29	23.22	23.01	23.53	22.83	24.80	22.23	20.93	20.93
168	Accounts Payable (TIER Rebate)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
169	Taxes Accrued	0.58	0.93	1.28	1.63	1.98	2.33	2.68	0.75	1.10	1.46	1.17	0.96	0.96
170	Interest Accrued	5.11	5.08	4.46	7.21	7.48	4.79	5.13	5.42	4.40	7.23	7.48	4.76	4.76
171	Other Current and Accrued Liabilities	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29
172														
173	TOTAL CURRENT AND ACCRUED LIAB.	37.35	35.86	39.71	44.50	44.05	38.63	39.12	37.99	36.62	41.77	39.17	34.95	34.95
174														
175	Deferred Credits	1.80	1.68	1.56	1.45	1.34	1.22	1.10	0.98	0.98	0.98	0.99	1.01	1.01
176	Deferred Credits (Economic Reserve)	50.96	48.04	45.35	43.08	40.56	37.35	34.44	31.38	28.79	26.64	24.29	21.29	21.29
177	Deferred Credits (Rural Economic Reserve)	65.70	65.79	65.89	65.99	66.10	66.20	66.30	66.40	66.50	66.61	66.71	66.81	66.81
178	Accumulated Operating Provisions	26.24	26.30	26.37	26.44	26.50	26.57	26.63	26.70	26.77	26.83	26.90	26.97	26.97
179	Obligation under Capital Leases - Noncurrent													
180														
181	TOTAL LIABILITIES AND OTHER CREDITS	1,541.66	1,537.78	1,548.71	1,544.64	1,534.44	1,531.97	1,533.33	1,529.70	1,530.26	1,531.67	1,524.84	1,521.76	1,521.76
182														

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		2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	2014 September	2014 October	2014 November	2014 December	2014 Total
183														
184	**V. Cash Flow Statement (Millions of $)**													
185	Operating Receipts													
186	Rural	15.88	13.80	12.17	9.56	10.81	13.85	15.41	15.84	12.33	10.24	11.68	15.61	157.17
187	Large Industrial	3.80	3.67	3.82	3.74	3.77	3.72	4.10	4.08	3.88	3.96	3.91	3.97	46.42
188	Smelters	15.99	14.52	16.07	15.66	16.18	15.71	16.21	16.35	16.00	16.41	15.83	16.27	191.19
189	Offsystem	[redacted]												
190	Lease Income													
191	Other Operating Revenues	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	3.70
192	Gain on Sale of Allowances	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
193	Other	0.00	0.00	2.71	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.71
194	Interest Earnings	0.17	0.17	0.17	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	1.95
195	Total Receipts	[redacted]												
196														
197	Operating Disbursements													
198	PPA	[redacted]												
199	Fuel Costs													
200	Fuel Costs (Labor & Exp)													
201	Domtar	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
202	Power Supply (P Power, APM, Cogen, & TVA Tran)	[redacted]												
203	Production O&M													
204	Transmission O&M													
205	A&G													
206	Working Capital	(0.73)	(3.78)	(6.27)	(6.12)	1.84	6.43	1.64	1.47	(4.01)	(2.40)	2.04	9.13	(0.76)
207	Other	(0.13)	(0.14)	(0.14)	(0.14)	(0.14)	(0.12)	(0.14)	(0.14)	(0.14)	(0.14)	(0.14)	(0.14)	(1.62)
208	Total Disbursements	[redacted]												
209														
210	Operating Receipts less Disbursements	9.91	11.64	11.78	4.79	(0.83)	(0.21)	6.82	7.11	10.21	6.77	4.92	0.08	73.00

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		2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	2014 September	2014 October	2014 November	2014 December	2014 Total
211														
212	Capital Expenditures													
213	Generation	[redacted]												
214	Transmission	0.22	0.33	0.33	0.39	0.38	0.33	0.17	0.36	0.88	0.61	0.18	0.10	4.30
215	A&G	0.00	0.21	0.10	0.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.55
216	Other / IT	0.00	0.05	0.10	0.31	0.11	0.26	0.22	0.32	0.23	0.04	0.01	0.00	1.64
217	Total Capital Expenditures	[redacted]												
218														
219	Income Taxes from Operations	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
220														
221	Net Pre-Finance Cash Flow	3.28	5.75	2.53	(15.16)	(15.74)	(4.41)	5.22	3.49	6.44	2.44	4.71	(0.05)	(1.50)
222														
223	Financing													
224	Principal	(9.00)	3.05	(7.09)	0.00	3.08	(2.19)	0.00	3.10	(1.69)	0.00	3.13	1.98	(5.63)
225	Interest	3.68	3.70	2.63	1.13	3.74	4.55	3.65	3.71	2.84	1.17	3.65	4.61	39.06
226	Debt Issuance Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.02
227	Line of Credit (Upfront Fee)	0.00	0.00	0.00	0.00	0.00	0.00	0.13	0.00	0.00	0.00	0.00	0.00	0.13
228	Aggregate Debt Service (incl. Line of Credit)	(5.32)	6.75	(4.46)	1.13	6.82	2.36	3.78	6.82	1.15	1.17	6.78	6.61	33.58
229														
230	Post-Finance Cash Flow	8.60	(1.01)	7.00	(16.29)	(22.56)	(6.78)	1.44	(3.32)	5.28	1.28	(2.07)	(6.66)	(35.08)
231														
232	Unwind Transaction													
233	Cash Proceeds													
234	Debt Reduction													
235	Misc. Transaction													
236	Net Before Member Reserves													
237	Station Two O&M Fund													
238	Rural Economic Reserve	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
239	Economic Reserve	3.38	2.95	2.72	2.30	2.54	3.23	2.93	3.09	2.61	2.17	2.37	3.01	33.29
240	Net Before Transition Reserve	3.38	2.95	2.72	2.30	2.54	3.23	2.93	3.09	2.61	2.17	2.37	3.01	33.29
241														

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		2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	2014 September	2014 October	2014 November	2014 December	2014 Total
242	Ending Cash Balances (Incl. Transition Reserve)	129.95	131.89	141.61	127.61	107.60	104.06	108.43	108.19	116.08	119.53	119.83	116.18	116.18
243	Ending Cash Balances excl. Transition Reserve)	94.82	96.75	106.46	92.45	72.43	68.88	73.24	73.00	80.88	84.32	84.61	80.95	80.95
244	Change in Working Capital													
245	Other Property	0.00	(0.33)	0.16	0.00	(0.34)	0.00	0.00	(0.34)	0.00	0.00	(0.35)	0.00	(1.19)
246	Accounts Receivable	2.55	(4.58)	(1.63)	(3.76)	1.78	4.03	2.11	0.72	(4.04)	0.25	(0.15)	3.86	1.15
247	Materials, Supplies & Other	0.06	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.79
248	Prepayments	(0.33)	(0.33)	(0.33)	(0.33)	(0.33)	(0.33)	(0.33)	(0.33)	(0.33)	(0.33)	(0.33)	3.77	0.20
249	Other Current Assets	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
250	Accounts Payable	(3.18)	1.81	(4.12)	(1.68)	1.07	3.07	0.21	(0.51)	0.70	(1.97)	2.57	1.30	(0.75)
251	Taxes Accrued	0.23	(0.35)	(0.35)	(0.35)	(0.35)	(0.35)	(0.35)	1.93	(0.35)	(0.35)	0.29	0.21	(0.15)
252	Other Accruals	(0.07)	(0.07)	(0.07)	(0.07)	(0.07)	(0.07)	(0.07)	(0.07)	(0.07)	(0.07)	(0.07)	(0.07)	(0.80)
253	Total	(0.73)	(3.78)	(6.27)	(6.12)	1.84	6.43	1.64	1.47	(4.01)	(2.40)	2.04	9.13	(0.76)
254														

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		2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	2014 September	2014 October	2014 November	2014 December	2014 Total
255														
256	**VI. Cash Flow Statement - Indirect (Millions of $)**													
257														
258	**Cash Flows From Operating Activities:**													
259	Net Margin	5.15	3.55	0.64	(6.65)	(4.22)	1.91	3.73	3.61	0.59	(1.78)	1.09	3.81	11.42
260	Adjustments to reconcile net margin to net cash													
261	provided by operating activities:													
262	Depreciation and amortization	3.94	3.94	3.95	3.95	3.98	4.00	4.00	4.01	4.14	4.15	4.16	4.16	48.37
263	Interest compounded - RUS Series A Note	0.01	0.00	0.00	0.01	0.00	0.00	0.01	0.00	0.00	0.01	0.00	0.00	0.05
264	Interest compounded - RUS Series B Note	0.00	0.00	1.97	0.00	0.00	2.02	0.00	0.00	2.08	0.00	0.00	2.11	8.18
265	Noncash member rate mitigation revenue	(3.36)	(2.93)	(2.69)	(2.27)	(2.51)	(3.21)	(2.91)	(3.06)	(2.46)	(2.03)	(2.22)	(2.84)	(32.50)
266	Changes in certain assets and liabilities:													
267	Other property	0.00	0.33	(0.16)	0.00	0.34	0.00	0.00	0.34	0.00	0.00	0.35	0.00	1.19
268	Accounts receivable	(2.55)	4.58	1.63	3.76	(1.78)	(4.03)	(2.11)	(0.72)	4.04	(0.25)	0.15	(3.86)	(1.15)
269	Inventories	(0.44)	(0.29)	(0.30)	(0.12)	(0.02)	(0.13)	(0.11)	(0.09)	(0.09)	(0.10)	(0.08)	(0.07)	(1.84)
270	Prepayments	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	(3.77)	(0.20)
271	Other current assets	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
272	Accounts payable	3.18	(1.81)	4.12	1.68	(1.07)	(3.07)	(0.21)	0.51	(0.70)	1.97	(2.57)	(1.30)	0.75
273	Taxes accrued	(0.23)	0.35	0.35	0.35	0.35	0.35	0.35	(1.93)	0.35	0.35	(0.29)	(0.21)	0.15
274	Other accruals	0.20	(0.11)	(0.68)	2.62	0.04	(2.93)	0.10	0.40	(0.89)	2.94	0.37	(2.56)	(0.50)
275	Net cash provided by operating activities	6.24	7.95	9.15	3.66	(4.57)	(4.76)	3.17	3.40	7.37	5.60	1.27	(4.54)	33.94
276														
277	**Cash Flows From Investing Activities:**													
278	Capital expenditures	(6.64)	(5.90)	(9.25)	(19.95)	(14.91)	(4.20)	(1.60)	(3.62)	(3.77)	(4.32)	(0.21)	(0.13)	(74.50)
279	Net proceeds from restricted investments	3.37	2.94	2.71	2.29	2.53	3.22	2.93	3.08	2.60	2.16	2.36	3.00	33.19
280	Net cash provided by (used in) inv. Activities	(3.27)	(2.96)	(6.54)	(17.66)	(12.37)	(0.98)	1.32	(0.54)	(1.18)	(2.16)	2.15	2.88	(41.32)

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		2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	2014 September	2014 October	2014 November	2014 December	2014 Total
281														
282	**Cash Flows From Financing Activities:**													
283	Net principal payments on debt obligations	9.00	(3.05)	7.09	0.00	(3.08)	2.19	0.00	(3.10)	1.69	0.00	(3.13)	(1.98)	5.63
284	Debt issuance cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.02)	(0.02)
285	Line of Credit (Upfront Fee)	0.00	0.00	0.00	0.00	0.00	0.00	(0.13)	0.00	0.00	0.00	0.00	0.00	(0.13)
286	Net cash provided by (used in) Financihng Activities	9.00	(3.05)	7.09	0.00	(3.08)	2.19	(0.13)	(3.10)	1.69	0.00	(3.13)	(2.00)	5.48
287														
288	Net increase (decrease) in cash	11.97	1.93	9.71	(14.00)	(20.02)	(3.55)	4.36	(0.25)	7.88	3.44	0.29	(3.66)	(1.90)
289														
290	**Cash and Cash Equivalents - Beg. of Period**													82.85
291	**Cash and Cash Equivalents - End of Period**													80.95

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	2013 September	2013 October	2013 November	2013 December	2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	Test Period Total
I. Sales													
Energy (TWH)													
Rural	0.18	0.15	0.18	0.25	0.25	0.21	0.19	0.15	0.17	0.22	0.25	0.24	2.44
Large Industrial	0.08	0.08	0.08	0.08	0.08	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.94
Century	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Alcan	0.26	0.27	0.26	0.27	0.27	0.24	0.27	0.26	0.27	0.26	0.27	0.27	3.16
Market	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Energy Sales	0.68	0.75	0.72	0.75	0.77	0.69	0.66	0.60	0.63	0.68	0.71	0.71	8.34
Demand (MW)													
Rural	416.26	336.41	377.17	494.38	548.56	489.60	425.32	333.27	380.07	479.13	500.79	541.33	5,322.30
Large Industrial	136.42	138.47	138.43	138.60	140.57	139.90	139.11	139.40	138.43	138.53	143.19	143.54	1,674.59
II. Rates, Accrual Based ($ / MWH)													
Rural													
Load Factor (%)	59.69%	61.52%	66.01%	66.76%	62.04%	64.25%	60.26%	62.62%	59.36%	63.85%	66.35%	59.09%	62.82%
Demand ($/ KW-mo.)	16.95	16.95	16.95	16.95	16.95	16.95	16.95	16.95	16.95	16.95	16.95	16.95	16.95
Energy ($/ MWH)	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00
Base Rate ($/ MWH)	69.44	67.03	65.66	64.12	66.72	69.26	67.81	67.59	68.38	66.87	64.34	68.56	67.02
Non-Smelter Non-FAC PPA	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)
FAC	4.70	4.48	4.61	4.67	4.90	5.07	5.22	5.34	5.44	5.64	5.66	5.70	5.14
Environmental Surcharge	4.35	4.13	3.72	3.42	3.73	3.88	3.67	3.99	3.94	3.87	3.70	4.55	3.90
Surcredit	(1.91)	(2.14)	(1.91)	(1.54)	(1.50)	(1.64)	(1.84)	(2.15)	(2.02)	(1.64)	(1.51)	(1.56)	(1.74)
Total	7.14	6.47	6.42	6.55	7.13	7.32	7.05	7.18	7.37	7.87	7.85	8.69	7.30
Economic Reserve	(10.35)	(9.68)	(9.63)	(9.76)	(10.34)	(10.53)	(10.26)	(10.39)	(10.58)	(11.08)	(9.06)	(9.90)	(10.11)
Rural Economic Reserve	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Effective Rate ($/ MWH)	65.45	63.04	61.67	60.13	62.73	65.27	63.81	63.60	64.38	62.88	62.35	66.56	63.43

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		2013 September	2013 October	2013 November	2013 December	2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	Test Period Total
34	**Large Industrial**													
35	Load Factor (%)	78.20%	76.55%	77.18%	76.59%	75.71%	79.04%	77.68%	76.94%	76.72%	77.06%	77.88%	76.94%	77.20%
36	Demand ($/ KW-mo.)	12.41	12.41	12.41	12.41	12.41	12.41	12.41	12.41	12.41	12.41	12.41	12.41	12.41
37	Energy ($/ MWH)	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00
38	Power Factor Penalty/ Demand Cr. (Lrg. Ind.)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
39	Base Rate ($/ MWH)	52.04	51.79	52.33	51.78	52.03	53.37	51.47	52.40	51.74	52.37	51.42	51.68	52.02
40														
41	Non-Smelter Non-FAC PPA	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)
42	FAC	4.70	4.48	4.61	4.67	4.90	5.07	5.22	5.34	5.44	5.64	5.66	5.70	5.12
43	Environmental Surcharge	3.33	3.25	3.01	2.80	2.96	3.05	2.85	3.16	3.06	3.10	3.02	3.52	3.09
44	Surcredit	(1.91)	(2.14)	(1.91)	(1.54)	(1.50)	(1.64)	(1.84)	(2.15)	(2.02)	(1.64)	(1.51)	(1.56)	(1.78)
45	Total	6.12	5.59	5.71	5.94	6.37	6.49	6.23	6.35	6.48	7.09	7.17	7.66	6.44
46	Economic Reserve	(9.33)	(8.80)	(8.92)	(9.15)	(9.58)	(9.70)	(9.44)	(9.56)	(9.69)	(10.31)	(8.38)	(8.87)	(9.30)
47	TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
48	Effective Rate ($/ MWH)	48.05	47.80	48.34	47.78	48.04	49.37	47.48	48.41	47.75	48.37	49.43	49.69	48.38
49														
50	**Non-Smelter Member Blend**													
51	Base Rate ($/ MWH)	64.21	61.87	61.66	61.12	63.22	65.13	62.96	62.44	63.05	63.12	61.09	64.23	62.84
52														
53	Non-Smelter Non-FAC PPA	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)
54	FAC	4.70	4.48	4.61	4.67	4.90	5.07	5.22	5.34	5.44	5.64	5.66	5.70	5.14
55	Environmental Surcharge	4.04	3.83	3.51	3.27	3.54	3.66	3.43	3.71	3.66	3.67	3.53	4.29	3.67
56	Surcredit	(1.91)	(2.14)	(1.91)	(1.54)	(1.50)	(1.64)	(1.84)	(2.15)	(2.02)	(1.64)	(1.51)	(1.56)	(1.75)
57	Total	6.83	6.17	6.21	6.40	6.95	7.10	6.81	6.90	7.08	7.67	7.68	8.43	7.06
58	Economic Reserve	(10.05)	(9.38)	(9.42)	(9.61)	(10.16)	(10.31)	(10.02)	(10.11)	(10.29)	(10.88)	(8.89)	(9.64)	(9.89)
59	Rural Economic Reserve	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
60	TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61	Effective Rate ($/ MWH)	60.22	57.88	57.67	57.13	59.23	61.13	58.97	58.44	59.06	59.12	59.10	62.23	59.23
62														

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		2013 September	2013 October	2013 November	2013 December	2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	Test Period Total
63	**Smelters**													
64	Base Rate	47.60	47.60	47.60	47.60	47.60	47.60	47.60	47.60	47.60	47.60	47.60	47.60	47.60
65	TIER Adjustment	2.95	2.95	2.95	2.95	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94
66	Total	50.55	50.55	50.55	50.55	50.54	50.54	50.54	50.54	50.54	50.54	50.54	50.54	50.54
67	Non-FAC PPA	(0.35)	(0.34)	(0.35)	(0.42)	(0.41)	(0.35)	(0.36)	(0.31)	(0.34)	(0.38)	(0.41)	(0.40)	(0.37)
68	FAC	4.70	4.48	4.61	4.67	4.90	5.07	5.22	5.34	5.44	5.64	5.66	5.70	5.12
69	Environmental Surcharge	3.03	2.97	2.73	2.56	2.70	2.72	2.62	2.86	2.80	2.81	2.78	3.23	2.82
70	Surcharge	1.88	1.86	1.88	1.86	1.86	1.93	1.86	1.88	1.86	1.88	1.86	1.86	1.87
71	TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
72	Effective Rate ($/ MWH)	59.81	59.52	59.41	59.22	59.59	59.91	59.88	60.32	60.31	60.49	60.43	60.92	59.98
73														
74	Market	[redacted]												

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		2013 September	2013 October	2013 November	2013 December	2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	Test Period Total
75														
76	III. Statement of Operations (Millions of $)													
77														
78	Electric Energy Revenues	[redacted]												
79	Income From Leased Property Net													
80	Other Operating Revenue and Income	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	3.70
81	TOTAL OPER. REVENUES & PAT. CAPITAL	[redacted]												
82														
83	Operating Expense-Production-Excluding Fuel	[redacted]												
84	Operating Expense-Production-Fuel													
85	Operating Expense-Other Power Supply													
86	Operating Expense-Transmission													
87	Operating Expense-RTO/ISO													
88	Operating Expense-Distribution													
89	Operating Expense-Customer Accounts													
90	Operating Expense-Customer Service and Information													
91	Operating Expense-Sales													
92	Operating Expense-Administrative and General													
93	TOTAL OPERATION EXPENSE													
94														
95	Maintenance Expense-Production	[redacted]												
96	Maintenance Expense-Transmission													
97	Maintenance Expense-Distribution													
98	Maintenance Expense-General Plant													
99	TOTAL MAINTENANCE EXPENSE													
100														

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		2013 September	2013 October	2013 November	2013 December	2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	Test Period Total
101	Depreciation and Amortization Expense	3.64	3.65	3.66	3.66	3.66	3.67	3.67	3.68	3.69	3.71	3.71	3.71	44.10
102	Taxes	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
103	Interest on Long-Term Debt	3.82	3.97	3.87	3.97	3.91	3.66	3.98	3.90	4.01	3.88	4.01	4.01	46.98
104	Interest Charged to Construction - Credit	(0.06)	(0.10)	(0.14)	(0.18)	(0.17)	(0.19)	(0.22)	(0.29)	(0.34)	(0.38)	(0.39)	(0.01)	(2.48)
105	Other Interest Expense	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
106	Asset Retirement Obligation													
107	Other Deductions	0.04	0.05	0.05	0.07	0.05	0.05	0.05	0.05	0.04	0.06	0.04	0.04	0.59
108														
109	TOTAL COST OF ELECTRIC SERVICE	[redacted]												
110														
111	OPERATING MARGINS	(0.31)	(2.67)	0.22	3.80	4.99	3.38	(2.23)	(6.82)	(4.38)	1.75	3.56	3.45	4.73
112														
113	Interest Income	0.17	0.17	0.17	0.16	0.17	0.17	0.17	0.16	0.16	0.16	0.16	0.16	1.97
114	Allowance For Funds Used During Construction													
115	Income (Loss) From Equity Investments													
116	Other Non-Operating Income (Net)													
117	Generation and Transmission Capital Credits													
118	Other Capital Credits and Patronage Dividends	0.00	0.00	0.00	0.00	0.00	0.00	2.71	0.00	0.00	0.00	0.00	0.00	2.71
119	Extraordinary Items													
120	NET PATRONAGE CAPITAL OR MARGIN	(0.15)	(2.50)	0.38	3.96	5.15	3.55	0.64	(6.65)	(4.22)	1.91	3.73	3.61	9.41
121														
122														

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		2013 September	2013 October	2013 November	2013 December	2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	Test Period Total
123	**IV. Balance Sheet (Millions of $)**													
124	Total Utility Plant in Service	2,040.49	2,046.15	2,048.32	2,048.69	2,049.94	2,050.62	2,053.81	2,065.17	2,072.74	2,074.16	2,075.48	2,139.74	2,139.74
125	Construction Work in Progress	50.29	57.51	64.76	72.20	77.36	82.55	87.83	93.13	98.46	101.21	101.50	40.00	40.00
126	Total Utility Plant	2,090.79	2,103.66	2,113.09	2,120.89	2,127.30	2,133.18	2,141.64	2,158.31	2,171.20	2,175.37	2,176.98	2,179.74	2,179.74
127	Accum. Provision for Depreciation and Amort.	992.12	994.27	997.53	1,001.36	1,004.91	1,008.64	1,011.58	1,011.96	1,013.58	1,017.16	1,020.78	1,023.92	1,023.92
128	NET UTILITY PLANT	1,098.67	1,109.40	1,115.56	1,119.53	1,122.39	1,124.53	1,130.06	1,146.34	1,157.62	1,158.21	1,156.20	1,155.82	1,155.82
129														
130	Non-Utility Property (Net)	4.15	4.15	4.15	4.15	4.15	4.15	4.32	4.32	4.32	4.32	4.32	4.32	4.32
131	Invest. In Assoc. Org - Patronage Capital	42.88	42.88	42.55	42.55	42.55	42.22	42.22	42.22	41.89	41.89	41.89	41.54	41.54
132	Invest. In Assoc. - Other - General Funds	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
133	Other Investments	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05
134	Special Funds	35.10	35.11	35.12	35.13	35.13	35.14	35.15	35.16	35.17	35.18	35.19	35.20	35.20
135	Special Funds (Transition Reserve)	61.91	59.76	57.39	54.30	50.96	48.04	45.35	43.08	40.56	37.35	34.44	31.38	31.38
136	Special Funds (Economic Reserve)	65.29	65.39	65.49	65.60	65.70	65.79	65.89	65.99	66.10	66.20	66.30	66.40	66.40
137	Special Funds (Rural Economic Reserve)													
138	TOTAL OTHER PROP. AND INVESTMENTS	210.40	208.37	205.77	202.79	199.56	196.41	194.00	191.83	189.09	185.99	183.19	179.90	179.90
139														
140	Cash - General Funds	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
141	Cash - Construction Funds - Trustee													
142	Special Deposits	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60
143	Temporary Investments	114.21	105.98	95.16	82.84	94.81	96.74	106.45	92.45	72.43	68.87	73.24	72.99	72.99
144	Accounts Receivable - Sales of Energy (Net)	38.17	38.53	38.41	42.26	44.81	40.23	38.60	34.84	36.62	40.65	42.76	43.48	43.48
145	Accounts Receivable - Other (Net)	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22
146	Fuel Stock	32.76	32.97	33.10	33.18	33.56	33.78	34.02	34.08	34.03	34.09	34.14	34.16	34.16
147	Materials and Supplies - Other	26.70	26.76	26.83	26.89	26.96	27.02	27.09	27.15	27.22	27.28	27.35	27.41	27.41
148	Prepayments	1.17	0.87	0.58	4.18	3.86	3.53	3.21	2.88	2.56	2.23	1.91	1.58	1.58
149	Other Current and Accrued Assets	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71
150	TOTAL CURRENT AND ACCRUED ASSETS	215.54	207.65	196.61	191.89	206.53	203.84	211.90	193.94	175.39	175.67	181.93	182.16	182.16
151														
152	Unamortized Debt Discount & Extraor. Prop. Losses	4.93	4.90	4.86	4.83	4.80	4.77	4.73	4.70	4.67	4.63	4.60	4.57	4.57
153	Regulatory Assets	6.58	6.44	6.29	6.15	6.01	5.87	5.73	5.58	5.44	5.30	5.16	5.02	5.02
154	Other Deferred Debits	2.56	2.51	2.47	2.42	2.37	2.36	2.29	2.24	2.23	2.17	2.25	2.23	2.23
155	Accumulated Deferred Income Taxes	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
156														
157	TOTAL ASSETS AND OTHER DEBITS	1,538.68	1,539.25	1,531.57	1,527.62	1,541.66	1,537.78	1,548.71	1,544.64	1,534.44	1,531.97	1,533.33	1,529.70	1,529.70
158														

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		2013 September	2013 October	2013 November	2013 December	2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	Test Period Total
159														
160	**TOTAL MARGINS & EQUITY**	400.38	397.88	398.26	402.23	407.38	410.92	411.57	404.92	400.70	402.61	406.33	409.94	409.94
161														
162	Long-Term Debt - RUS	216.13	216.14	216.14	218.13	218.14	218.14	220.11	220.12	220.12	222.15	222.16	222.16	222.16
163	Long-Term Debt - Other	730.02	730.02	726.99	725.10	734.10	731.05	738.14	738.14	735.06	737.25	737.25	734.15	734.15
164	**TOTAL LONG-TERM DEBT**	946.14	946.16	943.13	943.23	952.24	949.19	958.26	958.27	955.19	959.40	959.41	956.31	956.31
165														
166	Notes Payable	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
167	Accounts Payable	22.93	24.95	22.37	20.18	23.37	21.56	25.68	27.36	26.29	23.22	23.01	23.53	23.53
168	Accounts Payable (TIER Rebate)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
169	Taxes Accrued	1.01	1.34	1.10	0.81	0.58	0.93	1.28	1.63	1.98	2.33	2.68	0.75	0.75
170	Interest Accrued	4.50	7.29	7.40	4.89	5.11	5.08	4.46	7.21	7.48	4.79	5.13	5.42	5.42
171	Other Current and Accrued Liabilities	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29
172														
173	**TOTAL CURRENT AND ACCRUED LIAB.**	36.73	41.87	39.16	34.17	37.35	35.86	39.71	44.50	44.05	38.63	39.12	37.99	37.99
174														
175	Deferred Credits	2.25	2.15	2.04	1.92	1.80	1.68	1.56	1.45	1.34	1.22	1.10	0.98	0.98
176	Deferred Credits (Economic Reserve)	61.91	59.76	57.39	54.30	50.96	48.04	45.35	43.08	40.56	37.35	34.44	31.38	31.38
177	Deferred Credits (Rural Economic Reserve)	65.29	65.39	65.49	65.60	65.70	65.79	65.89	65.99	66.10	66.20	66.30	66.40	66.40
178	Accumulated Operating Provisions	25.98	26.04	26.11	26.17	26.24	26.30	26.37	26.44	26.50	26.57	26.63	26.70	26.70
179	Obligation under Capital Leases - Noncurrent													
180														
181	**TOTAL LIABILITIES AND OTHER CREDITS**	1,538.68	1,539.25	1,531.57	1,527.62	1,541.66	1,537.78	1,548.71	1,544.64	1,534.44	1,531.97	1,533.33	1,529.70	1,529.70
182														

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		2013 September	2013 October	2013 November	2013 December	2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	Test Period Total
183														
184	**V. Cash Flow Statement (Millions of $)**													
185	Operating Receipts													
186	Rural	11.71	9.71	11.06	14.77	15.88	13.80	12.17	9.56	10.81	13.85	15.41	15.84	154.55
187	Large Industrial	3.69	3.77	3.72	3.77	3.80	3.67	3.82	3.74	3.77	3.72	4.10	4.08	45.65
188	Smelters	15.53	15.97	15.43	15.89	15.99	14.52	16.07	15.66	16.18	15.71	16.21	16.35	189.50
189	Offsystem	[redacted]												
190	Lease Income	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	3.70
191	Other Operating Revenues	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
192	Gain on Sale of Allowances	0.00	0.00	0.00	0.00	0.00	0.00	2.71	0.00	0.00	0.00	0.00	0.00	2.71
193	Other	0.17	0.17	0.17	0.16	0.17	0.17	0.17	0.16	0.16	0.16	0.16	0.16	1.97
194	Interest Earnings	[redacted]												
195	Total Receipts													
196														
197	Operating Disbursements													
198	PPA	[redacted]												
199	Fuel Costs													
200	Fuel Costs (Labor & Exp)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
201	Domtar	[redacted]												
202	Power Supply (P. Power, APM, Cogen, & TVA Tran)													
203	Production O&M													
204	Transmission O&M													
205	A&G	(6.98)	(2.29)	2.08	9.93	(0.73)	(3.78)	(6.27)	(6.12)	1.84	6.43	1.64	1.47	(2.78)
206	Working Capital	(0.14)	(0.14)	(0.14)	(0.14)	(0.13)	(0.14)	(0.14)	(0.14)	(0.14)	(0.12)	(0.14)	(0.14)	(1.62)
207	Other	[redacted]												
208	Total Disbursements													
209														
210	Operating Receipts less Disbursements	11.78	5.31	3.53	(1.30)	9.91	11.64	11.78	4.79	(0.83)	(0.21)	6.82	7.11	70.34

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		2013 September	2013 October	2013 November	2013 December	2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	Test Period Total
211														
212	Capital Expenditures													
213	Generation	[redacted]												
214	Transmission	0.41	0.85	1.58	0.15	0.22	0.33	0.33	0.39	0.38	0.33	0.17	0.36	5.51
215	A&G	0.15	0.20	0.20	0.20	0.00	0.21	0.10	0.25	0.00	0.00	0.00	0.00	1.30
216	Other / IT	0.15	0.11	0.12	0.08	0.00	0.05	0.10	0.31	0.11	0.26	0.22	0.32	1.82
217	Total Capital Expenditures	[redacted]												
218														
219	Income Taxes from Operations	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
220														
221	Net Pre-Finance Cash Flow	5.31	(9.24)	(6.43)	(9.04)	3.28	5.75	2.53	(15.16)	(15.74)	(4.41)	5.22	3.49	(34.44)
222														
223	Financing													
224	Principal	(14.94)	0.00	3.03	1.88	(9.00)	3.05	(7.09)	0.00	3.08	(2.19)	0.00	3.10	(19.07)
225	Interest	2.62	1.17	3.76	4.49	3.68	3.70	2.63	1.13	3.74	4.55	3.65	3.71	38.82
226	Debt Issuance Cost	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02
227	Line of Credit (Upfront Fee)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.13	0.00	0.13
228	Aggregate Debt Service (incl. Line of Credit)	(12.32)	1.17	6.79	6.39	(5.32)	6.75	(4.46)	1.13	6.82	2.36	3.78	6.82	19.90
229														
230	Post-Finance Cash Flow	17.63	(10.41)	(13.22)	(15.43)	8.60	(1.01)	7.00	(16.29)	(22.56)	(6.78)	1.44	(3.32)	(54.34)
231														
232	Unwind Transaction													
233	Cash Proceeds													
234	Debt Reduction													
235	Misc. Transaction													
236	Net Before Member Reserves													
237	Station Two O&M Fund													
238	Rural Economic Reserve	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
239	Economic Reserve	2.57	2.19	2.41	3.12	3.38	2.95	2.72	2.30	2.54	3.23	2.93	3.09	33.42
240	Net Before Transition Reserve	2.57	2.19	2.41	3.12	3.38	2.95	2.72	2.30	2.54	3.23	2.93	3.09	33.42
241														

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		2013 September	2013 October	2013 November	2013 December	2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	Test Period Total
242	Ending Cash Balances (Incl. Transition Reserve)	149.31	141.09	130.28	117.97	129.95	131.89	141.61	127.61	107.60	104.06	108.43	108.19	108.19
243	Ending Cash Balances excl. Transition Reserve)	114.21	105.98	95.17	82.85	94.82	96.75	106.46	92.45	72.43	68.88	73.24	73.00	73.00
244	Change in Working Capital													
245	Other Property	0.00	0.00	(0.33)	0.00	0.00	(0.33)	0.16	0.00	(0.34)	0.00	0.00	(0.34)	(1.18)
246	Accounts Receivable	(11.84)	0.36	(0.12)	3.85	2.55	(4.58)	(1.63)	(3.76)	1.78	4.03	2.11	0.72	(6.53)
247	Materials, Supplies & Other	0.06	0.06	0.06	0.06	0.06	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.77
248	Prepayments	(0.30)	(0.30)	(0.30)	3.61	(0.33)	(0.33)	(0.33)	(0.33)	(0.33)	(0.33)	(0.33)	(0.33)	0.12
249	Other Current Assets	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
250	Accounts Payable	5.48	(2.02)	2.58	2.19	(3.18)	1.81	(4.12)	(1.68)	1.07	3.07	0.21	(0.51)	4.88
251	Taxes Accrued	(0.32)	(0.32)	0.24	0.29	0.23	(0.35)	(0.35)	(0.35)	(0.35)	(0.35)	(0.35)	1.93	(0.06)
252	Other Accruals	(0.06)	(0.06)	(0.07)	(0.07)	(0.07)	(0.07)	(0.07)	(0.07)	(0.07)	(0.07)	(0.07)	(0.07)	(0.79)
253	Total	(6.98)	(2.29)	2.08	9.93	(0.73)	(3.78)	(6.27)	(6.12)	1.84	6.43	1.64	1.47	(2.78)
254														

Big Rivers Electric Corporation
Case No. 2012-00535
Big Rivers Financial Model

		2013 September	2013 October	2013 November	2013 December	2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	Test Period Total
255														
256	**VI. Cash Flow Statement - Indirect (Millions of $)**													
257														
258	**Cash Flows From Operating Activities:**													
259	Net Margin	(0.15)	(2.50)	0.38	3.96	5.15	3.55	0.64	(6.65)	(4.22)	1.91	3.73	3.61	9.41
260	Adjustments to reconcile net margin to net cash													
261	provided by operating activities:													
262	Depreciation and amortization	3.92	3.93	3.94	3.94	3.94	3.94	3.95	3.95	3.98	4.00	4.00	4.01	47.49
263	Interest compounded - RUS Series A Note	0.00	0.01	0.00	0.00	0.01	0.00	0.00	0.01	0.00	0.00	0.01	0.00	0.05
264	Interest compounded - RUS Series B Note	1.96	0.00	0.00	1.99	0.00	0.00	1.97	0.00	0.00	2.02	0.00	0.00	7.95
265	Noncash member rate mitigation revenue	(2.54)	(2.15)	(2.38)	(3.09)	(3.36)	(2.93)	(2.69)	(2.27)	(2.51)	(3.21)	(2.91)	(3.06)	(33.10)
266	Changes in certain assets and liabilities:													
267	Other property	0.00	0.00	0.33	0.00	0.00	0.33	(0.16)	0.00	0.34	0.00	0.00	0.34	1.18
268	Accounts receivable	11.84	(0.36)	0.12	(3.85)	(2.55)	4.58	1.63	3.76	(1.78)	(4.03)	(2.11)	(0.72)	6.53
269	Inventories	(0.35)	(0.27)	(0.20)	(0.14)	(0.44)	(0.29)	(0.30)	(0.12)	(0.02)	(0.13)	(0.11)	(0.09)	(2.46)
270	Prepayments	0.30	0.30	0.30	(3.61)	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	(0.12)
271	Other current assets	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
272	Accounts payable	(5.48)	2.02	(2.58)	(2.19)	3.18	(1.81)	4.12	1.68	(1.07)	(3.07)	(0.21)	0.51	(4.88)
273	Taxes accrued	0.32	0.32	(0.24)	(0.29)	(0.23)	0.35	0.35	0.35	0.35	0.35	0.35	(1.93)	0.06
274	Other accruals	(0.66)	2.84	0.11	(2.52)	0.20	(0.11)	(0.68)	2.62	0.04	(2.93)	0.10	0.40	(0.59)
275	Net cash provided by operating activities	9.16	4.15	(0.23)	(5.79)	6.24	7.95	9.15	3.66	(4.57)	(4.76)	3.17	3.40	31.52
276														
277	**Cash Flows From Investing Activities:**													
278	Capital expenditures	(6.47)	(14.55)	(9.96)	(7.73)	(6.64)	(5.90)	(9.25)	(19.95)	(14.91)	(4.20)	(1.60)	(3.62)	(104.78)
279	Net proceeds from restricted investments	2.56	2.18	2.40	3.11	3.37	2.94	2.71	2.29	2.53	3.22	2.93	3.08	33.32
280	Net cash provided by (used in) inv. Activities	(3.91)	(12.37)	(7.56)	(4.62)	(3.27)	(2.96)	(6.54)	(17.66)	(12.37)	(0.98)	1.32	(0.54)	(71.46)

Big Rivers Electric Corporation
Case No. 2012-00535
Big Rivers Financial Model

		2013 September	2013 October	2013 November	2013 December	2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	Test Period Total
281														
282	**Cash Flows From Financing Activities:**													
283	Net principal payments on debt obligations	14.94	0.00	(3.03)	(1.88)	9.00	(3.05)	7.09	0.00	(3.08)	2.19	0.00	(3.10)	19.07
284	Debt issuance cost	0.00	0.00	0.00	(0.02)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.02)
285	Line of Credit (Upfront Fee)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.13)	0.00	(0.13)
286	Net cash provided by (used in) Financihng Activities	14.94	0.00	(3.03)	(1.90)	9.00	(3.05)	7.09	0.00	(3.08)	2.19	(0.13)	(3.10)	18.92
287														
288	Net increase (decrease) in cash	20.19	(8.23)	(10.82)	(12.32)	11.97	1.93	9.71	(14.00)	(20.02)	(3.55)	4.36	(0.25)	(21.02)
289														
290	**Cash and Cash Equivalents - Beg. of Period**													94.02
291	**Cash and Cash Equivalents - End of Period**													73.00

Big Rivers Electric Corporation
Case No. 2012-00535
Statement of Operations (With and Without Proposed Rate Increase)
Fully Forecasted Test Period (September 2013 to August 2014)

		With Proposed Rate Increase	Without Proposed Rate Increase
1	Electric Energy Revenues	[redacted]	[redacted]
2	Income From Leased Property Net	0	0
3	Other Operating Revenue and Income	3,696,500	3,696,500
4	**TOTAL OPER. REVENUES & PATRONAGE CAPITAL**	[redacted]	[redacted]
5			
6	Operating Expense-Production-Excluding Fuel	[redacted]	[redacted]
7	Operating Expense-Production-Fuel	[redacted]	[redacted]
8	Operating Expense-Other Power Supply	[redacted]	[redacted]
9	Operating Expense-Transmission	[redacted]	[redacted]
10	Operating Expense-RTO/ISO	[redacted]	[redacted]
11	Operating Expense-Distribution	[redacted]	[redacted]
12	Operating Expense-Customer Accounts	[redacted]	[redacted]
13	Operating Expense-Customer Service and Information	[redacted]	[redacted]
14	Operating Expense-Sales	[redacted]	[redacted]
15	Operating Expense-Administrative and General	[redacted]	[redacted]
16	**TOTAL OPERATION EXPENSE**	[redacted]	[redacted]
17			
18	Maintenance Expense-Production	[redacted]	[redacted]
19	Maintenance Expense-Transmission	[redacted]	[redacted]
20	Maintenance Expense-Distribution	[redacted]	[redacted]
21	Maintenance Expense-General Plant	[redacted]	[redacted]
22	**TOTAL MAINTENANCE EXPENSE**	[redacted]	[redacted]
23			
24	Depreciation and Amortization Expense	$ 44,103,016	$ 44,103,016
25	Taxes	885	885
26	Interest on Long-Term Debt	46,983,291	46,983,291
27	Interest Charged to Construction - Credit	(2,480,401)	(2,480,401)
28	Other Interest Expense	0	0
29	Asset Retirement Obligation	0	0
30	Other Deductions	591,094	591,094
31			
32	**TOTAL COST OF ELECTRIC SERVICE**	[redacted]	[redacted]
33			
34	**OPERATING MARGINS**	[redacted]	[redacted]
35			
36	Interest Income	$ 1,974,858	$ 1,974,858
37	Allowance For Funds Used During Construction	0	0
38	Income (Loss) From Equity Investments	0	0
39	Other Non-Operating Income (Net)	0	0
40	Generation and Transmission Capital Credits	0	0
41	Other Capital Credits and Patronage Dividends	2,706,446	2,706,446
42	Extraordinary Items	0	0
43	**NET PATRONAGE CAPITAL OR MARGIN**	[redacted]	[redacted]

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

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

DIRECT TESTIMONY

OF

JOHN WOLFRAM
PRINCIPAL
CATALYST CONSULTING LLC

ON BEHALF OF

BIG RIVERS ELECTRIC CORPORATION

FILED: January 15, 2013

DIRECT TESTIMONY
OF
JOHN WOLFRAM

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DIRECT TESTIMONY
OF
JOHN WOLFRAM

I. INTRODUCTION

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

A. My name is John Wolfram. I am the Principal of Catalyst Consulting LLC. My business address is 3308 Haddon Road, Louisville, Kentucky, 40241.

Q. On whose behalf are your testifying?

A. I am testifying on behalf of Big Rivers Electric Corporation ("Big Rivers").

Q. Briefly describe your education and work experience.

A. I received a Bachelor of Science degree in Electrical Engineering from the University of Notre Dame in 1990 and a Master of Science degree in Electrical Engineering from Drexel University in 1997. I founded Catalyst Consulting LLC in June 2012. From March 2010 through May 2012, I was a Senior Consultant with The Prime Group, LLC. I have developed cost of service studies and rates for numerous electric and gas utilities, including electric distribution cooperatives, generation and transmission cooperatives, municipal utilities and investor-owned utilities. I have performed economic analyses, rate mechanism reviews, ISO/RTO membership evaluations, and wholesale formula rate reviews. I was also employed by the parent companies of Louisville Gas and Electric Company

("LG&E") and Kentucky Utilities Company ("KU"), by the PJM Interconnection, and by the Cincinnati Gas & Electric Company. A more detailed description of my qualifications is included in Exhibit Wolfram-1.

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

A. Yes. I have testified in numerous regulatory proceedings before this Commission. A listing of my testimony in other proceedings is included in Exhibit Wolfram-1.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to: (i) describe Big Rivers' rate classes, (ii) support Big Rivers' revenue requirement; (iii) support several *pro forma* adjustments to the forecast test period results; (iv) support the cost of service study; (v) describe the proposed allocation of the revenue increase to the rate classes; (vi) describe the rate design, new rates, and percentage increase by rate class; and (vii) support certain filing requirements from 807 KAR 5:001.

Q. Are you sponsoring any exhibits?

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

1. Exhibit Wolfram-1 – Qualifications of John Wolfram;

2. Exhibit Wolfram-2 - Revenue Requirements Analysis;
3. Exhibit Wolfram-3 – Cost of Service Study: Functional Assignment and Classification;
4. Exhibit Wolfram-4 – Cost of Service Study: Allocation to Rate Classes;
5. Exhibit Wolfram-5 – Billing Determinants: Present & Proposed Rates;
6. Exhibit Wolfram-6 – Summary of Proposed Increase; and
7. Exhibit Wolfram-7 – Estimate of Retail Rate Increase.

III. CLASSES OF SERVICE

Q. Please describe the customer classes served by Big Rivers.

A. Big Rivers has three major rate classifications – (i) the Rural Delivery Service class, (ii) the Large Industrial Customer class, and (iii) the Smelter class. The Rural Delivery Service rate schedule is the rate schedule under which Big Rivers sells power to its three distribution cooperative members, Jackson Purchase Energy Corporation ("JPEC"), Kenergy Corp. ("Kenergy"), and Meade County Rural Electric Cooperative Corporation. ("Meade County") (collectively, the "Members") for resale to their retail residential, commercial, and small industrial member customers. The majority of the power delivered under the Rural Delivery Service rate schedule is distributed to residential customers. The Large Industrial Customer rate schedule is used to provide power to the Members for resale to 20 large industrial customers – 19 of which are served by Kenergy and one of which is served by JPEC.

Big Rivers also currently provides service to Kenergy for resale to two large aluminum smelters (Alcan Primary Products Corporation ("Alcan") and Century Aluminum of Kentucky General Partnership ("Century")) under special contracts known as the "Smelter Agreements," which were approved by the Commission in its Order dated March 6, 2009, in Case No. 2007-00455 (the "Unwind Proceeding"). Under the Smelter Agreements, the base demand for Alcan is 368 MW, and the base demand for Century is 482 MW. The Base Rate under the Smelter Agreements is determined by applying the Large Industrial Customer rate to a load with a 98 percent load factor, plus a $0.25 per MWh adder. Thus, contractually, any base rate increase to the Smelters is tied to the rates established for the Large Industrial Customer rate class.

On August 20, 2012, Century issued a notice that it was terminating its power contract with Kenergy for Century's Hawesville, Kentucky smelter facility effective August 20, 2013. When the contract termination becomes effective on August 20, 2013, Big Rivers will no longer provide service to Kenergy for resale to Century. Because Big Rivers anticipates the rates proposed in this filing will become effective on or about August 20, 2013, they are calculated on the basis of Big Rivers supplying energy for Alcan but not for Century. In my testimony, references to the "Smelters" will refer to Alcan and Century for periods before August 20, 2013, and to Alcan only on and after August 20, 2013.

Except to the extent that any rate increase in the Large Industrial Customer rate affects the Base Rate in the Smelter Agreements, the other contractual provisions of the Smelter Agreements will be unaffected by the rates proposed in this proceeding. The Smelter Agreements, approved by the Commission in connection with the Unwind Proceeding, were carefully negotiated among the parties and fully recognized the risks and benefits associated with Big Rivers providing service to the Smelters and the risks and benefits of the Smelters receiving service from Big Rivers.

IV. REVENUE REQUIREMENT

Q. Please describe how Big Rivers' proposed revenue increase was determined.

A. Big Rivers is proposing a general adjustment in rates supported by a fully forecasted test period. The proposed revenue increase was determined by analyzing the revenue deficiency based on financial results for the fully forecasted test period. The revenue deficiency was determined as the difference between (i) Big Rivers' adjusted net margins for the forecasted test period without reflecting a general adjustment in rates, and (ii) Big Rivers' net margin requirement necessary to provide a Times Interest Earned Ratio ("TIER") of 1.24 as defined in the Smelter Agreements ("Contract TIER") for the test period. Based on the forecasted test year, the revenue deficiency is $74,476,120.

Q. Why did Big Rivers choose to support the proposed rate increase with the fully forecasted test period?

A. The fully forecasted test period was selected because it is the first full twelve calendar months following the termination of the Century contract. Thus it is representative of Big Rivers' expected financial condition after that date. The fully forecasted test period is better suited than the historic test period for capturing the significant changes to Big Rivers' operations and financial performance that will result from the Century contract termination.

Q. What are the fully forecasted test period and base period for the rate case application?

A. The fully forecasted test period for the filing is the 12 months ended August 31, 2014. Consistent with KRS 278.192, the forecasted test period used to determine revenue requirements in this proceeding corresponds to the first 12 consecutive calendar months the proposed increase would be in effect after the maximum suspension period for the proposed rates. According to KRS 278.190, the maximum suspension period is six months for a general adjustment in rates supported by a fully forecasted test period. Because the effective date of the Big Rivers' proposed rates is February 18, 2013, the first 12 consecutive calendar months after the 6 month suspension period corresponds to the 12 months beginning September 1, 2013, and ending on August 31, 2014.

The base period for the filing is the 12 months ending April 30, 2013. The base period consists of six months of actual historical data and six months of estimated data. KRS 278.192(2)(a) requires that any rate case application utilizing a forecasted test period must include a base period which begins not more than nine months prior to the date of the filing, consisting of not less than six months of actual historical data and not more than six months of estimated data. Because Big Rivers' proposed base period, which begins May 1, 2012, includes not less than six months of actual historical data (May 2012 through October 2012), includes no more than six months of estimated data (November 2012 through May 2013), and begins less than nine months prior to the filing date in this proceeding, its proposed base period is in compliance with the requirements for a forecasted test year set forth in KRS 278.192(2)(a).

Q. Do any of your analyses or exhibits include the effects of Century demand, energy, revenues, or other charges?

A. No. Because the fully forecasted test period begins after the effective date of the Century contract termination, none of the analyses I present include the effects of Century on Big Rivers' operations or financials.

Q. Why is Big Rivers proposing that the new rates become effective on February 18, 2013, when the Century contract termination does not take effect until August 20, 2013?

A. The effective date for Big Rivers' proposed tariffs was chosen with the expectation that the Commission will suspend the proposed tariffs for the full six months allowed by KRS 278.190(2) in order to conduct discovery and hold a hearing concerning the reasonableness of the proposed rates, and that the proposed rates will be in effect by order of the Commission or pursuant to KRS 278.190(2) no later than the termination date of Century Aluminum of Kentucky General Partnership's retail service contract. This is a necessary risk management step for Big Rivers to minimize its significant financial exposure to the revenue shortfall resulting from the Century contract termination.

Q. Have you prepared an exhibit that shows how Big Rivers' revenue deficiency is calculated?

A. Yes. Exhibit Wolfram-2 shows the calculation of Big Rivers' revenue deficiency.

Q. Please explain Exhibit Wolfram-2 in detail.

A. The purpose of Exhibit Wolfram-2 is to calculate the difference between Big Rivers' adjusted net margin for the forecasted test year and the margin necessary for Big Rivers to achieve a 1.24 Contract TIER. The exhibit begins with Total Operating Revenue and Patronage Capital Without Proposed Rate Increase from Big Rivers' budget for the 12 months ended August 31, 2014 (line 1). This amount is obtained from Exhibit Siewert-3. Three *pro forma* adjustments are applied to Operating Revenue, as shown on lines 4 through 6 of the exhibit. Big Rivers' Adjusted Revenue, as adjusted to reflect the three *pro forma* revenue adjustments, is shown on line 9.

The Total Cost of Service from Big Rivers' budget is shown on line 11. In the context of Big Rivers' budget and financial reports, Total Cost of Service includes operation expenses, maintenance expenses, depreciation and amortization expenses, taxes, interest expenses on long-term debt, other interest expenses, and other deductions. Total Cost of Service is then adjusted to reflect *pro forma* adjustments shown on lines 14 through 25 of the exhibit. Adjusted Cost of Service, as adjusted to reflect the pro forma expense adjustments, is shown on line 28. Adjusted Operating Margins (line 30) is calculated by subtracting Adjusted Cost of Service (line 28) from Adjusted Revenue (line 9). Interest income (line 33), other non-operating income (line 34), and other capital credits/patronage dividends (line 35) are added to Adjusted Operating Margins (line 30) to determine Big Rivers' Adjusted Net Margin (Deficit) on line 41.

The Revenue Deficiency is calculated at the bottom of Exhibit Wolfram-2. To calculate the revenue deficiency, Big Rivers must first remove the interest income on the Transition Reserve; I explain this below. Based on a 1.24 Contract TIER and net of the interest on the Transition Reserve, Big Rivers has a net margin requirement of $11,381,405. Because the adjusted net margin before applying the Contract TIER is ($63,200,130) (line 49), and the margin requirement is $11,381,405 (line 51), Big Rivers' total revenue deficiency is $74,476,120 (line 53).

Q. Why is it appropriate for Big Rivers to remove the effects of interest on the Transition Reserve when it calculates the revenue deficiency?

A. Section 4.7 of the Smelter Agreements specifies a TIER Adjustment Charge for both Smelters. Section 4.7.5(f) provides:

> It shall be assumed that: The Rural Economic Reserve, the Economic Reserve, and the Transition Reserve shall not generate any revenue or tax liability and the application of funds from the Rural Economic Reserve, the Economic Reserve, or the Transition Reserve shall not result in any change in the Net Margins of Big Rivers.

Thus, pursuant to the Smelter Agreements, Big Rivers' TIER is adjusted to exclude from the margin calculation any interest income on the Transition Reserve account. Big Rivers budgets interest income on the Transition

Reserve for the test period. This interest income is removed in the calculation of Contract TIER. This is consistent with the Commission's November 17, 2011, Order in Case No. 2011-00036.

Q. Is it appropriate for Big Rivers to establish a revenue requirement based on Contract TIER?

A. Yes. It is appropriate to use the Contract TIER to establish the revenue requirement for Big Rivers because the Smelter Agreements base the TIER Adjustment Charge on Contract TIER. The Smelter Agreements effectively establish a "bandwidth" for the Smelters' TIER Adjustment Charge. If Big Rivers achieves greater than the 1.24 Contract TIER, then Big Rivers would be subject to first reducing the TIER Adjustment Charge to the Smelters until it reaches $0, and then rebating any remaining excess margins (if any) to the Smelters under the Smelter Agreements and to the Rural Delivery Service and Large Industrial Customer classes (the "Non-Smelters") under Big Rivers' Rebate Adjustment tariff rider (subject to approval by the Big Rivers Board of Directors and the Commission). Thus, Big Rivers is effectively capped at a 1.24 Contract TIER, which is a fairly low ceiling for a generation and transmission cooperative, and is why Big Rivers used the Contract TIER in its last base rate case and why it chose to do the same here. Also, in Big Rivers' last rate case, Case No. 2011-00036, the Commission accepted the use of a 1.24 Contract TIER.

Q. Is it required that Big Rivers establish its revenue requirement based on Contract TIER?

A. No. Big Rivers is not prohibited from seeking to set rates based on a TIER that exceeds 1.24, in this or any future proceeding. Big Rivers elected to do so in this case, without prejudice, in consideration of the impact of the magnitude of the proposed increase (largely driven by the Century contract termination) on Member and the remaining smelter's billings. On the other hand, using less than the 1.24 Contract TIER would expose Big Rivers to the financial and operational risks detailed in the Direct Testimony of Ms. Billie J. Richert.

Q. What is the revenue deficiency calculated in Exhibit Wolfram-2?

A. The revenue deficiency shown in Exhibit Wolfram-2 is $74,476,120. This amount is used in the cost of service study and in the design of new rates that I describe later in my testimony.

V. *PRO FORMA* ADJUSTMENTS

Q. Please broadly describe the nature of the *pro forma* adjustments made to Big Rivers' electric operations for the test year ended August 31, 2014, shown in Exhibit Wolfram-2.

A. For the test year ended August 31, 2014, Big Rivers has made adjustments which remove revenues and expenses that are addressed in other rate mechanisms, removed expenses that are ordinarily excluded from rates, and adjusted expenses such that certain non-recurring costs are excluded from rates on a prospective basis.

Q. Please explain the adjustment to operating revenues and expenses shown in Reference Schedule 1.01 of Exhibit Wolfram-2.

A. This adjustment has been made to account for the fuel cost expenses and revenues included in the Fuel Adjustment Clause ("FAC") for the twelve months ended August 31, 2014. Consistent with Commission practice, fuel costs and and revenues included in Big Rivers' FAC have been eliminated. Because Big Rivers is using a fully forecasted test period in this filing, and because Big Rivers assumes perfect rate treatment for the FAC rate mechanism, the revenue and expense values are identical.

Q. Please explain the adjustment to operating revenues and expenses shown in Reference Schedule 1.02 of Exhibit Wolfram-2.

A. This adjustment has been made to remove Environmental Surcharge ("ES") revenues and expenses because these are addressed by a separate rate mechanism. Consistent with the Commission's practice of eliminating the revenues and expenses associated with full-recovery cost trackers, an adjustment was made to eliminate ES revenues and expenses during the test year. The ES provides for full recovery of approved environmental costs that qualify for the surcharge, and thus should be excluded from base rates.

Q. Please explain the adjustment to operating revenues and expenses shown in Reference Schedule 1.03 of Exhibit Wolfram-2.

A. This adjustment has been made to eliminate the expenses and revenues associated with the Non-FAC Purchased Power Adjustment ("Non-FAC PPA") and addressed by a separate rate mechanism. Consistent with the Commission's practice of eliminating the revenues and expenses associated with full-recovery cost trackers, an adjustment was made to eliminate Non-FAC PPA revenues and expenses during the test year.

Q. Please explain the adjustment to operating revenues and expenses shown in Reference Schedule 1.04 of Exhibit Wolfram-2.

A. This adjustment eliminates advertising expenses pursuant to 807 KAR 5:016 that are institutional and promotional in nature, consistent with Commission practice.

Q. Please explain the adjustment to operating revenues and expenses shown in Reference Schedule 1.05 of Exhibit Wolfram-2.

A. This adjustment eliminates lobbying expenses pursuant to 807 KAR 5:016, consistent with Commission practice. The expenses for each month include Big Rivers' costs for an outside firm and for the portions of Big Rivers' internal expenses related to lobbying. The value in May 2014 also includes the portion of National Rural Electric Cooperative Association ("NRECA") dues that NRECA specifies on its invoices as lobbying-related. The budgeted amount for this is $53,017.

Q. Please explain the adjustment to operating revenues and expenses shown in Reference Schedule 1.06 of Exhibit Wolfram-2.

A. This adjustment eliminates economic development expenses pursuant to 807 KAR 5:016, consistent with Commission practice. Big Rivers provides a one-time annual payment to its Members for economic development initiatives, in the total amount of $140,357.

Q. Please explain the adjustment to operating revenues and expenses shown in Reference Schedule 1.07 of Exhibit Wolfram-2.

A. This adjustment eliminates donations expenses pursuant to 807 KAR 5:016, consistent with Commission practice.

Q. Please explain the adjustment to operating revenues and expenses shown in Reference Schedule 1.08 of Exhibit Wolfram-2.

A. This adjustment eliminates Touchstone Energy dues, pursuant to 807 KAR 5:016, consistent with Commission practice. The dues payment is budgeted as a one-time expense in March 2014 in the amount of $132,766.

Q. Please explain the adjustment to operating revenues and expenses shown in Reference Schedule 1.09 of Exhibit Wolfram-2.

A. This adjustment reflects the amortization of rate case expenses from Big Rivers' last rate case, Case No. 2011-00036. The adjustment of $640,753 reflects the amortization of Big Rivers' professional services costs related to the principal case, amortized over a three-year period, as described in the Rehearing Brief of Big Rivers Electric Corporation filed October 1, 2012, in

Case No. 2011-00036. These costs are not presently included in Big Rivers' rates. If the Commission issues an order on rehearing in that docket before the rates proposed in this filing become effective, the amount of the proposed adjustment in this filing may require revision for Big Rivers to address the Commission's findings in that order.

Q. Is Big Rivers proposing a *pro forma* adjustment to amortize the rate case expenses associated with the instant case?

A. No. Big Rivers included the projected rate case expenses for this proceeding in its budget, amortized over a 36 month period beginning in September 2013. The total, unamortized amount is $1,585,977. This is described in detail in the Direct Testimony of Ms. DeAnna M. Speed. Because the amortization of these costs is already included in the fully forecasted test period, no *pro forma* adjustment to test year expenses is proposed.

Q. Please explain the adjustment to operating revenues and expenses shown in Reference Schedule 1.10 of Exhibit Wolfram-2.

A. This adjustment eliminates non-recurring labor expenses at Big Rivers' D. B. Wilson ("Wilson") plant, related to the anticipated lay-up of that facility described in the Direct Testimony of Mr. Robert W. Berry. The calculation of the adjustment eliminates the burdened labor expenses for Wilson plant and plant-related staff included in the 2013 budget in September, October and November. The costs are included in the budget through November 2013 but are non-recurring from a ratemaking standpoint. Specifically, five departments have headcount reductions directly impacted by the lay-up of the Wilson Station. These include Wilson Plant, Wilson IT, Wilson Safety, Budgeting, and Supply Chain. For each of these departments, the burdened labor expenses for September, October and November 2013 were scaled by the ratio of "pre-lay-up" headcount to "post-lay-up" headcount in order to adjust the plant-related burdened labor in total to a representative level on a prospective basis. The total amount of labor and labor overheads included in the budget for those three months, but excluded for ratemaking purposes, is $2,595,458.

Q. Please explain the adjustment to operating revenues and expenses shown in Reference Schedule 1.11 of Exhibit Wolfram-2.

A. This adjustment normalizes annual expenses for certain outside professional services.

First, Big Rivers prepares an Integrated Resource Plan ("IRP") every three years. Big Rivers budgets a total of $445,000 for outside services for this initiative. Due to timing issues, $151,000 is included in the test period, while the remaining costs for the upcoming IRP were budgeted to be incurred prior to the test period. The proposed adjustment normalizes the full cost for the professional services related to the IRP over three years.

Second, Big Rivers prepares a load forecast every two years. Big Rivers budgets $65,000 for this initiative. Due to timing issues, no costs for the load forecast are included in the test period. The proposed adjustment normalizes the full cost for the professional services related to the load forecast over two years.

Third, from time to time, Big Rivers initiates a Transient Stability Study for transmission system reliability purposes. The study is undertaken as system conditions warrant. Big Rivers budgeted $30,000 for this initiative in the test period. Because there is no set periodicity for this study, the proposed adjustment removes this cost from the revenue requirement.

The normalizations of these three initiatives are combined into a single adjustment summarized in Reference Schedule 1.11.

Q. Please explain the adjustment to operating revenues and expenses shown in Reference Schedule 1.12 of Exhibit Wolfram-2.

A. This adjustment adjusts the revenue requirement to ensure that expenses of $1 million for Demand Side Management ("DSM") and energy efficiency programs are included in the revenue requirement and allocated only to the Rural Delivery Service rate class. In Big Rivers' last rate case, Case No. 2011-00036, Big Rivers sought and was granted a $1 million *pro forma* adjustment for its DSM/energy efficiency programs. In 2012, Big Rivers offered ten DSM programs that the Commission approved in its Order dated August 22, 2012, in Case No. 2012-00142. As discussed in the Direct Testimony of Mr. Albert M. Yockey, Big Rivers did not spend the entire $1 million in 2012. For 2013, Big Rivers intends to spend not only the $1 million that was approved in Case No. 2011-00036, but also the amount that was left over from 2012. In total, Big Rivers has budgeted approximately $1.3 million for its DSM/energy efficiency programs in 2013. This adjustment removes the amounts that exceed $1 million from the test period (which includes portions of 2013 and 2014) revenue requirement because these amounts are non-recurring.

VI. COST OF SERVICE STUDY

Q. Did you prepare a cost of service study for Big Rivers based on financial and operating results for the test year?

A. Yes. I prepared a fully allocated, embedded cost of service study based on *pro forma* operating results for the fully forecasted test year beginning September 1, 2013, and ending August 31, 2014. The objective in performing the cost of service study is to assess Big Rivers' overall rate of return on rate base and to determine the relative rates of return that Big Rivers is earning from each rate class. Additionally, the cost of service study provides an indication as to whether each class is contributing its appropriate share of Big River's cost of providing service.

Q. What procedure was used in performing the cost of service study?

A. The three traditional steps of an embedded cost of service study – functional assignment, classification, and allocation – were utilized. The cost of service study was therefore prepared using the following procedure: (1) costs were functionally assigned (functionalized) to the major functional groups; (2) costs were then classified as energy-related or demand-related; and then (3) costs were allocated to the rate classes.

Q. Is this a standard approach used in the electric utility industry?

A. Yes.

Q. Has this approach been used in previous cases before this Commission?

A. Yes. The same approach was employed by Big Rivers in its last rate case, Case No. 2011-00036, and in several cases filed by other utilities in Kentucky.

Q. What functional groups were used in the cost of service study?

A. The functional groups identified in the cost of service study are Production and Transmission costs.

Q. How were costs classified as energy related or demand related in the cost of service study?

A. Classification provides a method of identifying the appropriate cost driver for each functionally assigned cost so that the service characteristics that give rise to the cost can serve as a basis for allocation. Costs classified as energy-related tend to vary with the amount of kilowatt hours consumed. Fuel and purchased power expenses are examples of costs typically classified as energy costs. Costs classified as demand-related tend to vary with the capacity needs of customers, such as the amount of generation or transmission equipment necessary to meet customers' needs.

Production plant costs are classified as demand-related in the cost of service study. Production operation and maintenance ("O&M") expenses are classified using the FERC Predominance Methodology. Under the FERC Predominance Methodology, production O&M accounts that are predominately fixed, i.e., expenses that the FERC has determined to be predominately incurred independently of kilowatt hour levels of output, are classified as demand related. Production O&M accounts that are predominately variable, i.e., expenses that the FERC has determined to vary predominately with output (kWh), are considered to be energy related. The Predominance Methodology has been accepted in FERC proceedings for many years and is a standard methodology for classifying production O&M expenses. For example, *see Public Service Company of New Mexico*, 10 FERC ¶ 63,020 (1980), *Illinois Power Company*, 11 FERC ¶ 63,040 (1980), *Delmarva Power & Light Company,* 17 FERC ¶ 63,044 (1981), and *Ohio Edison Company,* 24 FERC ¶ 63,068 (1983). The Predominance Methodology has also been used in the cost of service studies submitted by Kentucky Utilities and Louisville Gas and Electric Company in Case Nos. 2003-00433, 2003-00434, 2008-000251, 2008-00252, 2009-00548, and 2009-00549, by East Kentucky Power Cooperative in Case No. 2008-00409, and by Big Rivers in Case No. 2011-00036.

Transmission plant costs and transmission O&M expenses are classified as demand-related in the cost of service study. This is the same methodology used to classify these costs in the Midwest Independent Transmission System Operator, Inc. ("MISO") Tariff, approved by FERC, under which transmission service by Big Rivers is provided.

Q. Have you prepared an exhibit showing the results of the functional assignment and classification steps of the cost of service study?

A. Yes. Exhibit Wolfram-3 shows the results of the first two steps of the cost of service study – functional assignment and classification.

Q. In the cost of service model, once costs are functionally assigned and classified, how are these costs allocated to the customer classes?

A. In the cost of service model used in this study, Big Rivers' test-year costs are functionally assigned and classified using what are referred to in the model as "functional vectors." These vectors are multiplied (using scalar multiplication) by the various accounts in order to simultaneously assign costs to the functional groups and cost classifications (demand and energy). Therefore, in the portion of the model included in Exhibit Wolfram-3, Big Rivers' accounting costs are functionally assigned and classified using the explicitly determined functional vectors identified in the analysis and using internally generated functional vectors. The explicitly determined functional vectors, which are primarily used to direct where costs are functionally assigned and classified, are shown on page 14 of Exhibit Wolfram-3.

Internally generated functional vectors are utilized throughout the study to functionally assign costs either on the basis of similar costs or on the basis of internal cost drivers. The internally generated functional vectors are also shown on page 14 of Exhibit Wolfram-3. An example of this process is the Total Plant In Service ("TPIS") vector, which is used to classify plant in service as shown on page 1 of Exhibit Wolfram-3. The functional vector used to allocate a specific cost is identified by the column in the model labeled "Functional Vector" and refers to a vector identified elsewhere in the analysis by the column labeled "Name."

Once costs for all of the major accounts are functionally assigned and classified, the resultant cost matrix for the major cost groupings (e.g., Plant in Service, Rate Base, Operation and Maintenance Expenses) is then transposed and allocated to the customer classes using "allocation vectors" or "allocation factors."

The results of the class allocation step of the cost of service study are included in Exhibit Wolfram-4. The costs shown in the column labeled "Total System" in Exhibit Wolfram-4 were carried forward from the functionally assigned and classified costs shown in Exhibit Wolfram-3. The column labeled "Ref" in Exhibit Wolfram-4 provides a reference to the results included in Exhibit Wolfram-3.

Q. What rate classes are identified in the cost of service study?

A. In the cost of service study, all costs and revenues are fully allocated to the following three rate classes – Rurals, Large Industrials, and Smelters.

Q. How are demand-related costs allocated in the cost of service study?

A. Production and transmission demand-related costs are allocated using a 12CP methodology. With the 12CP methodology, all demand-related costs are allocated on the basis of the projected average demand for each rate class at the time of Big Rivers' system peak (also known as "Coincident Peak" or "CP") for each of the twelve months, pursuant to Big Rivers' load forecast. The methods employed for developing the demand forecast for Big Rivers are described in the Direct Testimony of Ms. Lindsay N. Barron.

Q. How are energy-related costs allocated in the cost of service study?

A. Energy-related costs are allocated on the basis of projected annual kWh sales to each customer class. The energy forecast is described in the Direct Testimony of Ms. Lindsay N. Barron. The energy values are provided in her Exhibit Barron-3.

Q. Please summarize the results of the cost of service study.

A. The following table summarizes the rates of return for each customer class from the cost of service study. The *Pro Forma* Rate of Return (Before Proposed Rate Increase) was calculated by dividing the net utility operating margin by the net cost rate base for each customer class. The net utility operating margin and net cost rate base reflect the *pro forma* adjustments described earlier in my testimony.

Class Rates of Return	
Customer Class	***Pro Forma*** **Rate of Return Before Proposed Rate Increase**
Rurals	-2.37%
Large Industrials	-2.59%
Smelter	-0.01%
Total System	-1.45%

The determination of the actual adjusted rates of return is detailed on page 11 of Exhibit Wolfram-4.

The negative values for *pro forma* rate of return on rate base indicate that expenses exceed revenues. This is the case for each rate class and for Big Rivers in total. Also, any rate class for which the rate of return is greater than the total system rate of return is providing a subsidy to the other rate class(es); any class with a rate of return that is less than the total system rate of return is receiving a subsidy.

It should be emphasized that the adjusted rates of return shown in the above table reflect all *pro forma* revenue and expense adjustments proposed by Big Rivers in its application in this proceeding. Consequently, the rates of return reflect adjustments in revenues and expenses to eliminate the effect of the FAC, the ES and the Non-FAC PPA, which are addressed by separate stand-alone rate mechanisms, as well as all of the other proposed adjustments.

Q. Since the Smelter Base Rate is tied contractually to the Large Industrial base rates, why is the rate of return for the Smelters higher than the rate of return for the Large Industrials?

A. The higher rate of return for the Smelters is to be fully expected due to the special contract rate provisions prescribed in the Smelter Agreements. Under the Smelter Agreements, the Smelters agree to pay a number of charges that are not paid by the Large Industrials or Rurals. These items are detailed in the Direct Testimony of Mr. Travis A. Siewert. In particular, the Smelters agree to pay TIER Adjustment Charges (Section 4.7.1), Surcharges (Section 4.11), and a Base Rate Adder of $0.25 per MWh (Section 1.1.20). These charges were the result of arms-length negotiations between the parties and were developed in recognition of the risks and benefits associated with Big Rivers providing service to the Smelters and the risks and benefits of the Smelters receiving service from Big Rivers. By contract, Big Rivers and the Smelters have agreed that they would not seek any change in the rate formula in the Smelter Agreements. In the cost of service study, the revenues associated with these charges were fully attributed to the Smelters, thus resulting in a higher rate of return for the Smelters.

VII. ALLOCATION OF THE INCREASE

Q. What variables in the rate structures for Big Rivers' classes of service can be adjusted to bring about the proposed revenue increase?

A. The only variables that can be used to collect additional base rate revenues are: (i) the base demand and energy rates for the Rurals and (ii) the base demand and energy rates for Large Industrials. The Smelter rates cannot be directly adjusted; any base rate increase to the Smelters is essentially a by-product of increasing the base rates to the Large Industrials.

Q. Please summarize how Big Rivers proposes to allocate the revenue increase to the classes of service.

A. Big Rivers relied on the results of the cost of service study to determine the allocation of the proposed revenue increase to the classes of service. Specifically, Big Rivers is proposing to allocate the revenue increase in a manner that is designed to eliminate the gap between the rate of return shown in the cost of service study for the Rurals and the rate of return for the other classes on a combined basis. In other words, Big Rivers is proposing to eliminate the subsidy that the Rural rate class receives in total from the Large Industrials and the Smelters. In technical terms, this means that the proposed revenue increase is allocated such that the rate of return for the Rurals is made equivalent to the rate of return for the total system. This is shown on page 12 of Exhibit Wolfram-4, where the Rurals rate of return of 4.18% is equivalent to the total system return of 4.18%.

Q. Does this mean that the rate of return for the Large Industrials and Smelters is also made equivalent to the rate of return for the total system?

A. On a combined basis, yes. Because the Base Rates for the Smelters are linked by contract to the Large Industrial Customer rate, plus the contractual adders described above, the rate of return for the Large Industrials will differ from that of the Smelters, as evident on page 12 of Exhibit Wolfram-4. However, this method of revenue allocation ensures that the rate of return for the combined Large Industrials and Smelters is equal to that of the Rurals. As noted above, the Smelters' Base Rates cannot be adjusted independently from the Large Industrial rates.

Q. Does this mean that Big Rivers is proposing to eliminate the subsidies received by the Rural rate class from the Large Industrial and Smelter rate classes?

A. Yes. Other than the negligible effects of rounding and/or the number of significant digits of the proposed rates, the subsidies to the Rurals are eliminated.

Q. Would any interclass subsidies remain?

A. Yes. Subsidization of the Large Industrials by the Smelters will continue. This is evident from the rates of return shown on page 12 of Exhibit

Wolfram-4. The Large Industrials rate of return is 2.27% and the Smelters rate of return is 4.80%, which indicates that the Smelters are subsidizing the Large Industrials. This is a by-product of the Smelter Agreements.

Q. What is the proposed base rate revenue increase for each rate class?

A. Big Rivers is proposing the following base rate revenue increases: an increase of $40,676,278 to the Rurals; an increase of $8,247,929 to the Large Industrials; and an increase of $25,551,913 to the Smelters. As will be demonstrated later, the Large Industrials and Smelters will experience a significantly lower percentage increase than the Rurals.

Q. What are the class rates of return adjusted to reflect the proposed revenue increases?

A. The following table shows the rates of return from the cost of service study on an adjusted basis before and after the proposed revenue increases:

Class Rates of Return		
Customer Class	***Pro Forma*** **Rate of Return** ***Before*** **Proposed Increase**	***Pro Forma*** **Rate of Return** ***After*** **Proposed Increase**
Rurals	-2.37%	4.18%
Large Industrials	-2.59%	2.27%
Smelters	-0.01%	4.80%
Total System	-1.45%	4.18%

Note that the rates of return on rate base tabulated above represent the returns before interest on long term debt is paid; a majority of the return is needed to cover debt costs. The rate of return is calculated in this manner to provide a clear representation of the contribution that each rate class is making toward providing a return on Big Rivers' total rate base.

This table illustrates that Big Rivers' proposed allocation of the revenue increase eliminates all of the subsidization of the Rural rate class, and that the proposed revenue increase significantly improves Big Rivers' negative rates of return, both for the individual classes and in total.

VIII. RATE DESIGN & IMPACT OF NEW RATES

Q. Have you prepared an exhibit showing the reconstruction of Big Rivers' test-year billing determinants?

A. Yes. The reconstruction of Big Rivers' billing determinants (also sometimes referred to as the "revenue proof" or the "revenues at present and proposed rates") is shown on Exhibit Wolfram-5.

Q. Is Big Rivers proposing any rate design changes to the Rural or Large Industrial rates?

A. No. The only proposed substantive changes are to the demand and energy rate values. Other non-substantive changes to the tariffs – grammatical error correction, etc. – are described in the Direct Testimony of Mr. Albert

M. Yockey, or are otherwise presented in the tariffs behind Tab 8 and Tab 9 of the application.

Q. What are the proposed charges for the Rurals?

A. Big Rivers is proposing to increase the demand charge from \$9.5000 per kW per month to \$16.9500 per kW per month (billed on the basis of CP demand). Big Rivers is proposing to increase the energy charge from \$0.029736 per kWh to \$0.030000 per kWh.

Q. What are the proposed charges for the Large Industrials?

A. Big Rivers is proposing to increase the demand charge from \$10.5000 per kW per month to \$12.4100 per kW per month and to increase the energy charge from \$0.024505 per kWh to \$0.030000 per kWh.

Q. How were these proposed rates calculated?

A. The rates were calculated such that two constraints were met. The first constraint was that the total incremental revenue resulting from the proposed rates must generate the revenue deficiency of \$74,476,120. The second was that the rate of return for the Rurals must be equal to the overall system rate of return. This created a situation where there are four unknowns – Rural energy charge, Rural demand charge, Large Industrial energy charge, and Large Industrial demand charge – but only two equations. To simplify this problem, Big Rivers set the energy charge for both rate classes to \$0.030000 per kWh – an increase of \$0.000264 per kWh for the Rurals and \$0.005495 per kWh for the Large Industrials. This equalizes the charge for the Rurals and Large Industrials and approximates Big Rivers' annual production cost on a per-unit basis. Then, the demand rates for the Rurals and the Large Industrials were revised such that the two constraints on total incremental revenue and rates of return could be met simultaneously. The proposed demand rates of $16.9500 per kW for the Rurals and $12.4100 for the Large Industrials ensures that the incremental revenue of $74,476,120 is produced and that the subsidy to the Rural rate class is eliminated.

Q. Is it reasonable for the energy rate for the Rural rate class to equal the energy rate for the Large Industrial class?

A. Yes. The costs that vary with consumption are equivalent for all classes. This is reasonable because Big Rivers' cost to produce a unit of power does not vary based on which class of customer consumes that unit of energy.

Q. How were the Base Rates for the Smelters determined?

A. As described earlier, the Base Rate rates for the Smelters are derived by applying the Large Industrial rate to a load with a 98 percent load factor, plus a $0.25 per MWh adder. This is shown on page 3 of Exhibit Wolfram-5.

Q. Is Big Rivers proposing to revise the TIER Adjustment Charges billed under Section 4.7.1 of the Smelter Agreements, as was proposed in the last rate case?

A. No. Big Rivers is electing not do so in this case, but it is not prohibited from doing so.

Q. How does the Member Rate Stability Mechanism ("MRSM") affect Member billings?

A. As part of the transaction approved in the Unwind Proceeding, an Economic Reserve of $157 million was established to offset the impact of the FAC and ES on the Non-Smelters. The MRSM draws on the Economic Reserve to offset the monthly impacts of the FAC and ES on the Members' non-Smelter bills. Basically, the MRSM reduces the monthly bills of the Rural and Large Industrial rate classes, in order to mitigate the effect of anticipated FAC and ES expenses on the Non-Smelter rates, until the Economic Reserve is exhausted and the full amounts of FAC and ES are applied without credit to the Rural and Large Industrial monthly billings.

Q. How do the calculations provided in your exhibits treat the MRSM and its impact on Member billings?

A. All of the calculations I have described so far are gross of the effects of the MRSM. In other words, the benefits of the MRSM to the Rurals and Large Industrials are not included in the calculations of the present rates and revenues, proposed rates and revenues, or percentage increases. This is because the Members receive the benefits of the MRSM today, and will continue to do so after the proposed rates become effective.

Q. Is Big Rivers proposing any changes to the operation of the MRSM?

A. No.

Q. What is the estimated impact of the MRSM on monthly bills for the Rurals and Large Industrials?

A. In the test period, the estimated impact of the MRSM on the average Member bill for the Rural rate class is a credit of $0.0101 per kWh and for the Large Industrial rate class is a credit of $0.0093 per kWh.

Q. Is the Rural Economic Reserve Rider ("RER") treated the same as the MRSM in your analyses?

A. Yes. The RER is similar in concept to the MRSM; the RER draws from a Rural Economic Reserve fund that was established at the unwind transaction, in the amount of approximately $61 million, which becomes available to the Rurals only, after the Economic Reserve fund is exhausted. Because the RER operates in the same way as the MRSM, all of the rate impacts in my exhibits were calculated gross of the RER.

Q. Do the proposed rates account for any FAC or ES roll-in that may stem from other proceedings?

A. No. Reviews of the FAC and the ES filings are underway, as described in the Direct Testimony of Mr. Albert M. Yockey. If those proceedings result in any required rate roll-ins, Big Rivers would have to adjust the rates proposed herein accordingly.

Q. Do the proposed rates account for any amounts subject to rehearing in Case No. 2011-00036?

A. As noted earlier, the proposed rates do account for the *pro forma* adjustment detailed in Reference Schedule 1.09 of Exhibit Wolfram-2, to include $640,753 for the amortization of rate case expenses from Big Rivers' last rate case. The proposed rates do not account for any other amounts subject to rehearing in Case No. 2011-00036. Should the Commission issue an order on rehearing in Case No. 2011-00036 that results in base rates that differ from the rates in effect at the time this filing was prepared, Big Rivers would have to adjust the rates proposed herein accordingly.

Q. Do the proposed rates assign all of the DSM expenses to the Rural rate class, consistent with the Commission findings in Case No. 2011-00036?

A. Yes. This is accomplished in the cost of service study, as shown on page 11 of Exhibit Wolfram-4. The *pro forma* adjustment to normalize DSM expenses in Schedule 1.12 is incorporated into the cost of service study in two steps. First, the full test year budget amount of $1,131,314 for DSM expenses is removed. These costs were originally allocated to the classes on a 12CP basis, so the "12CP" allocator is also used to remove this cost. Second, the $1 million amount that is representative on a prospective basis is added back in and allocated entirely to the Rural rate class using the "EnergyR" allocator. Thus, the DSM costs are directly assigned to the Rurals and are limited to the $1 million amount approved by the Commission in Case No. 2011-00036.

Q. Have you prepared an exhibit showing the impact of the proposed rates on *pro forma* revenue?

A. Yes. Exhibit Wolfram-6 shows the increase in revenue by rate class from applying Big Rivers' proposed rates to *pro forma* billing determinants. In this analysis, the billing determinants and revenue reflect the application of the proposed rates to the forecasted demand and energy values by month for the fully forecasted test period of September 1, 2013 through August 31, 2014.

Q. Is the percentage increase for the Rurals representative of the impact that Big Rivers' rate increase will have on its Members' retail rates to their customers?

A. No. The average impact on the Members' retail rates will result in a lower overall percentage increase than what is being proposed by Big Rivers for the wholesale rates. Because the Members' retail rates also include the cost of providing distribution service to their customers, the percentage impact of Big Rivers' rate increase will be diluted at the retail level.

Big Rivers provides an estimate of the impact of its proposed increase on the retail residential customers in Exhibit Wolfram-7. The exhibit shows the calculation of the estimated retail customer bill at various levels of monthly consumption, assuming a distribution system cost adder of $0.033 per kWh, on an all-in basis, for all of the distribution cooperatives. Obviously, this is a very rough estimate of the impact of Big Rivers' proposed increase on retail rates. The actual retail percentage increase will vary by individual distribution cooperative Member depending upon its individual sales characteristics and retail rate structure. Presumably, Big Rivers' Members will be making their own separate filings to reflect Big Rivers' increase in their rates, and in those filings the increases will be quantified with greater specificity and by retail rate classification.

IX. FILING REQUIREMENTS

Q. Have you reviewed the answers provided in Tabs 1-62, which address Big Rivers' compliance with the historical period filing requirements under 807 KAR 5:001 and its various subsections?

A. Yes. I hereby incorporate and adopt those portions of Tabs 1-62 for which I am identified as the sponsoring witness as part of this Direct Testimony.

X. CONCLUSION

Q. Do you have any closing comments?

A. Yes. Big Rivers' negative rates of return in the cost of service study clearly demonstrate that the proposed increase in base rates is necessary for Big Rivers' financial health. Big Rivers' revenue deficiency, based on a Contract TIER of 1.24, is $74,476,120. This increase is necessary to avoid exposing Big Rivers to the financial and operating risks described in the Direct Testimony of Ms. Billie J. Richert. The proposed rates are designed to produce revenues that achieve the revenue requirement. The proposed rates are designed to eliminate the cost of service subsidies currently being provided to the Rural rate class. The rates also reflect the direct assignment of $1 million of DSM expenses to the Rural rate class, consistent with the findings of the Commission in Big Rivers' last rate case. The proposed rates are just and reasonable and should be approved as filed.

Q. Does this conclude your testimony?

A. Yes, it does.

BIG RIVERS ELECTRIC CORPORATION

**APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2012-00535**

VERIFICATION

I, John Wolfram, verify, state, and affirm that I prepared or supervised the preparation of my testimony filed with this Verification, and that testimony is true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

John Wolfram

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by John Wolfram on this the 9 day of January, 2013.

Jay P. Wright
Notary Public, Ky. State at Large
My Commission Expires________

Notary Public, Kentucky State-At-Large
My Commission Expires: July 3, 2014
ID 421951

Exhibit Wolfram-1
Qualifications of John Wolfram

Exhibit Wolfram-1

Qualifications of John Wolfram

QUALIFICATIONS OF JOHN WOLFRAM

Summary of Qualifications

Provides consulting services to numerous investor-owned utilities, rural electric cooperatives, and municipal utilities regarding utility rate and regulatory filings, cost of service and wholesale and retail rate designs; and develops revenue requirements for utilities in general rate cases, including the preparation of analyses supporting pro-forma adjustments and the development of rate base.

Employment

Catalyst Consulting LLC — June 2012 – Present
Principal

Provides consulting services in the areas of tariff development, regulatory analysis, revenue requirements, cost of service, rate design, and other utility regulatory areas.

Provides utility clients assistance regarding regulatory policy and strategy; project management support for utilities involved in complex regulatory proceedings; process audits; state and federal regulatory filing development; cost of service development and support; the development of innovative rates to achieve strategic objectives; unbundling of rates and the development of menus of rate alternatives for use with customers; energy efficiency program development.

Prepared retail and wholesale rate schedules and/or filings submitted to the Federal Energy Regulatory Commission (FERC), state regulatory commissions, and/or Boards of Directors for numerous electric and gas utilities.

The Prime Group, LLC — March 2010 – May 2012
Senior Consultant

E.ON U.S., LLC , Louisville, KY — 1997 - 2010
(Louisville Gas & Electric Company and Kentucky Utilities Company)
Director, Customer Service & Marketing (2006 - 2010)
Manager, Regulatory Affairs (2001 - 2006)
Lead Planning Engineer, Generation Planning (1998 - 2001)
Power Trader, LG&E Energy Marketing (1997 - 1998)

PJM INTERCONNECTION, LLC, Norristown, PA — 1990 - 1993; 1994 - 1997
Project Lead - PJM Wholesale Energy Market Information System

CINCINNATI GAS & ELECTRIC COMPANY, Cincinnati, OH — 1993 - 1994
Electrical Engineer - Energy Management System

Education

Bachelor of Science Degree in Electrical Engineering, University of Notre Dame, 1990
Master of Science Degree in Electrical Engineering, Drexel University, 1997
Leadership Louisville, 2006

Associations

Member, Institute of Electrical and Electronics Engineers (IEEE)
Member, IEEE Power Engineering Society

Expert Witness Testimony

FERC: Submitted remarks and served on expert panel in FERC Docket No. RM01-10-000 on May 21, 2002 in Standards of Conduct for Transmission Providers staff conference, regarding proposed rulemaking on the functional separation of wholesale transmission and bundled sales functions for electric and gas utilities.

Kentucky: Submitted direct testimony for Louisville Gas & Electric Company and Kentucky Utilities Company in Case No. 2002-00029 regarding a Certificate of Public Convenience and Necessity for the acquisition of two combustion turbines.

Submitted direct testimony for Louisville Gas & Electric Company and Kentucky Utilities Company in Case No. 2002-00381 regarding a Certificate of Public Convenience and Necessity for the acquisition of four combustion turbines.

Presented company position for Louisville Gas & Electric Company and Kentucky Utilities Company at public meetings held in Case Nos. 2005-00142 and 2005-00154 regarding routes for proposed transmission lines.

Submitted discovery responses for Louisville Gas & Electric Company and Kentucky Utilities Company in Case No. 2005-00162 regarding the 2005 Joint Integrated Resource Plan.

Submitted discovery responses for Kentucky Utilities in Case No. 2005-00405 regarding the transfer of a utility hydroelectric power plant to a private hydroelectric power developer.

Submitted direct testimony for Louisville Gas & Electric Company and Kentucky Utilities Company in Case No. 2005-00467 and 2005-00472 regarding a Certificate of Public Convenience and Necessity for the construction of transmission facilities.

Submitted direct testimony for Louisville Gas & Electric Company and Kentucky Utilities Company in Case No. 2007-00067 for approval of a proposed Green Energy program and associated tariff riders.

Submitted direct testimony for Louisville Gas & Electric Company and Kentucky Utilities Company in Case No. 2007-00319 for the review, modification, and continuation of Energy Efficiency Programs and DSM Cost Recovery Mechanisms.

Submitted discovery responses for Louisville Gas & Electric Company and Kentucky Utilities Company in Administrative Case No. 2007-00477 regarding an investigation of the energy and regulatory issues in Kentucky's 2007 Energy Act.

Submitted discovery responses for Louisville Gas & Electric Company and Kentucky Utilities Company in Case No. 2008-00148 regarding the 2008 Joint Integrated Resource Plan.

Submitted discovery responses for Kentucky Utilities and/or Louisville Gas & Electric Company in various customer inquiry matters, including Case Nos. 2009-00421, 2009-00312, and 2009-00364.

Submitted direct testimony for Louisville Gas & Electric Company in Case No. 2009-00549 and for Kentucky Utilities Company in Case No. 2009-00548 for adjustment of electric and gas base rates, in support of a new service offering for Low Emission Vehicles, revised special charges, and company offerings aimed at assisting customers or enhancing customer service.

Submitted direct, rebuttal, and rehearing direct testimony on behalf of Big Rivers Electric Corporation in Case No. 2011-00036 regarding revenue requirements and pro forma adjustments in a base rate case.

Submitted direct and rebuttal testimony on behalf of Big Rivers Electric Corporation in Case No. 2012-00063 regarding an Environmental Compliance Plan and Environmental Surcharge rate mechanism.

Virginia: Submitted direct testimony for Kentucky Utilities Company d/b/a Old Dominion Power in Case No. PUE-2002-00570 regarding a Certificate of Public Convenience and Necessity for the acquisition of four combustion turbines.

Exhibit Wolfram-2
Revenue Requirements Analysis

Exhibit Wolfram-2

Revenue Requirements Analysis

BIG RIVERS ELECTRIC CORPORATION
Calculation of Revenue Requirement
Based on Fully Forecasted Test Period
For the 12 Months Ended August 31, 2014

Line	Description	Ref Sched	Amount
1	**Total Oper Revenue & Patronage Capital Without Proposed Rate Increase**	Exh Siewert-3	$ 407,988,345
2			
3	**Adjustments to Revenue**		
4	To Remove Fuel Adjustment Clause Revenue	1.01	$ (33,538,999)
5	To Remove Environmental Surcharge Revenue	1.02	$ (21,321,155)
6	To Remove Non-FAC PPA Revenue	1.03	$ 2,426,432
7	Subtotal	Lines 4-6	$ (52,433,722)
8			
9	Adjusted Revenue	Line 1 + Line 7	$ 355,554,623
10			
11	**Total Cost of Service**	Exh Siewert-3	$ 478,313,780
12			
13	**Adjustments to Cost of Service**		
14	To Remove Fuel Expense Recoverable through the FAC	1.01	$ (33,538,999)
15	To Remove Expenses Recoverable through the ES	1.02	$ (21,321,155)
16	To Remove Expenses Recoverable through the Non-FAC PPA	1.03	$ 2,426,432
17	To Remove Promotional Advertising	1.04	$ (55,756)
18	To Remove Lobbying Expenses	1.05	$ (70,923)
19	To Remove Economic Development Expenses	1.06	$ (140,357)
20	To Remove Donations Expenses	1.07	$ (63,328)
21	To Remove Touchstone Energy dues	1.08	$ (132,766)
22	To Amortize 2011 Rate Case Expenses for Case No. 2011-00036	1.09	$ 640,753
23	To Remove Non-recurring Labor related to Wilson Layup	1.10	$ (2,595,458)
24	To Normalize Certain Outside Professional Services	1.11	$ (267)
25	To Normalize Demand Side Management Expenses	1.12	$ (131,314)
26	Subtotal	Lines 14 - 25	$ (54,983,137)
27			
28	Adjusted Cost of Service	Line 11 + Line 26	$ 423,330,643
29			
30	Adjusted Operating Margins	Line 9 - Line 28	$ (67,776,020)

BIG RIVERS ELECTRIC CORPORATION
Calculation of Revenue Requirement
Based on Fully Forecasted Test Period
For the 12 Months Ended August 31, 2014

Line	Description	Ref Sched		Amount
31				
32	**Non-Operating Items**			
33	Interest Income	Exh Siewert-3	$	1,974,858
34	Other Non-Operating Income	Exh Siewert-3	$	-
35	Other Capital Credits / Patronage Dividends	Exh Siewert-3	$	2,706,448
36				
37	Total Non-Operating Items	Lines 33-35	$	4,681,305
38				
39	**Calculation of Revenue Deficiency**			
40				
41	Adjusted Net Margin (Deficit)	Line 30 + 37	$	(63,094,715)
42				
43	Contract TIER			1.24
44				
45	Interest on Long-Term Debt	Exh Siewert-3	$	46,983,291
46				
47	Interest Income on Transition Reserve	Big Rivers Finan Model	$	105,415
48				
49	Adjusted Net Margin(Deficit) before Contract TIER	Line 41 - 47	$	(63,200,130)
50				
51	Margins Required for Contract TIER	Line 45*(Line 43-1) + Line 47	$	11,381,405
52				
53	**Revenue Deficiency for 1.24 Contract TIER**	Line 41 - 51	**$**	**(74,476,120)**

BIG RIVERS ELECTRIC CORPORATION
Based on the Fully Forecast Test Period
For the 12 Months Ended August 31, 2014

Fuel Adjustment Clause Revenues and Expenses

Line #	Year (1)	Month (2)	Revenue (3)	Expense (4)
1	2013	Sep	$ 2,422,721	$ 2,422,721
2	2013	Oct	$ 2,246,696	$ 2,246,696
3	2013	Nov	$ 2,376,004	$ 2,376,004
4	2013	Dec	$ 2,768,043	$ 2,768,043
5	2014	Jan	$ 2,946,525	$ 2,946,525
6	2014	Feb	$ 2,679,749	$ 2,679,749
7	2014	Mar	$ 2,816,214	$ 2,816,214
8	2014	Apr	$ 2,600,912	$ 2,600,912
9	2014	May	$ 2,803,722	$ 2,803,722
10	2014	Jun	$ 3,139,817	$ 3,139,817
11	2014	Jul	$ 3,386,751	$ 3,386,751
12	2014	Aug	$ 3,351,844	$ 3,351,844
13		TOTAL	$ 33,538,999	$ 33,538,999
14				
15	Test Year Cost		$ 33,538,999	$ 33,538,999
16				
17	Pro Forma Year Cost		$ -	$ -
18				
19	Adjustment		$ (33,538,999)	$ (33,538,999)

BIG RIVERS ELECTRIC CORPORATION
Based on the Fully Forecast Test Period
For the 12 Months Ended August 31, 2014

Environmental Surcharge Revenues and Expenses

Line #	Year (1)	Month (2)	Revenue (3)	Expense (4)
1	2013	Sep	$ 1,821,254	$ 1,821,254
2	2013	Oct	$ 1,689,708	$ 1,689,708
3	2013	Nov	$ 1,606,895	$ 1,606,895
4	2013	Dec	$ 1,748,478	$ 1,748,478
5	2014	Jan	$ 1,901,937	$ 1,901,937
6	2014	Feb	$ 1,704,943	$ 1,704,943
7	2014	Mar	$ 1,633,749	$ 1,633,749
8	2014	Apr	$ 1,586,737	$ 1,586,737
9	2014	May	$ 1,655,556	$ 1,655,556
10	2014	Jun	$ 1,821,469	$ 1,821,469
11	2014	Jul	$ 1,911,429	$ 1,911,429
12	2014	Aug	$ 2,239,000	$ 2,239,000
13		TOTAL	$ 21,321,155	$ 21,321,155
14				
15	Test Year Cost		$ 21,321,155	$ 21,321,155
16				
17	Pro Forma Year Cost		$ -	$ -
18				
19	Adjustment		$ (21,321,155)	$ (21,321,155)

BIG RIVERS ELECTRIC CORPORATION
Based on the Fully Forecast Test Period
For the 12 Months Ended August 31, 2014

Non-FAC PPA Revenues and Expenses

Line #	Year (1)	Month (2)	Revenue (3)	Expense (4)
1	2013	Sep	$ (181,408)	$ (181,408)
2	2013	Oct	$ (169,392)	$ (169,392)
3	2013	Nov	$ (182,095)	$ (182,095)
4	2013	Dec	$ (249,592)	$ (249,592)
5	2014	Jan	$ (248,097)	$ (248,097)
6	2014	Feb	$ (184,810)	$ (184,810)
7	2014	Mar	$ (194,724)	$ (194,724)
8	2014	Apr	$ (149,069)	$ (149,069)
9	2014	May	$ (173,623)	$ (173,623)
10	2014	Jun	$ (209,915)	$ (209,915)
11	2014	Jul	$ (245,972)	$ (245,972)
12	2014	Aug	$ (237,736)	$ (237,736)
13		TOTAL	$ (2,426,432)	$ (2,426,432)
14				
15	Test Year Cost		$ (2,426,432)	$ (2,426,432)
16				
17	Pro Forma Year Cost		$ -	$ -
18				
19	Adjustment		$ 2,426,432	$ 2,426,432

Reference Schedule: 1.04

BIG RIVERS ELECTRIC CORPORATION
Based on the Fully Forecast Test Period
For the 12 Months Ended August 31, 2014

Promotional Advertising

Line #	Year (1)	Month (2)		Amount (3)
1	2013	Sep	$	4,500
2	2013	Oct	$	4,000
3	2013	Nov	$	4,500
4	2013	Dec	$	5,290
5	2014	Jan	$	5,500
6	2014	Feb	$	5,000
7	2014	Mar	$	5,500
8	2014	Apr	$	4,966
9	2014	May	$	4,000
10	2014	Jun	$	4,500
11	2014	Jul	$	4,000
12	2014	Aug	$	4,000
13		TOTAL	$	55,756
14				
15	Test Year Cost		$	55,756
16				
17	Pro Forma Year Cost		$	-
18				
19	Adjustment		$	(55,756)

BIG RIVERS ELECTRIC CORPORATION
Based on the Fully Forecast Test Period
For the 12 Months Ended August 31, 2014

Lobbying Expenses

Line #	Year (1)	Month (2)	Amount (3)
1	2013	Sep	$ 1,820
2	2013	Oct	$ 1,120
3	2013	Nov	$ 1,120
4	2013	Dec	$ 1,820
5	2014	Jan	$ 1,520
6	2014	Feb	$ 1,520
7	2014	Mar	$ 2,270
8	2014	Apr	$ 1,486
9	2014	May	$ 54,137
10	2014	Jun	$ 1,870
11	2014	Jul	$ 1,120
12	2014	Aug	$ 1,120
13		TOTAL	$ 70,923
14			
15	Test Year Cost		$ 70,923
16			
17	Pro Forma Year Cost		$ -
18			
19	Adjustment		$ (70,923)

BIG RIVERS ELECTRIC CORPORATION
Based on the Fully Forecast Test Period
For the 12 Months Ended August 31, 2014

Economic Development Expenses

Line #	Year (1)	Month (2)	Amount (3)
1	2013	Sep	$ 140,357
2	2013	Oct	$ -
3	2013	Nov	$ -
4	2013	Dec	$ -
5	2014	Jan	$ -
6	2014	Feb	$ -
7	2014	Mar	$ -
8	2014	Apr	$ -
9	2014	May	$ -
10	2014	Jun	$ -
11	2014	Jul	$ -
12	2014	Aug	$ -
13		TOTAL	$ 140,357
14			
15	Test Year Cost		$ 140,357
16			
17	Pro Forma Year Cost		$ -
18			
19	Adjustment		$ (140,357)

Reference Schedule: 1.07

BIG RIVERS ELECTRIC CORPORATION
Based on the Fully Forecast Test Period
For the 12 Months Ended August 31, 2014

Donations Expenses

Line #	Year (1)	Month (2)	Amount (3)
1	2013	Sep	$ 1,000
2	2013	Oct	$ 1,000
3	2013	Nov	$ 1,000
4	2013	Dec	$ 4,643
5	2014	Jan	$ 26,050
6	2014	Feb	$ 2,060
7	2014	Mar	$ 2,575
8	2014	Apr	$ 21,000
9	2014	May	$ 1,000
10	2014	Jun	$ 1,000
11	2014	Jul	$ 1,000
12	2014	Aug	$ 1,000
13		TOTAL	$ 63,328
14			
15	Test Year Cost		$ 63,328
16			
17	Pro Forma Year Cost		$ -
18			
19	Adjustment		$ (63,328)

BIG RIVERS ELECTRIC CORPORATION
Based on the Fully Forecast Test Period
For the 12 Months Ended August 31, 2014

Touchstone Energy Dues Expenses

Line #	Year (1)	Month (2)	Amount (3)
1	2013	Sep	$ -
2	2013	Oct	$ -
3	2013	Nov	$ -
4	2013	Dec	$ -
5	2014	Jan	$ -
6	2014	Feb	$ -
7	2014	Mar	$ 132,766
8	2014	Apr	$ -
9	2014	May	$ -
10	2014	Jun	$ -
11	2014	Jul	$ -
12	2014	Aug	$ -
13		TOTAL	$ 132,766
14			
15	Test Year Cost		$ 132,766
16			
17	Pro Forma Year Cost		$ -
18			
19	Adjustment		$ (132,766)

BIG RIVERS ELECTRIC CORPORATION
Based on the Fully Forecast Test Period
For the 12 Months Ended August 31, 2014

Amortization of Rate Case Expenses for Case No. 2011-00036

Line #	Year (1)	Amount (2)
1	Test Year Cost	$ -
2		
3	Pro Forma Year Cost	$ 640,753
4		
5	Adjustment	$ 640,753

BIG RIVERS ELECTRIC CORPORATION
Based on the Fully Forecast Test Period
For the 12 Months Ended August 31, 2014

Non-Recurring Labor Related to Wilson Layup

Line #	Year (1)	Month (2)		Plant (3)		!T (4)		Safety (5)		Budget (6)		Supply Chain (7)		TOTAL (8)
1	2013	Sep	$	907,956	$	11,216	$	9,989	$	64,604	$	121,516	$	1,115,279
2	2013	Oct	$	1,078,564	$	13,277	$	11,825	$	76,479	$	143,853	$	1,323,998
3	2013	Nov	$	891,785	$	11,051	$	9,842	$	63,654	$	119,729	$	1,096,059
13		TOTAL	$	2,878,304	$	35,543	$	31,655	$	204,736	$	385,098	$	3,535,337
14														
15	Test Year Cost		$	2,878,304	$	35,543	$	31,655	$	204,736	$	385,098	$	3,535,337
16														
17	Headcount - Budget			102		1		1		7		16		127
18	Headcount - Pro Forma			16		0		0		6		13		35
19	Ratio			0.157		-		-		0.857		0.813		n/a
20														
21	Pro Forma Year Cost		$	451,499	$	-	$	-	$	175,488	$	312,892	$	939,879
22														
23	Adjustment		$	(2,426,806)	$	(35,543)	$	(31,655)	$	(29,248)	$	(72,206)	$	(2,595,458)

Reference Schedule: 1.11

BIG RIVERS ELECTRIC CORPORATION
Based on the Fully Forecast Test Period
For the 12 Months Ended August 31, 2014

Normalization of Certain Outside Professional Services

Line #	Year (1)	Month (2)	Integrated Resource Plan (3)	Load Forecast (4)	Transient Stability Study (5)	TOTAL (6)
1	2013	Sep	$ 35,250	$ -	$ -	$ 35,250
2	2013	Oct	$ 35,250	$ -	$ -	$ 35,250
3	2013	Nov	$ -	$ -	$ -	$ -
4	2013	Dec	$ -	$ -	$ -	$ -
5	2014	Jan	$ 20,600	$ -	$ -	$ 20,600
6	2014	Feb	$ 20,000	$ -	$ -	$ 20,000
7	2014	Mar	$ 20,000	$ -	$ 30,000	$ 50,000
8	2014	Apr	$ 20,000	$ -	$ -	$ 20,000
9	2014	May	$ -	$ -	$ -	$ -
10	2014	Jun	$ -	$ -	$ -	$ -
11	2014	Jul	$ -	$ -	$ -	$ -
12	2014	Aug	$ -	$ -	$ -	$ -
13		TOTAL	$ 151,100	$ -	$ 30,000	$ 181,100
14						
15	Periodicity (Years)		3	2	2	n/a
16						
17	Test Year Cost		$ 445,000	$ 65,000	$ 30,000	$ 540,000
18						
19	Normalized Annual Cost		$ 148,333	$ 32,500	$ -	$ 180,833
20						
21	Adjustment		$ (2,767)	$ 32,500	$ (30,000)	$ (267)

BIG RIVERS ELECTRIC CORPORATION
Based on the Fully Forecast Test Period
For the 12 Months Ended August 31, 2014

Demand Side Management Expenses

Line #	Year (1)	Month (2)	Amount (3)
1	2013	Sep	$ 78,144
2	2013	Oct	$ 90,874
3	2013	Nov	$ 72,839
4	2013	Dec	$ 251,014
5	2014	Jan	$ 53,347
6	2014	Feb	$ 44,124
7	2014	Mar	$ 52,868
8	2014	Apr	$ 44,124
9	2014	May	$ 44,124
10	2014	Jun	$ 311,608
11	2014	Jul	$ 44,124
12	2014	Aug	$ 44,124
13		TOTAL	$ 1,131,314
14			
15	Test Year Cost		$ 1,131,314
16			
17	Pro Forma Year Cost		$ 1,000,000
18			
19	Adjustment		$ (131,314)

Exhibit Wolfram-3
Cost of Service Study: Functional Assignment and Classification

Exhibit Wolfram-3

Cost of Service Study:

Functional Assignment and Classification

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
August 31, 2014

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Transmission Demand
Plant in Service						
Intangible Plant	INTPLT	PT&D	$ 66,895	58,452	-	8,443
Production Plant	PPROD	F001	$ 1,769,875,009	1,769,875,009	-	-
Transmission Plant	PTRAN	F002	$ 255,644,032	-	-	255,644,032
Distribution Plant	PDIST	F003	$ -	-	-	-
Total Production & Transmission Plant	PT&D		2,025,519,041	1,769,875,009	-	255,644,032
General Plant	PGP	PT&D	$ 36,225,459	31,653,385	-	4,572,074
Total Plant in Service	TPIS		$ 2,061,811,395	$ 1,801,586,846	$ -	$ 260,224,549
Construction Work in Progress (CWIP)						
CWIP Production	CWIP1	PPROD	$ 59,715,449	59,715,449	-	-
CWIP Transmission	CWIP2	PTRAN	$ 14,556,975	-	-	14,556,975
CWIP Distribution Plant	CWIP3	PDIST	$ -	-	-	-
CWIP General Plant	CWIP4	PT&D	$ 617,305	539,394	-	77,911
Total Construction Work in Progress	TCWIP		$ 74,889,729	$ 60,254,843	$ -	$ 14,634,886
Total Utility Plant			$ 2,136,701,124	$ 1,861,841,689	$ -	$ 274,859,435

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
August 31, 2014

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Transmission Demand
Rate Base						
Total Utility Plant	TUP		$ 2,136,701,124	$ 1,861,841,689	$ -	$ 274,859,435
Less: Acummulated Provision for Depreciation						
Production	ADEPREPA	PPROD	$ 874,868,570	874,868,570	-	-
Transmission	ADEPRTP	PTRAN	$ 122,541,670	-	-	122,541,670
Distribution	ADEPRD11	PDIST	$ -	-	-	-
General & Common Plant	ADEPRD12	PT&D	$ 9,260,903	8,092,069	-	1,168,834
Intangible, Misc, and Other Plant	ADEPRGP	PT&D	$ -	-	-	-
Retirement Work In Progress	ADEPRRT	PT&D	$ -	-	-	-
Total Accumulated Depreciation	TADEPR		$ 1,006,671,143	$ 882,960,639	$ -	$ 123,710,504
Net Utility Plant	NTPLANT		$ 1,130,029,981	$ 978,881,050	$ -	$ 151,148,931
Working Capital						
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP	$ 47,326,498	11,337,372	33,577,574	2,411,552
Materials and Supplies	M&S	TPIS	$ 27,026,950	23,615,835	-	3,411,115
Fuel Stock	PREPAY	TPIS	$ 33,315,891	29,111,039	-	4,204,852
Total Working Capital	TWC		$ 107,669,339	$ 64,064,246	$ 33,577,574	$ 10,027,519
Net Rate Base	RB		$ 1,237,699,320	$ 1,042,945,296	$ 33,577,574	$ 161,176,450

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
August 31, 2014

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Transmission Demand
Operation and Maintenance Expenses						
Steam Power Generation Operation Expenses						
500 OPERATION SUPERVISION & ENGINEERING	OM500	PROFIX	[redacted]			-
501 FUEL	OM501	Energy				-
502 STEAM EXPENSES	OM502	PROFIX				-
505 ELECTRIC EXPENSES	OM505	PROFIX				-
506 MISC. STEAM POWER EXPENSES	OM506	PROFIX				-
507 RENTS	OM507	PROFIX				-
509 ALLOWANCES	OM509	Energy				-
Total Steam Power Operation Expenses						$ -
Steam Power Generation Maintenance Expenses						
510 MAINTENANCE SUPERVISION & ENGINEERING	OM510	Energy				-
511 MAINTENANCE OF STRUCTURES	OM511	PROFIX				-
512 MAINTENANCE OF BOILER PLANT	OM512	Energy				-
513 MAINTENANCE OF ELECTRIC PLANT	OM513	Energy				-
514 MAINTENANCE OF MISC STEAM PLANT	OM514	PROFIX				-
Total Steam Power Generation Maintenance Expense						$ -
Total Steam Power Generation Expense						$ -

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
August 31, 2014

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Transmission Demand
Operation and Maintenance Expenses (Continued)						
Other Power Generation Operation Expense						
546 OPERATION SUPERVISION & ENGINEERING	OM546	PROFIX	[redacted]	[redacted]	[redacted]	-
547 FUEL	OM547	Energy	[redacted]	[redacted]	[redacted]	-
548 GENERATION EXPENSE	OM548	PROFIX	[redacted]	[redacted]	[redacted]	-
549 MISC OTHER POWER GENERATION	OM549	PROFIX	[redacted]	[redacted]	[redacted]	-
550 RENTS	OM550	PROFIX	[redacted]	[redacted]	[redacted]	-
Total Other Power Generation Expenses			[redacted]	[redacted]	[redacted]	$ -
Other Power Generation Maintenance Expense						
551 MAINTENANCE SUPERVISION & ENGINEERING	OM551	PROFIX	[redacted]	[redacted]	[redacted]	-
552 MAINTENANCE OF STRUCTURES	OM552	PROFIX	[redacted]	[redacted]	[redacted]	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	OM553	PROFIX	[redacted]	[redacted]	[redacted]	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	OM554	PROFIX	[redacted]	[redacted]	[redacted]	-
Total Other Power Generation Maintenance Expense			[redacted]	[redacted]	[redacted]	$ -
Total Other Power Generation Expense			[redacted]	[redacted]	[redacted]	$ -
Total Station Expense			[redacted]	[redacted]	[redacted]	$ -

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
August 31, 2014

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Transmission Demand
Operation and Maintenance Expenses (Continued)						
Other Power Supply Expenses						
555 PURCHASED POWER Energy	OM555	OMPP	[redacted]			-
555 PURCHASED POWER Demand	OMD555	OMPPD	[redacted]			-
555 PURCHASED POWER BREC Share of HMP&L Station Two	OMH555	OMPPH	[redacted]			-
555 PURCHASED POWER OPTIONS	OMO555	OMPP	[redacted]			-
555 BROKERAGE FEES	OMB555	OMPP	[redacted]			-
555 MISO TRANSMISSION EXPENSES	OMM555	OMPP	[redacted]			-
556 SYSTEM CONTROL AND LOAD DISPATCH	OM556	PROFIX	[redacted]			-
557 OTHER EXPENSES	OM557	PROFIX	[redacted]			-
558 DUPLICATE CHARGES	OM558	Energy	[redacted]			-
Total Other Power Supply Expenses	TPP		[redacted]			$ -
Total Electric Power Generation Expenses			[redacted]			$ -
Transmission Expenses						
560 OPERATION SUPERVISION AND ENG	OM560	LBTRAN	$ 956,020	-	-	956,020
561 LOAD DISPATCHING	OM561	LBTRAN	$ 2,438,223	-	-	2,438,223
562 STATION EXPENSES	OM562	PTRAN	$ 720,812	-	-	720,812
563 OVERHEAD LINE EXPENSES	OM563	PTRAN	$ 1,236,070	-	-	1,236,070
565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	PTRAN	$ 2,448,000	-	-	2,448,000
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	$ 613,921	-	-	613,921
567 RENTS	OM567	PTRAN	$ 58,669	-	-	58,669
568 MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN	$ 540,092	-	-	540,092
569 STRUCTURES	OM569	PTRAN	$ (83,165)	-	-	(83,165)
570 MAINT OF STATION EQUIPMENT	OM570	PTRAN	$ 1,720,315	-	-	1,720,315
571 MAINT OF OVERHEAD LINES	OM571	PTRAN	$ 2,310,747	-	-	2,310,747
572 UNDERGROUND LINES	OM572	PTRAN	$ -	-	-	-
573 MISC PLANT	OM573	PTRAN	$ 756,058	-	-	756,058
573 MARKET FACILITATION MONITORING MISO	OM575	PTRAN	$ 1,343,829	-	-	1,343,829
Total Transmission Expenses			$ 15,059,590	$ -	$ -	$ 15,059,590

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended August 31, 2014

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Transmission Demand
<u>Operation and Maintenance Expenses (Continued)</u>						
Total Distribution Operation and Maintenance Expenses			-	-	-	-
Transmission and Distribution Expenses			15,059,590	-	-	15,059,590
Production, Transmission and Distribution Expenses	OMSUB		[redacted]			$ 15,059,590
Customer Accounts Expense						
901 SUPERVISION/CUSTOMER ACCTS	OM901	F025	$ -	-	-	-
902 METER READING EXPENSES	OM902	F025	$ -	-	-	-
903 RECORDS AND COLLECTION	OM903	F025	$ -	-	-	-
904 UNCOLLECTIBLE ACCOUNTS	OM904	F025	$ -	-	-	-
905 MISC CUST ACCOUNTS	OM903	F025	$ -	-	-	-
Total Customer Accounts Expense	OMCA		$ -	$ -	$ -	$ -
Customer Service Expense						
907 SUPERVISION	OM907	TUP	$ -	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	OM908	TUP	$ 1,341,868	1,169,254	-	172,614
908 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	TUP	$ -	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	OM909	TUP	$ 32,467	28,290	-	4,176
909 INFORM AND INSTRUC -LOAD MGMT	OM909x	TUP	$ -	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	OM910	TUP	$ -	-	-	-
911 DEMONSTRATION AND SELLING EXP	OM911	TUP	$ -	-	-	-
912 DEMONSTRATION AND SELLING EXP	OM912	TUP	$ -	-	-	-
913 ADVERTISING EXPENSES	OM913	TUP	$ 139,067	121,178	-	17,889
915 MDSE-JOBBING-CONTRACT	OM915	TUP	$ -	-	-	-
916 MISC SALES EXPENSE	OM916	TUP	$ -	-	-	-
Total Customer Service Expense	OMCS		$ 1,513,401	$ 1,318,722	$ -	$ 194,680
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2		360,561,181	76,946,958	268,359,952	15,254,270

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
August 31, 2014

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Transmission Demand
Operation and Maintenance Expenses (Continued)						
Administrative and General Expense						
920 ADMIN. & GEN. SALARIES-	OM920	LBSUB9	$ 13,800,793	6,604,776	5,242,723	1,953,294
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB9	$ 8,709,572	4,168,223	3,308,641	1,232,709
922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB9	$ -	-	-	-
923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB9	$ 3,651,543	1,747,553	1,387,168	516,821
924 PROPERTY INSURANCE	OM924	TUP	$ -	-	-	-
925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB9	$ -	-	-	-
926 EMPLOYEE BENEFITS	OM926	LBSUB9	$ 401,841	192,313	152,654	56,875
927 FRANCHISE REQUIREMENTS	OM927	TUP	$ -	-	-	-
928 REGULATORY COMMISSION FEES	OM928	TUP	$ -	-	-	-
929 DUPLICATE CHARGES-CR	OM929	LBSUB9	$ -	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB9	$ 1,772,549	848,306	673,366	250,878
931 RENTS AND LEASES	OM931	PGP	$ 1,933	1,689	-	244
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP	$ 216,483	189,160	-	27,323
Total Administrative and General Expense	OMAG		$ 28,554,714	$ 13,752,020	$ 10,764,552	$ 4,038,143
Total Operation and Maintenance Expenses	TOM		[redacted]			$ 19,292,413
Operation and Maintenance Expenses Less Purchased Power	OMLPP		[redacted]			$ 19,292,413

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
August 31, 2014

Description	Name	Functional Vector		Total System		Production Demand		Production Energy		Transmission Demand
Labor Expenses										
Steam Power Generation Operation Expenses										
500 OPERATION SUPERVISION & ENGINEERING	LB500	PROFIX	$	4,280,950		4,280,950		-		-
501 FUEL	LB501	Energy	$	2,902,882		-		2,902,882		-
502 STEAM EXPENSES	LB502	PROFIX	$	5,491,704		5,491,704		-		-
505 ELECTRIC EXPENSES	LB505	PROFIX	$	5,535,107		5,535,107		-		-
506 MISC. STEAM POWER EXPENSES	LB506	PROFIX	$	1,356,089		1,356,089		-		-
507 RENTS	LB507	PROFIX	$	-		-		-		-
509 ALLOWANCES	LB509	Energy	$	-		-		-		-
Total Steam Power Operation Expenses	LBSUB1		$	19,566,731	$	16,663,849	$	2,902,882	$	-
Steam Power Generation Maintenance Expenses										
510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	Energy	$	4,294,352		-		4,294,352		-
511 MAINTENANCE OF STRUCTURES	LB511	PROFIX	$	834,792		834,792		-		-
512 MAINTENANCE OF BOILER PLANT	LB512	Energy	$	6,591,131		-		6,591,131		-
513 MAINTENANCE OF ELECTRIC PLANT	LB513	Energy	$	1,263,465		-		1,263,465		-
514 MAINTENANCE OF MISC STEAM PLANT	LB514	PROFIX	$	1,294,907		1,294,907		-		-
Total Steam Power Generation Maintenance Expense	LBSUB2		$	14,278,646	$	2,129,699	$	12,148,947	$	-
Total Steam Power Generation Expense			$	33,845,377	$	18,793,548	$	15,051,830	$	-

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
August 31, 2014

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Transmission Demand
Labor Expenses (Continued)						
Other Power Generation Operation Expense						
546 OPERATION SUPERVISION & ENGINEERING	LB546	PROFIX	$ -	-	-	-
547 FUEL	LB547	Energy	$ -	-	-	-
548 GENERATION EXPENSE	LB548	PROFIX	$ -	-	-	-
549 MISC OTHER POWER GENERATION	LB549	PROFIX	$ -	-	-	-
550 RENTS	LB550	PROFIX	$ -			
Total Other Power Generation Expenses	LBSUB7		$ -	$ -	$ -	$ -
Other Power Generation Maintenance Expense						
551 MAINTENANCE SUPERVISION & ENGINEERING	LB551	PROFIX	$ -	-	-	-
552 MAINTENANCE OF STRUCTURES	LB552	PROFIX	$ -	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	LB553	PROFIX	$ -	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX	$ -			
Total Other Power Generation Maintenance Expense	LBSUB8		$ -	$ -	$ -	$ -
Total Other Power Generation Expense			$ -	$ -	$ -	$ -
Total Production Expense	LPREX		$ 33,845,377	$ 18,793,548	$ 15,051,830	$ -

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
August 31, 2014

Description	Name	Functional Vector		Total System		Production Demand		Production Energy		Transmission Demand
Labor Expenses (Continued)										
Purchased Power										
555 PURCHASED POWER Energy	LB555	OMPP	$	-		-		-		-
555 PURCHASED POWER Demand	LBD555	OMPPD	$	-		-		-		-
555 PURCHASED POWER OPTIONS	LBO555	OMPP	$	-		-		-		-
555 BROKERAGE FEES	LBB555	OMPP	$	-		-		-		-
555 MISO TRANSMISSION EXPENSES	LBM555	OMPP	$	-		-		-		-
556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX	$	-		-		-		-
557 OTHER EXPENSES	LB557	PROFIX	$	-		-		-		-
558 DUPLICATE CHARGES	LB558	Energy	$	-		-		-		-
Total Purchased Power Labor	LBPP		$	-	$	-	$	-	$	-
Transmission Labor Expenses										
560 OPERATION SUPERVISION AND ENG	LB560	PTRAN	$	777,780		-		-		777,780
561 LOAD DISPATCHING	LB561	PTRAN	$	1,115,069		-		-		1,115,069
562 STATION EXPENSES	LB562	PTRAN	$	200,779		-		-		200,779
563 OVERHEAD LINE EXPENSES	LB563	PTRAN	$	72,556		-		-		72,556
565 TRANSMISSION OF ELECTRICITY BY OTHERS	LB565	PTRAN	$	-		-		-		-
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN	$	410,985		-		-		410,985
567 RENTS	LB567	PTRAN	$	-		-		-		-
568 MAINTENACE SUPERVISION AND ENG	LB568	PTRAN	$	260,558		-		-		260,558
569 MAINTENACE OF STRUCTURES	LB569	PTRAN	$	-		-		-		-
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN	$	1,372,631		-		-		1,372,631
571 MAINT OF OVERHEAD LINES	LB571	PTRAN	$	1,118,685		-		-		1,118,685
573 MAINT OF MISC. TRANSMISSION PLANT	LB573	PTRAN	$	253,946		-		-		253,946
Total Transmission Labor Expenses	LBTRAN		$	5,582,989	$	-	$	-	$	5,582,989

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
August 31, 2014

Description	Name	Functional Vector		Total System		Production Demand		Production Energy		Transmission Demand
Labor Expenses (Continued)										
Total Distribution Operation and Maintenance Labor Expenses		PDIST		-		-		-		-
Transmission and Distribution Labor Expenses				5,582,989		-		-		5,582,989
Production, Transmission and Distribution Labor Expenses	LBSUB		$	39,428,366	$	18,793,548	$	15,051,830	$	5,582,989
Customer Accounts Expense										
901 SUPERVISION/CUSTOMER ACCTS	LB901	F025	$	-		-		-		-
902 METER READING EXPENSES	LB902	F025	$	-		-		-		-
903 RECORDS AND COLLECTION	LB903	F025	$	-		-		-		-
904 UNCOLLECTIBLE ACCOUNTS	LB904	F025	$	-		-		-		-
905 MISC CUST ACCOUNTS	LB903	F025	$	-		-		-		-
Total Customer Accounts Labor Expense	LBCA		$	-	$	-	$	-	$	-
Customer Service Expense										
907 SUPERVISION	LB907	TUP	$	-		-		-		-
908 CUSTOMER ASSISTANCE EXPENSES	LB908	TUP	$	193,640		168,731		-		24,909
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	TUP	$	-		-		-		-
909 INFORMATIONAL AND INSTRUCTIONA	LB909	TUP	$	-		-		-		-
909 INFORM AND INSTRUC -LOAD MGMT	LB909x	TUP	$	-		-		-		-
910 MISCELLANEOUS CUSTOMER SERVICE	LB910	TUP	$	-		-		-		-
911 DEMONSTRATION AND SELLING EXP	LB911	TUP	$	-		-		-		-
912 DEMONSTRATION AND SELLING EXP	LB912	TUP	$	-		-		-		-
913 WATER HEATER - HEAT PUMP PROGRAM	LB913	TUP	$	-		-		-		-
915 MDSE-JOBBING-CONTRACT	LB915	TUP	$	-		-		-		-
916 MISC SALES EXPENSE	LB916	TUP	$	-		-		-		-
Total Customer Service Labor Expense	LBCS		$	193,640	$	168,731	$	-	$	24,909
Sub-Total Labor Exp	LBSUB9			39,622,006		18,962,278		15,051,830		5,607,898

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
August 31, 2014

Description	Name	Functional Vector		Total System		Production Demand		Production Energy		Transmission Demand
<u>Labor Expenses (Continued)</u>										
Administrative and General Expense										
920 ADMIN. & GEN. SALARIES-	LB920	LBSUB9	$	13,800,793		6,604,776		5,242,723		1,953,294
921 OFFICE SUPPLIES AND EXPENSES	LB921	LBSUB9	$	-		-		-		-
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB9	$	-		-		-		-
923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB9	$	-		-		-		-
924 PROPERTY INSURANCE	LB924	TUP	$	-		-		-		-
925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB9	$	-		-		-		-
926 EMPLOYEE BENEFITS	LB926	LBSUB9	$	304,550		145,751		115,694		43,104
928 REGULATORY COMMISSION FEES	LB928	TUP	$	-		-		-		-
929 DUPLICATE CHARGES-CR	LB929	LBSUB9	$	-		-		-		-
930 MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB9	$	-		-		-		-
931 RENTS AND LEASES	LB931	PGP	$	-		-		-		-
935 MAINTENANCE OF GENERAL PLANT	LB935	PGP	$	108,834		95,098		-		13,736
Total Administrative and General Expense	LBAG		$	14,214,177	$	6,845,625	$	5,358,417	$	2,010,135
Total Operation and Maintenance Expenses	TLB		$	53,836,183	$	25,807,904	$	20,410,246	$	7,618,033
Operation and Maintenance Expenses Less Purchase Power	LBLPP		$	53,836,183	$	25,807,904	$	20,410,246	$	7,618,033

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended August 31, 2014

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Transmission Demand
Other Expenses						
Depreciation Expenses						
Production	DEPRDP2	PPROD	$ 35,686,949	35,686,949	-	-
Transmission	DEPRDP3	PTRAN	$ 5,046,463	-	-	5,046,463
Transmission	DEPRDP4	PTRAN	$ -	-	-	-
Distribution	DEPRDP5	PDIST	$ -	-	-	-
General & Common Plant	DEPRDP6	PGP	$ 3,369,604	2,944,321	-	425,283
Other Plant	DEPROTH	TPIS	$ -	-	-	-
Total Depreciation Expense	TDEPR		$ 44,103,016	38,631,270	-	5,471,746
Property Taxes & Other	PTAX	TUP	$ 885	771	-	114
Amortization of Investment Tax Credit	OTAX	TUP	$ -	-	-	-
Other Interest Expenses	OT	TUP	$ -	-	-	-
Interest on Long Term Debt	INTLTD	TUP	$ 46,983,291	40,939,488	-	6,043,803
Interest Charged to Construction - CR		TUP	$ (2,480,401)	(2,161,329)	-	(319,072)
Other Deductions	DEDUCT	TUP	$ 591,094	515,057	-	76,037
Total Other Expenses	TOE		$ 89,197,886	$ 77,925,258	$ -	$ 11,272,628
Total Cost of Service (O&M + Other Expenses)			[redacted]			$ 30,565,041

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
August 31, 2014

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Transmission Demand
Functional Vectors						
Production Plant	F001		1.000000	1.000000	0.000000	0.000000
Transmission Plant	F002		1.000000	0.000000	0.000000	1.000000
Distribution Plant	F003		1.000000	0.000000	0.000000	1.000000
Production Plant	F017		1.000000	0.000000	1.000000	0.000000
Production Variable Cost	PROVAR		1.000000	0.000000	1.000000	0.000000
Production Fixed Cost	PROFIX		1.000000	1.000000	0.000000	0.000000
Distribution Operation Labor	F023		-	-	-	-
Distribution Maintenance Labor	F024		-	-	-	-
Customer Accounts Expense	F025		1.000000	0.000000	0.000000	1.000000
Customer Service Expense	F026		1.000000	0.000000	0.000000	1.000000
Purchased Power Energy	OMPP		1.000000	0.000000	1.000000	0.000000
Purchased Power Demand	OMPPD		[redacted]			0.000000
Purchased Power BREC Share of HMP&L Station Two	OMPPH		[redacted]			0.000000
				-	-	0.000000
Production Energy	Energy		1.000000	0.000000	1.000000	0.000000
Internally Generated Functional Vectors						
Total Prod, Trans, and Dist Plant		PT&D	1.000000	0.873788	-	0.126212
Total Transmission Plant		PTRAN	1.000000	-	-	1.000000
Operation and Maintenance Expenses Less Purchased Power		OMLPP	1.000000	0.239557	0.709488	0.050956
Total Plant in Service		TPIS	1.000000	0.873788	-	0.126212
Total Operation and Maintenance Expenses (Labor)		TLB	1.000000	0.479378	0.379118	0.141504
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service		OMSUB2	1.000000	0.213409	0.744284	0.042307
Total Steam Power Operation Expenses (Labor)		LBSUB1	1.000000	0.851642	0.148358	-
Total Steam Power Generation Maintenance Expense (Labor)		LBSUB2	1.000000	0.149153	0.850847	-
Total Transmission Labor Expenses		LBTRAN	1.000000	-	-	1.0000000
Sub-Total Labor Exp		LBSUB7	1.000000	0.478579	0.379886	0.141535
Total General Plant		PGP	1.000000	0.873788	-	0.126212
Total Production Plant		PPROD	1.000000	1.000000	-	-
Total Intangible Plant		INTPLT	1.000000	0.873788	-	0.126212

Exhibit Wolfram-4
Cost of Service Study: Allocation to Rate Classes

Exhibit Wolfram-4

Cost of Service Study:

Allocation to Rate Classes

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
August 31, 2014

Description	Ref	Name	Allocation Vector		Rurals		Large Industrials		Smelter		Total System
Plant in Service											
Power Production Plant											
Production Demand	TPIS	PLPDMD	12CP	$	859,802,270	$	228,392,044	$	713,392,532	$	1,801,586,846
Production Energy	TPIS	PLPENG	PENG	$	-	$	-	$	-	$	-
Production - Steam Direct	TPIS	PLPSTM	STMD	$	-	$	-	$	-	$	-
Total Power Production Plant		PLPT		$	859,802,270	$	228,392,044	$	713,392,532	$	1,801,586,846
Transmission Plant	TPIS	PLTRN	12CP	$	124,191,436	$	32,989,371	$	103,043,742	$	260,224,549
Distribution Substation	TPIS	PLDST	SUBA	$	-	$	-	$	-	$	-
Distribution Other	TPIS	PLDMC	Cust05	$	-	$	-	$	-	$	-
Total		PLT		$	983,993,707	$	261,381,415	$	816,436,274	$	2,061,811,395

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
August 31, 2014

Description	Ref	Name	Allocation Vector	Rurals	Large Industrials	Smelter	Total System
Net Utility Plant							
Power Production Plant							
Production Demand	NTPLANT	NTPDMD	12CP	$ 467,168,236	$ 124,095,402	$ 387,617,412	$ 978,881,050
Production Energy	NTPLANT	NTPENG	PENG	$ -	$ -	$ -	$ -
Production - Steam Direct	NTPLANT	NTPSTM	STMD	$ -	$ -	$ -	$ -
Total Power Production Plant		NTPT		$ 467,168,236	$ 124,095,402	$ 387,617,412	$ 978,881,050
Transmission Plant	NTPLANT	NTTRN	12CP	$ 72,135,404	$ 19,161,559	$ 59,851,968	$ 151,148,931
Distribution Substation	NTPLANT	NTDST	SUBA	$ -	$ -	$ -	$ -
Distribution Other	NTPLANT	NTDMC	Cust05	$ -	$ -	$ -	$ -
Total		NTPLT		$ 539,303,640	$ 143,256,961	$ 447,469,380	$ 1,130,029,981

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
August 31, 2014

Description	Ref	Name	Allocation Vector		Rurals		Large Industrials		Smelter		Total System
<u>Net Cost Rate Base</u>											
Power Production Plant											
Production Demand	RB	RBPDMD	12CP	$	497,742,718	$	132,217,000	$	412,985,578	$	1,042,945,296
Production Energy	RB	RBPENG	PENG	$	12,510,765	$	4,845,523	$	16,221,286	$	33,577,574
Production - Steam Direct	RB	RBPSTM	STMD	$	-	$	-	$	-	$	-
Total Power Production Plant		RBPT		$	510,253,483	$	137,062,523	$	429,206,864	$	1,076,522,870
Transmission Plant	RB	RBTRN	12CP	$	76,921,009	$	20,432,775	$	63,822,666	$	161,176,450
Distribution Substation	RB	RBDST	SUBA	$	-	$	-	$	-	$	-
Distribution Other	RB	RBDMC	Cust05	$	-	$	-	$	-	$	-
Total		RBPLT		$	587,174,492	$	157,495,298	$	493,029,531	$	1,237,699,320

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
August 31, 2014

Description	Ref	Name	Allocation Vector	Rurals	Large Industrials	Smelter	Total System
Operation and Maintenance Expenses							
Power Production Plant				[redacted]			
Production Demand	TOM	OMPDMD	12CP				
Production Demand Reallocation of Purchased Power							
Production Energy	TOM	OMPENG	PENG				
Production - Steam Direct	TOM	OMPSTM	STMD				
Total Power Production Plant		OMPT					
Transmission Plant	TOM	OMTRN	12CP	$ 9,207,250	$ 2,445,751	$ 7,639,412	$ 19,292,413
Distribution Substation	TOM	OMDST	SUBA	$ -	$ -	$ -	$ -
Distribution Other	TOM	OMDMC	Cust05	$ -	$ -	$ -	$ -
Total		OMPLT		[redacted]			

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
August 31, 2014

Description	Ref	Name	Allocation Vector		Rurals		Large Industrials		Smelter		Total System
Labor Expenses											
Power Production Plant											
Production Demand	TLB	LBPDMD	12CP	$	12,316,750	$	3,271,738	$	10,219,416	$	25,807,904
Production Energy	TLB	LBPENG	PENG	$	7,604,712	$	2,945,368	$	9,860,166	$	20,410,246
Production - Steam Direct	TLB	LBPSTM	STMD	$	-	$	-	$	-	$	-
Total Power Production Plant		LBPT		$	19,921,462	$	6,217,106	$	20,079,582	$	46,218,150
Transmission Plant	TLB	LBTRN	12CP	$	3,635,685	$	965,759	$	3,016,589	$	7,618,033
Distribution Substation	TLB	LBDST	SUBA	$	-	$	-	$	-	$	-
Distribution Other	TLB	LBDMC	Cust05	$	-	$	-	$	-	$	-
Total		LBPLT		$	23,557,147	$	7,182,865	$	23,096,172	$	53,836,183

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
August 31, 2014

Description	Ref	Name	Allocation Vector		Rurals		Large Industrials		Smelter		Total System
Depreciation Expenses											
Power Production Plant											
Production Demand	TDEPR	DPPDMD	12CP	$	18,436,665	$	4,897,391	$	15,297,214	$	38,631,270
Production Energy	TDEPR	DPPENG	PENG	$	-	$	-	$	-	$	-
Production - Steam Direct	TDEPR	DPPSTM	STMD	$	-	$	-	$	-	$	-
Total Power Production Plant		DPPT		$	18,436,665	$	4,897,391	$	15,297,214	$	38,631,270
Transmission Plant	TDEPR	DPTRN	12CP	$	2,611,376	$	693,668	$	2,166,703	$	5,471,746
Distribution Substation	TDEPR	DPDST	SUBA	$	-	$	-	$	-	$	-
Distribution Other	TDEPR	DPDMC	Cust05	$	-	$	-	$	-	$	-
Total		DPPLT		$	21,048,041	$	5,591,059	$	17,463,916	$	44,103,016

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
August 31, 2014

Description	Ref	Name	Allocation Vector		Rurals		Large Industrials		Smelter		Total System
Property and Other Taxes											
Power Production Plant											
Production Demand	PTAX	PRPDMD	12CP	$	368	$	98	$	305	$	771
Production Energy	PTAX	PRPENG	PENG	$	-	$	-	$	-	$	-
Production - Steam Direct	PTAX	PRPSTM	STMD	$	-	$	-	$	-	$	-
Total Power Production Plant		PRPT		$	368	$	98	$	305	$	771
Transmission Plant	PTAX	PRTRN	12CP	$	54	$	14	$	45	$	114
Distribution Substation	PTAX	PRDST	SUBA	$	-	$	-	$	-	$	-
Distribution Other	PTAX	PRDMC	Cust05	$	-	$	-	$	-	$	-
Total		PRPLT		$	422	$	112	$	350	$	885

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
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Description	Ref	Name	Allocation Vector		Rurals		Large Industrials		Smelter		Total System
Interest Expenses											
Power Production Plant											
Production Demand	INTLTD	INPDMD	12CP	$	19,538,256	$	5,190,010	$	16,211,222	$	40,939,488
Production Energy	INTLTD	INPENG	PENG	$	-	$	-	$	-	$	-
Production - Steam Direct	INTLTD	INPSTM	STMD	$	-	$	-	$	-	$	-
Total Power Production Plant		INPT		$	19,538,256	$	5,190,010	$	16,211,222	$	40,939,488
Transmission Plant	INTLTD	INTRN	12CP	$	2,884,388	$	766,189	$	2,393,226	$	6,043,803
Distribution Substation	INTLTD	INDST	SUBA	$	-	$	-	$	-	$	-
Distribution Other	INTLTD	INDMC	Cust05	$	-	$	-	$	-	$	-
Total		INPLT		$	22,422,644	$	5,956,199	$	18,604,448	$	46,983,291

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
August 31, 2014

Description	Ref	Name	Allocation Vector	Rurals	Large Industrials	Smelter	Total System
				$ 20,946,808	$ 8,112,872	$ 27,159,344	
Cost of Service Summary -- Unadjusted				$ -	$ -	$ -	
Operating Revenues							
Sales to Members		REVUC	R01	[redacted]			
Off System Sales Revenue			OSS				
Income from Leased Property Net		OTHREV	RBPLT				
Other Operating Revenue & Income		OTHREV	RBPLT				
Total Operating Revenues		TOR		$ 160,876,297	$ 54,666,177	$ 192,445,870	$ 407,988,345
Operating Expenses							
Operation and Maintenance Expenses				[redacted]			
Depreciation and Amortization Expenses				$ 21,048,041	$ 5,591,059	$ 17,463,916	$ 44,103,016
Property and Other Taxes			NPT	$ 422	$ 112	$ 350	$ 885
Total Operating Expenses		TOE		[redacted]			
Utility Operating Margin				[redacted]			
Non-Operating Items							
Interest Income			RBPLT	$ 936,888	$ 251,298	$ 786,672	$ 1,974,858
Other Non-Operating Income			RBPLT	$ -	$ -	$ -	$ -
Other Capital Credits & Patronage Dividends			RBPLT	$ 1,283,960	$ 344,391	$ 1,078,096	$ 2,706,448
Total Non-Operating Items				$ 2,220,849	$ 595,689	$ 1,864,768	$ 4,681,305
Net Utility Operating Margin		TOM		[redacted]			
Net Cost Rate Base				[redacted]			
Rate of Return on Rate Base (Unadjusted)				-2.46%	-2.89%	-0.31%	-1.66%

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
August 31, 2014

Description	Ref	Name	Allocation Vector		Rurals		Large Industrials		Smelter		Total System
Cost of Service Summary -- Pro-Forma (Before Proposed Rate Increase)											
Operating Revenues											
Total Operating Revenue				$	160,876,297	$	54,666,177	$	192,445,870	$	407,988,345
Pro-Forma Adjustments:											
To Remove Fuel Adjustment Clause Revenue		1.01		$	(12,526,275)	$	(4,836,245)	$	(16,176,808)	$	(33,539,328)
To Remove Environmental Surcharge Revenue		1.02		$	(8,718,352)	$	(2,933,572)	$	(8,938,660)	$	(20,590,584)
To Remove Non-FAC PPA Revenue		1.03		$	1,903,467	$	737,229	$	1,165,347	$	3,806,042
Total Pro-Forma Operating Revenue				$	141,535,138	$	47,633,588	$	168,495,749	$	357,664,475

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
August 31, 2014

Description	Ref	Name	Allocation Vector	Rurals	Large Industrials	Smelter	Total System
Cost of Service Summary -- Pro-Forma (Before Proposed Rate Increase) (cont.)							
Operating Expenses							
Operation and Maintenance Expenses				[redacted]			
Depreciation and Amortization Expenses				$ 21,048,041	$ 5,591,059	$ 17,463,916	$ 44,103,016
Property and Other Taxes			NPT	$ 422	$ 112	$ 350	$ 885
Adjustments to Operating Expenses:							
To Remove Fuel Expense Recoverable through the FAC		1.01		$ (12,526,275)	$ (4,836,245)	$ (16,176,808)	$ (33,539,328)
To Remove Expenses Recoverable through the ES		1.02		$ (8,718,352)	$ (2,933,572)	$ (8,938,660)	$ (20,590,584)
To Remove NFPPA		1.03		$ 1,903,467	$ 737,229	$ 1,165,347	$ 3,806,042
To Remove Promotional Advertising		1.04	R01	$ (22,133)	$ (7,382)	$ (26,241)	$ (55,756)
To Remove Lobbying Expenses		1.05	R01	$ (27,003)	$ (9,006)	$ (32,015)	$ (68,023)
To Remove Economic Development Expenses		1.06	R01	$ (55,717)	$ (18,582)	$ (66,058)	$ (140,357)
To Remove Donations Expenses		1.07	R01	$ (25,139)	$ (8,384)	$ (29,805)	$ (63,328)
To Remove Touchstone Energy dues		1.08	R01	$ (52,704)	$ (17,577)	$ (62,485)	$ (132,766)
To Amortize Rate Case Expenses - Case No. 2011-00036		1.09	RBPLT	$ 303,978	$ 81,535	$ 255,240	$ 640,753
To Remove Non-Recurring Labor related to Wilson Layup		1.10	LBPLT	$ (1,135,697)	$ (346,288)	$ (1,113,473)	$ (2,595,458)
To Normalize Certain Outside Professional Services		1.11	EnergyNS	$ (192)	$ (75)	$ -	$ (267)
To Remove Forecast Demand Side Management Expenses		1.12	12CP	$ (539,916)	$ (143,420)	$ (447,978)	$ (1,131,314)
To Normalized Demand Side Management Expenses		1.12	EnergyR	$ 1,000,000	$ -	$ -	$ 1,000,000
Total Expense Adjustments				$ (19,895,683)	$ (7,501,766)	$ (25,472,937)	$ (52,870,386)
Total Operating Expenses		TOE		[redacted]			
Utility Operating Margins -- Pro-Forma				[redacted]			
Non-Operating Items				$ -	$ -	$ -	$ -
Sum of Non-Operating Items				$ 2,220,849	$ 595,689	$ 1,864,768	$ 4,681,305
Adjustments to Non-Operating Items			12CP	$ -	$ -	$ -	$ -
Total Non-Operating Items				$ 2,220,849	$ 595,689	$ 1,864,768	$ 4,681,305
Net Utility Operating Margin				[redacted]			
Net Cost Rate Base				[redacted]			
Rate of Return on Rate Base -- Pro Forma (Before Proposed Rate Increase)				**-2.37%**	**-2.59%**	**-0.01%**	**-1.45%**

Case No. 2012-00535
Exhibit Wolfram-4

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
August 31, 2014

Description	Ref	Name	Allocation Vector	Rurals	Large Industrials	Smelter	Total System
<u>Cost of Service Summary -- Pro-Forma (After Proposed Rate Increase)</u>							
Operating Revenues							
Total Operating Revenue				$ 141,535,138	$ 47,633,588	$ 168,495,749	$ 357,664,475
Pro-Forma Adjustments: To Reflect Proposed Increase				$ 40,676,278	$ 8,247,929	$ 25,551,913	$ 74,476,120
Total Pro-Forma Operating Revenue				$ 182,211,416	$ 55,881,517	$ 194,047,662	$ 432,140,595
Operating Expenses							
Total Operating Expenses				[redacted]			
Utility Operating Margins -- Pro-Formed for Increase				[redacted]			
Net Cost Rate Base				[redacted]			
Rate of Return -- Pro Forma (After Proposed Rate Increase)				**4.18%**	**2.27%**	**4.80%**	**4.18%**
					-1.92%		
Average $/MWH Annual				56.71	48.83	51.85	53.23
Average Load Factor Monthly				0.63	0.91	0.98	0.80

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
August 31, 2014

Description	Ref	Name	Allocation Vector	Rurals	Large Industrials	Smelter	Total System
Allocation Factors							
Energy Allocation Factors							
Energy Usage by Class		E01	Energy	0.372593	0.144308	0.483099	1.000000
Customer Allocation Factors							
Rev		R01		138,121,080	46,064,053	163,756,402	347,941,535
Energy		Energy		2,436,557,000	943,698,679	3,159,206,400	6,539,462,079
FAC Revenue Allocator		FACA		2,436,557,000	943,698,679	3,159,206,400	6,539,462,079
Base Fuel Revenue Allocator		BSFL		2,436,557,000	943,698,679	3,159,206,400	6,539,462,079
Fuel Expense Applicable to FAC Allocator		FACEX		2,436,557,000	943,698,679	3,159,206,400	6,539,462,079
Energy - NonSmelter		EnergyNS		0.7208	0.2792	-	1.0000
Energy - Smelter only		EnergyS		-	-	1.0000	1.0000
Energy - Rurals only		EnergyR		1.0000	-	-	1.0000
Customers (Metering Points)		Cust05		3	1	1	5
Demand Allocators							
Steam - Direct Assignment		STMD		-	-	-	-
Substation Allocator		SUBA		-	-	-	-
Coincident Peak Demand CP		12CP		5,322,297	1,413,779	4,416,000	11,152,076
Non-Coincident Peak Demands NCP		NCP		5,376,057	1,674,594	4,416,000	11,466,651

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
August 31, 2014

Description	Ref	Name	Allocation Vector	Rurals	Large Industrials	Smelter	Total System
Production Energy Allocation							
Production Energy Residual Allocator		PENGA		2,436,557,000	943,698,679	3,159,206,400	6,539,462,079
Production Energy Costs				-	-	-	-
Member Specific Assignment				-	-	-	-
Production Energy Residual			PENGA	103,999,802	40,279,984	134,844,718	279,124,504
Production Energy Total		PENGT		103,999,802	40,279,984	134,844,718	279,124,504
Production Energy Total Allocator		PENG	PENGT	0.372593	0.144308	0.483099	1.000000
FAC Expense Residual Allocator		FACALL		2,436,557,000	943,698,679	3,159,206,400	6,539,462,079
FAC Expense Cost				-	-	-	-
Member Specific Assignment				-	-	-	-
FAC Expense Residual			FACALL	-	-	-	-
FAC Expense Total		FACT		-	-	-	-
FAC Expense Allocator		FACAL	12CP	0.372593	0.144308	0.483099	1.000000
OSS Allocated Amount		OSSA		[redacted]			
Off-System Sales Allocator							
Off-System Sales Revenue			OSSA	[redacted]			
Specific Assignment							
Total OSS Assignments		OSS					
				-	-	-	-

Case No. 2012-00535
Exhibit Wolfram-4

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
August 31, 2014

Description	Ref	Name	Allocation Vector	Rurals	Large Industrials	Smelter	Total System
Operating Expenses							
Expenses before Adjustments							
Production Demand				[redacted]			
Production Energy							
Transmission Demand				$ 11,818,680	$ 3,139,434	$ 9,806,159	$ 24,764,273
Total				[redacted]			
Expenses After Revenue Offsets							
Production Demand				[redacted]			
Production Energy							
Transmission Demand				$ 11,818,680	$ 3,139,434	$ 9,806,159	$ 24,764,273
Total				[redacted]			
Rate Base							
Production Demand				[redacted]			
Production Energy							
Transmission Demand				$ 76,921,009	$ 20,432,775	$ 63,822,666	$ 161,176,450
Total				[redacted]			
Operating Expenses-Unit Costs							
Production Demand ($/kW)				[redacted]			
Production Energy ($/kWh)							
Transmission Demand ($/kW)				2.22	2.22	2.22	2.22
Rate Base-Unit Costs							
Production Demand ($/kW)				[redacted]			
Production Energy ($/kWh)							
Transmission Demand ($/kW)				14.45	14.45	14.45	14.45

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
August 31, 2014

Description	Ref	Name	Allocation Vector	Rurals	Large Industrials	Smelter	Total System
Revenue Requirement Assuming a Rate of Return of	4.18%						
Production Demand				[redacted]			
Production Energy							
Transmission Demand				15,037,418	3,994,438	12,476,801	31,508,657
Total Revenue Requirement				[redacted]			
Unit Revenue Requirement							
Production Demand				[redacted]			
Production Demand (Per kW)							
Production Demand Margin (Per kW)							
Total Production Demand (Per kW)							
Production Energy				[redacted]			
Production Energy - (Per kWh)							
Production Energy Margin - (Per kWh)							
Total Production Energy (Per kWh)							
Transmission Demand							
Transmission Demand (per kW)				2.22	2.22	2.22	2.22
Tranmission Margin (Per kW)				0.02	0.02	0.02	0.02
Total Transmission Demand (per kW)				2.24	2.24	2.24	2.24

Exhibit Wolfram-5
Billing Determinants: Present and Proposed Rates

Exhibit Wolfram-5

Billing Determinants:

Present & Proposed Rates

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Billing Determinants - Present and Proposed Rates

12 Months Ended
August 31, 2014

Rate		Billing Determinants	Current Rate Charge	Current Rate Billings	Proposed Rate Charge	Proposed Rate Billings	Variance Billings
Rural Delivery Point Service							
Demand Charge	CP	5,322,297 kW-Mo	9.50 /kW-Mo	$ 50,561,820	16.95 /kW-Mo	$ 90,190,052	$ 39,628,232
Energy Charge		2,436,557,000 kWh	$ 0.029736 /kWh	72,453,459	$ 0.030000 /kWh	73,096,710	643,251
Total Demand and Energy Charges			0.050487	$ 123,015,279	0.067015	$ 163,286,762	$ 40,271,483
Non-Smelter Non-FAC PPA			(0.000781)	(1,903,467)	(0.000781)	(1,903,467)	-
FAC			0.005141	12,526,275	0.005141	12,526,275	-
Environmental Surcharge			0.003578	8,718,352	0.003744	9,123,147	404,795
Surcredit			(0.001738)	(4,235,358)	(0.001738)	(4,235,358)	-
Total		2,436,557,000 kWh	0.056687	$ 138,121,080	0.073381	$ 178,797,359	$ 40,676,278
Increase	$					$ 40,676,278	
Increase	%					29.4%	
Large Industrial Customer Delivery Point Service							
Demand Charge	NCP	1,674,594 kW-Mo	10.50 /kW-Mo	$ 17,583,237	12.41 /kW-Mo	$ 20,788,374	$ 3,205,137
Energy Charge		943,698,679 kWh	$ 0.024505 /kWh	23,125,336	$ 0.030000 /kWh	$ 28,310,960	$ 5,185,624
Total Demand and Energy Charges			0.043137	$ 40,708,573		$ 49,099,334	$ 8,390,761
Non-Smelter Non-FAC PPA			(0.000781)	(737,229)	(0.000781)	(737,229)	-
FAC			0.005125	4,836,245	0.005125	4,836,245	-
Environmental Surcharge			0.003109	2,933,572	0.002957	2,790,740	(142,833)
Surcredit			(0.001777)	(1,677,110)	(0.001777)	(1,677,110)	-
Total		943,698,679 kWh	0.048812	$ 46,064,053	0.057552	$ 54,311,981	$ 8,247,929
Increase	$					$ 8,247,929	
Increase	%					17.9%	

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Billing Determinants - Present and Proposed Rates

12 Months Ended
August 31, 2014

Rate	Billing Determinants		Current Rate Charge	Current Rate Billings	Proposed Rate Charge	Proposed Rate Billings	Variance Billings
Smelter							
Base Energy Charge							
Base Fixed Energy Charge	3,159,206,400	kWh	0.039432 /kWh	$ 124,573,827	$ 0.047603 /kWh	$ 150,387,702	$ 25,813,875
Base Variable Energy Charge	-	kWh	0.012470 /kWh	-	$ 0.021806 /kWh	-	-
Total Base Energy Charge	3,159,206,400	kWh	0.039432	$ 124,573,827		$ 150,387,702	$ 25,813,875
Other Charges or Credits							
TIER Adjustment Charge			0.002950	$ 9,319,659	0.002950	$ 9,319,659	$ -
Non-FAC PPA			(0.000369)	(1,165,347)	(0.000369)	$ (1,165,347)	-
FAC			0.005121	16,176,808	0.005121	$ 16,176,808	-
Environmental Surcharge			0.002829	8,938,660	0.002746	$ 8,676,698	(261,962)
Surcharge			0.001872	5,912,468	0.001872	$ 5,912,468	-
Total	3,159,206,400		0.051835	$ 163,756,075	0.059923	$ 189,307,988	$ 25,551,913
Increase $						$ 25,551,913	
Increase %						15.6%	
TOTAL	6,539,462,079		0.053206	$ 347,941,208	0.064595	$ 422,417,328	$ 74,476,120
INCREASE					0.011389	$ 74,476,120 21.40%	

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Billing Determinants - Present and Proposed Rates

12 Months Ended
August 31, 2014

Rate	Billing Determinants	Current Rate Charge	Current Rate Billings	Proposed Rate Charge	Proposed Rate Billings	Variance Billings

Notes

Note A: Base Rate is the rate resulting from the application of the Large Industrial Rate to a load with a 98% load factor, plus $0.0025/kWh.

	Current	*Proposed*	
Large Industrial Demand Charge	10.50	12.41	
Hours {730 hrs * 98%}	715.4	715.4	
Demand Charge per kWh	$ 0.014677	$ 0.017353	
Energy Charge	0.024505	0.030000	
Plus:	0.000250	0.000250	
Total	$ 0.039432	$ 0.047603	

Note B: Base Variable Energy Charge equals the total of the FAC Base, Environmental Surcharge Base, and Non-FAC PPA Base

	Current	Proposed	
FAC Base	$ 0.01072	$ 0.01072	$ 0.0209
Environmental Surcharge Base	-	-	
Non-FAC PPA Base	0.000874	0.000874	
Total Base Variable Energy Charge	$ 0.012470	$ 0.011594	

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Billing Determinants - Present and Proposed Rates

12 Months Ended
August 31, 2014

Rate		Billing Determinants	Current Rate Charge		Current Rate Billings	Proposed Rate Charge		Proposed Rate Billings	Variance Billings
Notes	Note C: ES is calculated on the basis of Total Adjusted Revenues								
		ES Revenues	42%	R	$ 8,718,352	44%	R	$ 9,123,147	$ 404,795
			14%	LI	$ 2,933,572	14%	LI	$ 2,790,740	$ (142,833)
			43%	S	$ 8,938,660	42%	S	$ 8,676,698	$ (261,962)
			100%	Total	$ 20,590,584	100%	Total	$ 20,590,584	$ -
		Total Adj Revenue	42%	R	$ 133,638,087	44%	R	$ 173,909,570	$ 40,271,483
			14%	LI	$ 44,807,590	14%	LI	$ 53,198,351	$ 8,390,761
			44%	S	$ 139,585,288	42%	S	$ 165,399,163	$ 25,813,875
			100%	Total	$ 318,030,964	100%	Total	$ 392,507,084	$ 74,476,120
	Note D: Retail rate increases estimated using approximate distribution cost adder								
		RDS Distr Adder	0.03300						
		LIC Dist Adder	0.00200						
		RDS	0.089687			0.106381			0.016694 19%
		LIC	0.050812			0.059552			0.008740 17%

Exhibit Wolfram-6
Summary of Proposed Increase

Exhibit Wolfram-6

Summary of Proposed Increase

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Summary of Proposed Increase

12 Months Ended
August 31, 2014

Class	Total Revenue at Current Rates ($)	Total Revenue at Proposed Rates ($)	Increase ($)	Increase (%)
Rural	138,121,080	178,797,359	40,676,278	29.4%
Large Industrial	46,064,053	54,311,981	8,247,929	17.9%
Smelter	163,756,075	189,307,988	25,551,913	15.6%
Total	347,941,208	422,417,328	74,476,120	21.4%

Exhibit Wolfram-7
Estimate of Retail Rate Increase

Exhibit Wolfram-7

Estimate of Retail Rate Increase

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Estimate of Retail Rate Increase

12 Months Ended
August 31, 2014

Rural Delivery Service

		Current	Proposed	Increase	Increase
Estimated Retail Rate ($/kWh)					
All-In Wholesale Rate		0.056687	0.073381	0.016694	29.4%
Estimated Retail Distr Cost Adder		0.033000	0.033000		
Total Retail Rate Estimate		0.089687	0.106381	0.016694	18.6%
Estimated Billings ($/Month)					
Monthly Usage	100 kWh	$ 8.97	$ 10.64	$ 1.67	18.6%
	200	$ 17.94	$ 21.28	$ 3.34	18.6%
	300	$ 26.91	$ 31.91	$ 5.00	18.6%
	400	$ 35.87	$ 42.55	$ 6.68	18.6%
	500	$ 44.84	$ 53.19	$ 8.35	18.6%
	600	$ 53.81	$ 63.83	$ 10.02	18.6%
	700	$ 62.78	$ 74.47	$ 11.69	18.6%
	800	$ 71.75	$ 85.10	$ 13.35	18.6%
	900	$ 80.72	$ 95.74	$ 15.02	18.6%
	1000	$ 89.69	$ 106.38	$ 16.69	18.6%
	1100	$ 98.66	$ 117.02	$ 18.36	18.6%
	1200	$ 107.62	$ 127.66	$ 20.04	18.6%
	1300	$ 116.59	$ 138.30	$ 21.71	18.6%
	1400	$ 125.56	$ 148.93	$ 23.37	18.6%
	1500	$ 134.53	$ 159.57	$ 25.04	18.6%

Large Industrial Customer Service

		Current	Proposed	Increase	Increase
Estimated Retail Rate ($/kWh)					
All-In Wholesale Rate		0.048812	0.057552	0.008740	17.9%
Estimated Retail Distribution Cost Adder		0.002000	0.002000		
Total Retail Rate Estimate		0.050812	0.059552	0.008740	17.2%
Estimated Billings ($/Month)					
Monthly Usage	500 kWh	$ 25.41	$ 29.78	$ 4.37	17.2%
	600	$ 30.49	$ 35.73	$ 5.24	17.2%
	700	$ 35.57	$ 41.69	$ 6.12	17.2%
	800	$ 40.65	$ 47.64	$ 6.99	17.2%
	900	$ 45.73	$ 53.60	$ 7.87	17.2%
	1000	$ 50.81	$ 59.55	$ 8.74	17.2%
	1100	$ 55.89	$ 65.51	$ 9.61	17.2%
	1200	$ 60.97	$ 71.46	$ 10.49	17.2%
	1300	$ 66.06	$ 77.42	$ 11.36	17.2%
	1400	$ 71.14	$ 83.37	$ 12.24	17.2%
	1500	$ 76.22	$ 89.33	$ 13.11	17.2%
	1600	$ 81.30	$ 95.28	$ 13.98	17.2%
	1700	$ 86.38	$ 101.24	$ 14.86	17.2%
	1800	$ 91.46	$ 107.19	$ 15.73	17.2%
	1900	$ 96.54	$ 113.15	$ 16.61	17.2%
	2000	$ 101.62	$ 119.10	$ 17.48	17.2%