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AUG 15 2012

PUBLIC SERVICE
COMMISSION

August 14, 2012

Jeff DeRouen
Executive Director
Public Service Commission
211 Sower Boulevard, P.O. Box 615
Frankfort, Kentucky 40602-0615

Re: *In the Matter of: Application of Big Rivers Electric Corporation for Approval of its 2012 Environmental Compliance Plan, for Approval of its Amended Environmental Cost Recovery Surcharge Tariff, for Certificates of Public Convenience and Necessity, and for Authority to Establish a Regulatory Account,* P.S.C. Case No. 2012-00063

Dear Mr. DeRouen:

Attached hereto are Big Rivers Electric Corporation's updated responses to selected data requests received in Case No. 2012-00063. These responses are a *Third Updated* response to Item 1 of the Commission Staff's Initial Request for Information dated May 21, 2012, a *Second Updated* response to Item 44 of the Kentucky Industrial Utility Customers' Initial Request for Information dated May 21, 2012, a *First Updated* response to Item 56 and 57 of the Sierra Club's Initial Request for Information dated May 21, 2012, and a *First Updated* response to Item 3 of Kentucky Industrial Utility Customers' Second Request for Information dated June 22, 2012.

Please confirm the Commission's receipt of this information by placing the Commission's file stamp on the enclosed additional copy of this letter and returning it to Big Rivers in the self-addressed, postage paid envelope provided herein.

Sincerely,

Tyson Kamuf
TAK/ej

Enclosures
cc: Albert Yockey
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BIG RIVERS ELECTRIC CORPORATION

THE APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR APPROVAL OF ITS 2012 ENVIRONMENTAL COMPLIANCE PLAN AND REVISIONS TO ITS ENVIRONMENTAL SURCHARGE TARIFF, FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY, AND FOR AUTHORITY TO ESTABLISH A REGULATORY ACCOUNT

CASE NO. 2012-00063

VERIFICATION

I, Ralph A. Ashworth, verify, state, and affirm that I prepared or supervised the preparation of the data responses filed with this Verification, and that those data responses are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Ralph A. Ashworth

Ralph A. Ashworth

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Ralph A. Ashworth on this the 14th day of August, 2012.

Paula Mitchell

Notary Public, Ky. State at Large
My Commission Expires 1-12-13

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 APPROVAL OF ITS 2012 ENVIRONMENTAL COMPLIANCE PLAN, FOR APPROVAL OF ITS AMENDED ENVIRONMENTAL COST RECOVERY SURCHARGE TARIFF, FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY, AND FOR AUTHORITY TO ESTABLISH A REGULATORY ACCOUNT	)	Case No. 2012-00063

Third Updated Response to Commission Staff's
Initial Request for Information dated May 21, 2012

Second Updated Response to Kentucky Industrial Utility Customers'
Initial Request for Information dated May 21, 2012

First Updated Response to the Sierra Club's
Initial Request for Information dated May 21, 2012

First Updated Response to Kentucky Industrial Utility Customers'
Second Request for Information dated June 22, 2012

FILED: August 15, 2012

ORIGINAL

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR APPROVAL OF ITS 2012 ENVIRONMENTAL COMPLIANCE PLAN,
FOR APPROVAL OF ITS AMENDED ENVIRONMENTAL COST
RECOVERY SURCHARGE TARIFF, FOR CERTIFICATES OF PUBLIC
CONVENIENCE AND NECESSITY, AND FOR AUTHORITY TO
ESTABLISH A REGULATORY ACCOUNT
CASE NO. 2012-00063

Third Updated Response to Commission Staff's
Initial Request for Information
Dated May 21, 2012

June 1, 2012
First Update June 15, 2012
Second Update July 16, 2012
Third Update August 15, 2012

Item 1) *Refer to the Application, page 7, which states that Big Rivers is requesting authority to establish a regulatory account. The Application states, "[a]s explained further in Mr. Hite's testimony, Big Rivers has incurred costs in developing this Application, and it will incur additional costs to prosecute this case. These costs primarily stem from the retention of experts in the legal, regulatory, and engineering professions." Provide the actual costs incurred to date by type and vendor. Consider this an ongoing request to be updated by the 15th of the month, to report the prior month's expense, for each month up to and including the month of the hearing in this case.*

Response) Attached hereto is Big Rivers' August 15th update for the costs incurred to-date in its Environmental Compliance Plan Application.

Witness) Ralph A. Ashworth

Big Rivers Electric Corporation
Case No. 2012-00063
Cost Incurred To-date for Environmental Compliance Plan Application
Third Update to Big Rivers' Response to Item 1 of Commission Staff's Initial Request for Information dated May 21, 2012

Entity/Vendor	Amount	Invoice Number	Invoice Date	Purpose/Type
Total Per Response Dated July 13, 2012	**$ 322,260.14**			
Aces Power Marketing LLC	$ 8,298.00	12/5863-IN	7/12/2012	Risk Management Services
Catalyst Consulting LLC	9,778.18	101	7/1/2012	Consultants
GDS Associates Inc	510.00	0098430	6/20/2012	Consultants
Sargent and Lundy LLC	16,161.21	10798858	7/16/2012	Engineering Consultants
Sullivan, Mountjoy, Stainback	22,805.00	113,455	7/7/2012	Legal
Vantage Energy Consulting	23,940.00	20120602	7/1/2012	Commission Consultants
Total For the Remainder of July 2012	**$ 81,492.39**			
Total To-Date as of July 31, 2012	**$ 403,752.53**			

Note: Per Big Rivers' response to Item 1 of the Staff's Initial Request for Information, dated June 1, 2012, the estimated cost to develop and prosecute this Case is $900,000. Big Rivers will seek to update this estimate throughout the proceeding.

Case No. 2012-00063
Attachment for *Third Updated* Response to Item PSC 1-1
Witness: Ralph A. Ashworth

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR APPROVAL OF ITS 2012 ENVIRONMENTAL COMPLIANCE PLAN,
FOR APPROVAL OF ITS AMENDED ENVIRONMENTAL COST
RECOVERY SURCHARGE TARIFF, FOR CERTIFICATES OF PUBLIC
CONVENIENCE AND NECESSITY, AND FOR AUTHORITY TO
ESTABLISH A REGULATORY ACCOUNT
CASE NO. 2012-00063

Second Updated Response to the Kentucky Industrial Utility Customers' Initial Request for Information
Dated May 21, 2012

June 1, 2012
First Update July 16, 2012
Second Update August 15, 2012

Item 44) ***Please provide the current balance (as of April 2012 or May 2012, if available) in the Economic Reserve Fund and the Rural Economic Reserve ("RER") fund. This should be considered a continuing request and updates should be provided monthly as actual information for each succeeding month is available.***

Response) The month-end balances in the Economic Reserve fund account and in the Rural Economic Reserve (RER) fund account are shown in the table below.

Big Rivers Electric Corporation Fund Account Balances as of Listed Dates		
	Economic Reserve Fund	Rural Economic Reserve Fund
April 30, 2012	$ 93,878,033.55	$ 63,887,762.11
May 31, 2012	$ 92,253,460.12	$ 63,984,670.78
June 30, 2012	$ 90,341,556.06	$ 64,081,579.43
July 31, 2012	$ 88,400,701.87	$ 64,178,488.06

Witness) Ralph A. Ashworth

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR APPROVAL OF ITS 2012 ENVIRONMENTAL COMPLIANCE PLAN,
FOR APPROVAL OF ITS AMENDED ENVIRONMENTAL COST
RECOVERY SURCHARGE TARIFF, FOR CERTIFICATES OF PUBLIC
CONVENIENCE AND NECESSITY, AND FOR AUTHORITY TO
ESTABLISH A REGULATORY ACCOUNT
CASE NO. 2012-00063

First Updated Response to the Sierra Club's
Initial Request for Information
Dated May 21, 2012

June 1, 2012
First Update August 15, 2012

Item 56) *Refer to p. 15 of the testimony of Mark Hite.*

a. Produce all reports, memoranda, presentations, or other documents provided to the Rural Utilities Service ("RUS"), CoBank, or the National Rural Utilities Cooperative Finance Corporation ("CFC") by either Big Rivers or Touchstone Energy since 2004 regarding:

i. the environmental compliance status of the Wilson, Green, Coleman, Reid, or HMP&L generating units,

ii. past, present or future environmental compliance of the Wilson, Green, Coleman, Reid, or HMP&L generating units,

b. Please provide any application(s) for a loan or loan guarantee submitted to the RUS, CoBank, or CFC, including any supporting documentation for the loan or loan guarantee request, for the retrofits requested in these CPCNs for the Wilson, Green, Coleman, Reid, or HMP&L generating units;

c. Please provide any response from RUS, Co-Bank, or CFC regarding a request for a loan or loan guarantee for *retrofits proposed in this application of the Wilson, Green, Coleman, Reid, or HMP&L generating units.*

d. *If RUS, CoBank, or CFC has agreed to provide a loan or loan guarantee, please provide any loan or loan guarantee paperwork between RUS/CoBank/CFC and Big Rivers regarding the retrofit of the Wilson, Green, Coleman, Reid, or HMP&L generating units.*

e. *Please provide any environmental assessment or environmental impact statement, including any drafts, prepared to support a loan or loan guarantee from RUS, CoBank, or CFC for the retrofits of the Wilson, Green, Coleman, Reid, or HMP&L generating units*

f. *If no environmental assessment or environmental impact statement was prepared for the retrofits proposed in this application because one or more of these projects fall under a categorical exclusion, please provide any correspondence or documents from RUS that discuss application of the categorical exclusion.*

g. *Please continue to provide any such documentation as listed in (a)-(f) above as generated on a regular basis.*

Response)

a. Please refer to Exhibit DePriest–2, the S&L report which Big Rivers provided to RUS. In addition, attached is a presentation made by Big Rivers to CoBank on February 28, 2012; and the annual (2010, 2011, and 2012) letters from Big Rivers to RUS certifying Big Rivers has fulfilled all its obligations under its Loan Documents in all material respects, which include compliance with environmental laws. Also, please see Big Rivers' presentation to the Rural Utilities Service provided in the response to Item 64 of the Office of the Attorney General's Initial Request for Information.

b. None.

c. See attached (CFC Engagement Letter, Revolving Credit Facility, and Transaction Calendar).

d. None.

e. None.

f. None.

g. Big Rivers will update this response during the course of this proceeding. *Please see the Disclosure Statement provided in Big Rivers' First Updated response to Item 3 of the Kentucky*

Industrial Utility Customer's Second Request for Information dated June 22, 2012.

Witness) Ralph A. Ashworth

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR APPROVAL OF ITS 2012 ENVIRONMENTAL COMPLIANCE PLAN, FOR APPROVAL OF ITS AMENDED ENVIRONMENTAL COST RECOVERY SURCHARGE TARIFF, FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY, AND FOR AUTHORITY TO ESTABLISH A REGULATORY ACCOUNT
CASE NO. 2012-00063

First Updated Response to the Sierra Club's
Initial Request for Information
Dated May 21, 2012

June 1, 2012
First Update August 15, 2012

Item 57) *Refer to p. 15 of Mark A. Hite's Testimony, produce all reports, memoranda, presentations, or other documents provided to stockholders, investors, banks, investment firms, investment brokers or dealers, investment analysts, bond rating agencies, by either Big Rivers or Touchstone Energy since 2004 regarding:*

a. the environmental compliance status of the Wilson, Green, Coleman, Reid, or HMP&L generating units,

b. past, present or future environmental compliance of the Wilson, Green, Coleman, Reid, or HMP&L generating units,

c. litigation or settlements concerning environmental matters at the Wilson, Green, Coleman, Reid, or HMP&L generating units the Big Sandy plant, to the extent not covered by attorney-client privilege,

d. past, present or future need for the Wilson, Green, Coleman, Reid, or HMP&L generating units, or the need for or plans for capital additions to any of those units, whether for environmental compliance or otherwise, *e.* *any other matter that could affect the costs or output of the Wilson, Green, Coleman, Reid, or HMP&L generating units.*

f. *To the extent not already provided in response to subsections a-e above, please provide any agendas, handouts, minutes, documents prepared for or resulting from each meeting of Big Rivers and/or Touchstone Energy with stockholders, investors, banks, investment firms, investment brokers or dealers, investment analysts, bond rating agencies or the like at which the matters listed above were discussed in any way*

g. *Please continue to provide any such documentation as listed in (a)-(f) above as generated on a regular basis.*

Response) Please see the documents attached hereto, portions of which are being filed under a petition for confidential treatment. Also, please see the response to the Attorney General's Initial Data Request Items 31 and 32. In addition, see the response to the KIUC 's Initial Data request 1.43 in this proceeding.

a. See Item 56 of these responses.

b. See Item 56 of these responses.

c. None.

d. None.

e. This question is impossibly broad, fails to identify with specificity the information sought, and cannot be answered in its current form.

f. Not applicable.

g. Big Rivers will update this response during the course of this proceeding. *Please see the Disclosure Statement provided in Big Rivers' First Updated response to Item 3 of the Kentucky Industrial Utility Customer's Second Request for Information dated June 22, 2012.*

Witness) Ralph A. Ashworth

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR APPROVAL OF ITS 2012 ENVIRONMENTAL COMPLIANCE PLAN, FOR APPROVAL OF ITS AMENDED ENVIRONMENTAL COST RECOVERY SURCHARGE TARIFF, FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY, AND FOR AUTHORITY TO ESTABLISH A REGULATORY ACCOUNT
CASE NO. 2012-00063

First Updated Response to the Kentucky Industrial Utility Customers' Second Request for Information Dated June 22. 2012

July 6, 2012
First Update August 15. 2012

Item 3) ***Please provide all documents and other communications provided to Cobank and CFC since the filing of Big Rivers' responses to KIUC's Initial Request for Information. Please note this is a continuing request requiring updated information.***

Response) Please see the supporting documents which are provided in two sets. On the CONFIDENTIAL USB drive accompanying these responses are documents and other communications provided to CoBank and CFC in connection with KPSC Case No. 2012-00063 since June 1, 2012. These documents are being submitted with a Petition for Confidential Treatment. Other supporting documents are provided on a PUBLIC USB drive accompanying these responses.

There are only two documents pertaining to CoBank, as they are not currently involved in the planned CFC syndicated revolver for interim financing for Big Rivers' 2012 Environmental Compliance Plan ("ECP") capital expenditures. While the Disclosure Statement provided herein is principally in connection with the previously planned June 29, 2012, term loan financing, it was also used in connection with certain CFC inquiries regarding the up to $300 million CFC syndicated revolver for the purpose of interim financing for Big Rivers' 2012 ECP capital expenditures.

Please see the Disclosure Statement, date July 12, 2012, accompanying this response.

Witness) Ralph A. Ashworth

First Updated **Response to KIUC 2-3 [*Start*]**

Big Rivers Electric Corporation Disclosure Statement, July 12, 2012

Confidential

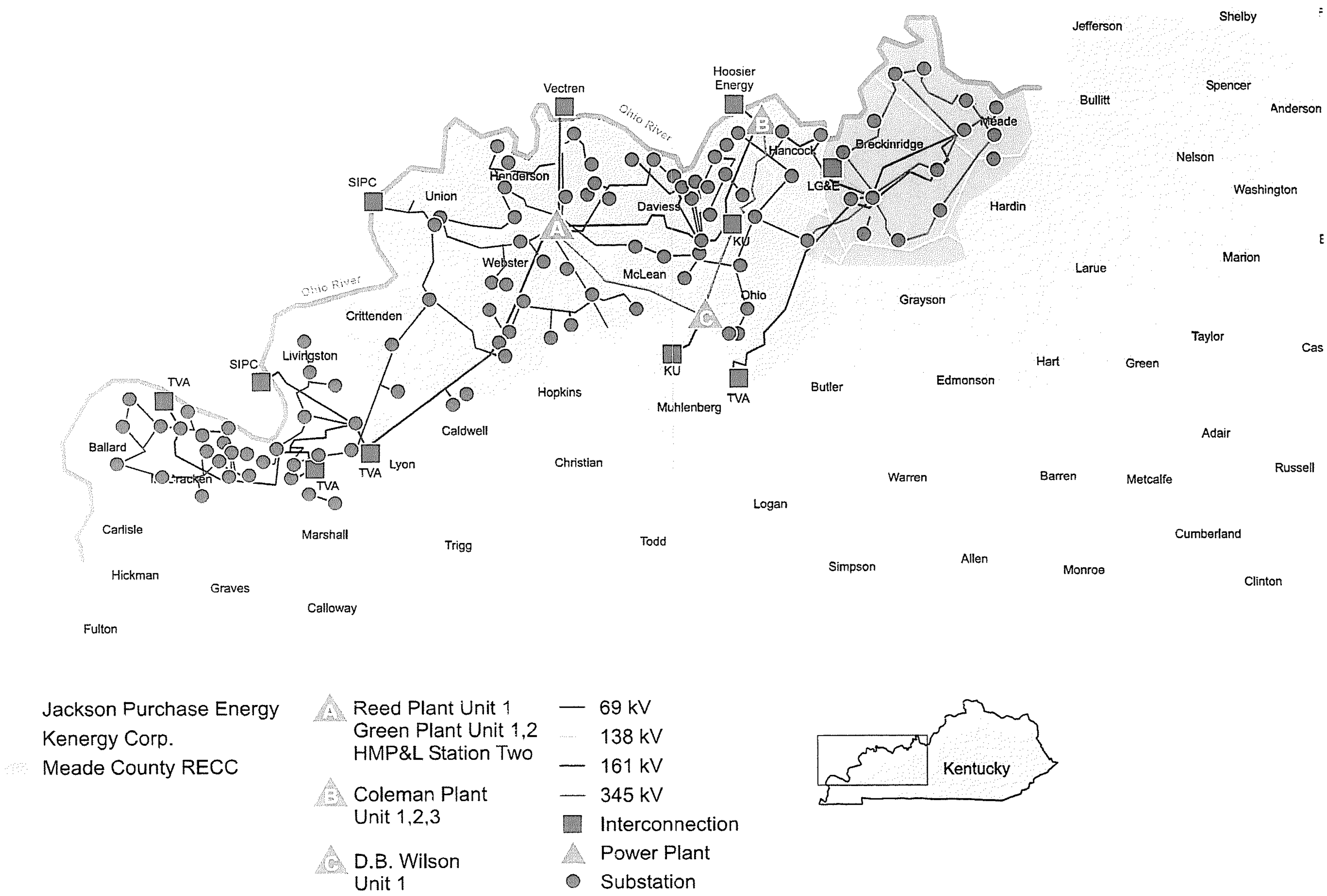
BIG RIVERS ELECTRIC CORPORATION

DISCLOSURE STATEMENT

July 12, 2012

TABLE OF CONTENTS

BIG RIVERS ELECTRIC CORPORATION 1
INTRODUCTION 1
SELECTED FINANCIAL DATA 7
CAPITALIZATION 9
MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS 10
RATE AND ENVIRONMENTAL REGULATIONS 23
QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK 34
BIG RIVERS' MEMBERS 37
THE SMELTER AGREEMENTS 38
POWER SUPPLY PLANNING 41
GENERATION AND TRANSMISSION ASSETS 41
MANAGEMENT 46
APPENDIX A – YEAR END FINANCIAL STATEMENTS A-1
APPENDIX B – MEMBER FINANCIAL AND STATISTICAL INFORMATION B-1
APPENDIX C – SUMMARY OF CERTAIN PROVISIONS OF THE MORTGAGE INDENTURE C-1
APPENDIX D – SUMMARY OF CERTAIN PROVISIONS OF THE SMELTER AGREEMENTS D-1


Jefferson
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Vectren
Ohio River
LG&E
KU
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McLean
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Simpson
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Monroe
Cumberland
Clinton
Carlisle
Hickman
Graves
Marshall
Trigg
Calloway
Fulton
Jackson Purchase Energy
Kenergy Corp.
Meade County RECC
Reed Plant Unit 1
Green Plant Unit 1,2
HMP&L Station Two
Coleman Plant
Unit 1,2,3
D.B. Wilson
Unit 1
69 kV
138 kV
161 kV
345 kV
Interconnection
Power Plant
Substation
Kentucky

Big Rivers Electric Corporation
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Henderson, Kentucky 42420

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Robert W. Berry, Vice President of Production

Senior Staff

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Mark A. Hite, Vice President of Accounting and Interim Chief Financial Officer
Eric M. Robeson, Vice President of Environmental Services and Construction
Albert M. Yockey, Vice President of Governmental Relations & Enterprise Risk Management

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Louis Wayne Elliott, Vice Chair
Larry F. Elder, Secretary-Treasurer
Lee Bearden
Paul Edd Butler
William C. Denton

Members

Kenergy Corp.
Jackson Purchase Energy Corporation
Meade County Rural Electric Cooperative Corporation

BIG RIVERS ELECTRIC CORPORATION

INTRODUCTION

General

Big Rivers Electric Corporation ("Big Rivers" or the "Company") is an electric generation and transmission ("G&T") rural electric cooperative corporation. It was organized as a not-for-profit rural electric cooperative under the laws of Kentucky in June, 1961 to enable its Members (as defined herein) to pool their resources and provide for the power and transmission needs of their combined service territories. The Company currently operates as a taxable cooperative. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS – Critical Accounting Policies – Accounting for Income Taxes." Big Rivers provides wholesale electric service to its three Members under a number of wholesale power contracts which contracts, in the aggregate, supply the total wholesale power requirements of the Members (see "Wholesale Power Contracts"), except the requirements of Kenergy Corp. ("Kenergy") for service to two aluminum smelters required by the Smelters Agreements (as defined herein). The two aluminum smelters are Rio Tinto Alcan ("Alcan"), a product group of Rio Tinto, and Century Aluminum of Kentucky General Partnership ("Century"), a wholly-owned subsidiary of Century Aluminum Company. Alcan and Century are referred to herein as the "Smelters." For a discussion of certain recent statements made on behalf of the Smelters, see the discussion under the caption "THE SMELTER AGREEMENTS."

Big Rivers owns 1,444 net MW of electric generating facilities, described herein under "GENERATION AND TRANSMISSION ASSETS – Generation Resources" and approximately 1,266 miles of transmission lines and 22 substations, described herein under "GENERATION AND TRANSMISSION ASSETS – Transmission."

In addition to its owned electric generation and transmission facilities, Big Rivers operates the 312 net MW Henderson Municipal Power and Light ("HMP&L") Station Two Generating Facility ("Station Two") in accordance with a Power Plant Construction and Operation Agreement dated August 1, 1970 between HMP&L and Big Rivers (the "Station Two Operation Agreement"), and purchases all the power and energy from Station Two not used by HMP&L to serve the needs of the City of Henderson, Kentucky (the "City" or the "City of Henderson"), in accordance with a Power Sales Contract between HMP&L and Big Rivers dated August 1, 1970 (the "Station Two Power Sales Contract"). See "GENERATION AND TRANSMISSION ASSETS – Other Power Supply Resources – *Station Two Facility*."

In 2011, the Company's average wholesale revenue per kWh to the Members, including amounts withdrawn from the economic reserve, was $.04678 per kWh for rural loads and $.04168 per kWh for large industrial loads (exclusive of the Smelter loads and Domtar cogenerator backup served by Kenergy). The Company's average wholesale revenue per kWh to Kenergy to serve the two Smelter loads in 2011 was $.04448 per kWh on sales of 6.9 million MWh. Excluding the Smelters, sales to its Members were 3.3 million MWh in 2011, 2.4 million MWh for rural loads and 0.9 million MWh for large industrial loads. Member Non-Smelter MWh sales in 2011 decreased by 2.0% from 2010. Rural loads in 2011 decreased by 4.4% from 2010 while large industrial loads increased by 4.3%. To the extent surplus capacity and energy are available, Big Rivers may sell electricity to non-Member utilities and power marketers ("Non-Members"). During 2011, the Company sold approximately 3.1 million MWh to Non-Members.

Cooperative Structure

In general, a cooperative is a business organization owned by its members, which are also its customers. Cooperatives provide goods or services to their members on a not-for-profit basis, in part by eliminating the need to produce profits or a return on equity in excess of required margins. Generally, electric cooperatives design rates on an overall basis to recover cost-of-service and collect a reasonable amount of revenue in excess of expenses (i.e., margins). Margins are typically repaid to the members in subsequent years on the basis of their patronage during the years the margins were earned.

A G&T cooperative is a cooperative engaged primarily in providing wholesale electricity to its members, which may be either wholesale or retail power suppliers. Electricity sold by a G&T cooperative is provided from its own generating facilities or through power purchase agreements with its wholesale power suppliers. A distribution cooperative is a local membership cooperative whose members are the individual retail customers of an electric distribution system.

The Members

The Members of Big Rivers are Kenergy, Meade County Rural Electric Cooperative Corporation ("Meade") and Jackson Purchase Energy Corporation ("Jackson Purchase", and collectively with Kenergy and Meade, the "Members"). The Members of Big Rivers are local consumer-owned distribution cooperatives providing retail electric service on a not-for-profit basis to their customers, who are their members. The customer base of the Members generally consists of residential, commercial and industrial consumers within specific geographic areas. The Members provide electric power and energy to customers located in portions of 22 western Kentucky counties. As of December 31, 2011, the Members served approximately 113,000 member-customers (meters). Kenergy has approximately 55,300 retail members, Meade has approximately 28,500 retail members and Jackson Purchase has approximately 29,200 retail members. See APPENDIX B – "MEMBER FINANCIAL AND STATISTICAL INFORMATION."

Bankruptcy and Subsequent Operation

In September 1996, Big Rivers filed a voluntary petition for relief under Chapter 11 of the United States Bankruptcy Code. The filing was precipitated largely by the Company's inability to sell its capacity in excess of that required to serve its Members at prices sufficient to cover all of its costs, which shortfall was exacerbated by long-term coal contracts under which prices had escalated well above market prices. In July 1998, a bankruptcy court-approved Plan of Reorganization (the "Plan of Reorganization") became effective. The Plan of Reorganization fundamentally changed the operations of the Company and resulted in the restructuring of the Company's long-term debt.

In accordance with the Plan of Reorganization, the Company leased all of its generating facilities to Western Kentucky Energy Corp. ("WKEC"), a wholly-owned subsidiary of LG&E Energy Corp. (LG&E, and subsequently E.ON U.S., LLC ("E.ON"). WKEC assumed and agreed to perform and discharge all of the Company's obligations under these assets that first arose or accrued on or after the effective date of the Plan of Reorganization. In addition to assuming responsibility for operation of the generating facilities owned by the Company, WKE Station Two Inc. ("WKE Station Two"), another wholly owned subsidiary of LG&E, assumed responsibility for the operation of Station Two and the Company's obligation to purchase power from Station Two under the Station Two Power Sales Contract. Pursuant to the Plan of Reorganization, WKEC and WKE Station Two (which was subsequently merged into WKEC) became responsible for the Company's prior responsibilities to operate and maintain the generating facilities owned by the Company and Station Two. Capital costs for these generating facilities were shared by WKEC and the Company in several different ratios depending upon whether or not the capital expenditures were incurred in order to comply with a state law enacted after the effective date of the Plan of Reorganization or a revision or change of an existing law enacted after such date. Operation and maintenance costs, including fuel, were, for the most part, the responsibility of WKEC.

The Plan of Reorganization (the "LG&E Arrangements") also included a power purchase agreement (the "LEM Power Purchase Agreement") between the Company and LG&E Energy Marketing Inc. ("LEM"). The LEM Power Purchase Agreement established minimum hourly and annual power purchase amounts that Big Rivers was required to take and certain maximum hourly and annual power purchase amounts that LEM was required to make available to the Company. The Company paid specified fixed rates for power purchased under the LEM Power Purchase Agreement that were not dependent upon market prices for electric power and energy nor the costs associated with power and energy generated by the generating facilities owned by the Company and operated by WKE Station Two.

Throughout the duration of the LG&E Arrangements Big Rivers received lease payments from WKEC of approximately $31 million annually. These lease payments were subject to adjustment for certain environmental costs and changes in the amount of power available to Big Rivers from LEM. The Company was responsible for 70% of all property taxes on the generating facilities leased to WKE Station Two during the LG&E Arrangements and WKEC paid 30%.

The Plan of Reorganization required LEM to pay Big Rivers an average of approximately $18 million annually, which amount corresponded to the estimated margins the Company had anticipated to realize from sales to its Members to supply the loads of the Smelters. The Plan of Reorganization also required the transfer of responsibility for providing the wholesale power and energy to Kenergy necessary to serve the needs of the Smelters from Big Rivers to LEM.

The Company provided transmission service to the Members and Non-Members pursuant to its Open Access Transmission Tariff ("OATT"). Under the LG&E Arrangements, LEM paid Big Rivers a minimum $5 million annually for transmission service.

Unwind of LG&E Arrangements

In March 2007, Big Rivers executed a Transaction Termination Agreement (the "Termination Agreement") among LEM, WKEC and Big Rivers setting forth the term and conditions upon which the Company and E.ON agreed to terminate the LG&E Arrangements (the "Unwind"). Protracted negotiations with creditors, governmental agencies, the Smelters and others followed the execution of the Termination Agreement. The closing of the Unwind took place on July 16, 2009.

Summary of Major Provisions of Unwind

In connection with the closing of the Unwind, E.ON compensated Big Rivers with approximately $864.6 million of value and Big Rivers took certain other actions as set forth below:

- E.ON made a cash payment to the Company of approximately $506.7 million. This amount represented (1) a termination payment by WKEC to the Company to compensate it for the risks associated with assuming responsibility for the operation of the Company's owned generating facilities and Station Two and (2) the netted amount of various payment obligations by both WKEC and the Company contemplated by the Termination Agreement.

- WKEC waived the requirement in the LG&E Arrangements that the Company make a payment at the expiration or early termination of the LG&E Arrangements in respect of the residual value of WKEC's capital contributions to the Company's owned generating facilities and Station Two. Additionally, WKEC conveyed to the Company certain utility plant assets used in connection with the operation of the Company's owned generating plants previously leased to WKEC. The value of these items was approximately $188.0 million.

- The Company 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 and Rural Economic Reserve accounts were established to help the Company cushion the effect of any potential future rate increases for fuel, environmental, and purchase power expenses on its rates to the Members for service to their non-Smelter members. The Transition Reserve account was established as a financial reserve account that would help the Company mitigate financial costs, if any, associated with the termination of the Smelter Agreements by a Smelter. In 2011 Big Rivers used the $35 million from the Transition Reserve to prepay a portion of its Rural Utilities Service ("RUS") related debt and Big Rivers will use a portion of the proceeds of a bank loan to replenish the Transition Reserve. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS – Executive Overview."

- WKEC conveyed to the Company a flue gas desulphurization ("FGD") system which had recently been constructed at the Company's Kenneth C. Coleman Plant (the "Coleman Plant"). The value ascribed to the flue gas desulphurization facility was approximately $98.5 million.

- WKEC conveyed to the Company personal property and inventories of coal, petroleum coke, fuel oil, lime, limestone and spare parts, and materials and supplies. The value of these items was approximately $55.0 million.

- WKEC forgave a promissory note of approximately $15.4 million the Company owed to LEM.

- WKEC conveyed to the Company 14,000 sulfur dioxide ("SO_2") allowances allotted by the United States Environmental Protection Agency ("EPA") with a fair market value of approximately $1.0 million on July 16, 2009.

- The lease of the generating facilities to WKEC and all the other property interests of WKEC and LEM in the generating facilities previously leased to WKEC were terminated.

- The Station Two Agreement was terminated and the Company resumed its responsibility to operate Station Two and to purchase the output of Station Two in excess of the City's requirements in accordance with the Station Two Power Sales Contract.

Change in Capital Structure Resulting from Unwind

On July 16, 2009, the Company prepaid $140.2 million of the indebtedness it owed to the RUS and the schedule of maximum permitted outstanding balances on the amortizing debt the Company owed to the RUS was adjusted. The non-interest bearing RUS Series B Note was also restructured in concert with the Unwind into a single "bullet" payment due December 31, 2023. The Company's debt to RUS was incurred primarily to finance its generating assets. In connection with the Unwind the Company obligated itself to reduce the maximum permitted outstanding balances of its RUS debt by $60.0 million by October 1, 2012 and $200.0 million by January 1, 2016. The Company is using the proceeds of certain bank loans to satisfy these obligations. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS – Executive Overview."

The chart set forth below shows the impact of the Unwind on the Company's outstanding debt.

Debt Instrument	Pre-Unwind Balance	Unwind Close Transaction	Post-Unwind Balance
		(In millions of dollars)	
RUS Series A Note	$ 740 0	$140 2[1]	$599.8
RUS Series B Note	106 5	0.0	106 5
LEM Settlement Note	15 4	15 4[2]	0 0
PMCC Note	12 4	12 4[3]	0 0
County of Ohio, Kentucky, promissory note (1983 Series) 1983 Series Pollution Control Bonds	58 8	0.0	58.8
County of Ohio, Kentucky, promissory note (2001A Series) 2001A Series Pollution Control Bonds	83.3	0 0	83.3
	$1,016.4	$168.0	$848.4

(1) Big Rivers payment to RUS on Unwind closing date
(2) Forgiveness of debt by E ON
(3) Big Rivers payment to Philip Morris Capital Corporation on Unwind closing date

As a result of the Unwind, the Company went from an equity to total capitalization ratio of -19% as of December 31, 2008, to 35.3% as of December 31, 2011.

Resumption of Operational Responsibilities in Connection with Generating Facilities

In connection with the Unwind, the lease of the Company generating facilities to WKEC was terminated and the Company resumed responsibility for the operation of its generating facilities. Thus, the Company assumed responsibility for the risks associated with such operation (e.g. fuel, capital costs associated with change in law). The Company intends to use the output of its generating facilities to supply the needs of the Members, including approximately 850 MW of power that is necessary for Kenergy to supply its contractual obligations to the Smelters, which were primarily serviced by LEM prior to the Unwind. See "THE SMELTER AGREEMENTS" and APPENDIX D – "SUMMARY OF CERTAIN PROVISIONS OF THE SMELTER AGREEMENTS." Power and energy generated above the Members' requirements will be sold into the wholesale power market.

Wholesale Power Contracts with Members

Each of Meade, Jackson Purchase and Kenergy is party to a wholesale power contract with Big Rivers (the "All Requirements Contracts") providing that Big Rivers sells and delivers to the Member, and the Member purchase and receive from Big Rivers, all the electric power and energy which the Member requires for the operation of the Member's system (except Kenergy's requirements for the Smelters) to the extent that Big Rivers has power and energy and facilities available. The term of each All Requirements Contract extends through December 31, 2043 and neither of the parties may unilaterally terminate the contract, without cause, prior to such date. Each All Requirements Contract may be terminated by either party thereto after December 31, 2043, upon six months' notice.

The All Requirements Contracts require each Member to pay the Company monthly for capacity and energy furnished. The All Requirements Contracts provide that if a Member fails to pay any bill by the first business day following the twenty-fourth day of the month, the Company may, upon five (5) business days' written notice, discontinue delivery of electric power and energy. The All Requirements Contracts also provide that, so long as any notes and note guarantees are outstanding from the Company to the RUS, the Member may not reorganize, dissolve, consolidate, merge, or sell, lease or transfer all or a substantial portion of its assets unless it has either (i) obtained the Company's written consent and the written consent of the RUS, or (ii) paid a portion of the outstanding indebtedness on the notes and the Company's other commitments and obligations then outstanding, such portion to be determined by the Company with RUS approval. The All Requirements Contracts may only be amended with the approval of the RUS and upon compliance with such other reasonable terms and conditions as the Company and RUS may agree.

Each Member is required to pay the Company for capacity and energy furnished under its All Requirements Contract in accordance with the Company's established rates as approved by the Kentucky Public Service Commission ("KPSC"). All Requirements Contracts with the Members provide that the Company's board of directors (the "Board of Directors") establish rates to produce revenue sufficient, but only sufficient, together with all of the Company's other revenue, to pay the cost of operation and maintenance of all of the Company's generation, transmission and related facilities, to pay the cost of capacity and energy purchased by the Company for resale, to pay the cost of transmission service, to pay the principal of and interest on all the Company's indebtedness and to provide for the establishment and maintenance of reasonable financial reserves.

The All Requirements Contracts require the Company's Board of Directors to review the rates at least annually and to revise such rates as necessary to produce revenue as described above. Big Rivers must give Members no less than thirty (30) days' or more than forty-five (45) days' written notice of every rate revision. The Company's electric rate revisions are subject to the approval of the RUS and the KPSC, after which the Members are permitted to incorporate such rate changes into their own rate structures. See "RATE AND ENVIRONMENTAL REGULATION – Kentucky Rate Regulation" for information relating to rate regulation by the KPSC.

Smelter Agreements with Kenergy

In addition to the All Requirements Contracts, Big Rivers and Kenergy are parties to two wholesale electric service agreements under which the Company provides a fixed amount of power and energy of 850 MW that is necessary for Kenergy to supply its contractual obligations to the Smelters through December 31, 2023. These agreements are exceptions to the "all requirements" obligations in the All Requirements Contracts with Kenergy. See "THE SMELTER AGREEMENTS" and APPENDIX D – "SUMMARY OF CERTAIN PROVISIONS OF THE SMELTER AGREEMENTS."

Existing Generation and Transmission Resources

The Company owns interests in seven base load coal-fired generating units and one oil- or natural gas-fired combustion turbine generating unit, all of which are in commercial operation. These units provide the Company with approximately 1,444 MW of capacity. See "GENERATION AND TRANSMISSION ASSETS – Generation Resources" for a discussion of the Company's existing generation facilities. The Company also has a variety of purchase arrangements, including the Station Two Power Sales Contract with the City of Henderson and a contract with (the "SEPA Contract") the Southeastern Power Administration ("SEPA"), which together supply the Company with up to 375 MW of power. The Company purchases 197 MW from HMP&L pursuant to the Station Two Power Purchase Agreement and up to 178 MW under the SEPA Contract. The Company normally uses its entitlement under the SEPA Contract for peaking; however, as a result of problems with certain dams on the Cumberland River hydro system, the Company's capacity entitlement has been suspended and the Company currently is receiving only energy. See "GENERATION AND TRANSMISSION ASSETS – Other Power Supply Resources" for a discussion of the Company's power purchase arrangements. The Company also owns 1,266 miles of transmission lines and 22 substations and has additional access to approximately 100 MW of firm transmission service through an agreement with another utility. The Company is a participant in the Midwest Independent System Operator, Inc. ("MISO"). MISO is a non-profit regional transmission organization operating in 13 states in the Midwest United States and Manitoba, Canada. MISO has functional control of the operation of its participants transmission facilities of 100 kilovolts ("kV"). In addition to operating the bulk transmission system of its participants, MISO also operates the Midwest Market (the "MISO Market"). In the MISO Market, the Company and other participants submit day-ahead or real-time bids and offers for the purchase or sale of energy at various locations. MISO then directs each MISO Market participant whether to operate its generation facilities and determines the price of energy at each location for a particular time period.

SELECTED FINANCIAL DATA

The following financial data present selected information relating to the Company's financial condition and results of operations. The Balance Sheet data as of December 31, 2011 and 2010 and the Statement of Revenues and Expenses data for years ended December 31, 2011, 2010 and 2009 were derived from the Company's audited financial statements included in APPENDIX A. The Balance Sheet data as of December 31, 2009 and the Statement of Revenues and Expenses data for the years ended December 31, 2008 and 2007 were derived from the Company's audited financial statements for those years. The information shown below should be read in conjunction with the financial statements and the related notes thereto in Appendix A. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS."

BIG RIVERS
STATEMENT OF REVENUES AND EXPENSES
(dollars in thousands)

	Year Ended December 31, (Audited)				
	2011	2010	2009	2008	2007
Operating revenues.					
Member tariff electric energy revenues	$456,351	$432,100	$259,579	$114,513	$113,281
Other electric energy revenues	102,021[1]	82,390	67,151	90,006	148,611
Lease revenue	---	---	32,027	58,423	58,265
Other operating revenues	3,617	12,834	14,603	10,239	9,713
Total operating revenues	561,989	527,324	373,360	273,181	329,870
Operating expenses:					
Operations:					
Fuel for electric generation	226,229	207,749	80,655	---	---
Power purchased and interchanged	112,262	99,421	116,883	114,643	169,768
Production, excluding fuel	50,410	52,507	22,381	---	---
Transmission and other	39,085	35,273	35,444	28,600	27,196
Maintenance	47,718	46,880	29,820	4,258	4,240
Depreciation and amortization	35,407	34,242	32,485	31,041	30,632
Total operating expenses	511,111	476,072	317,668	178,542	231,836
Electric operating margins	50,878	51,252	55,692	94,639	98,034
Interest expense and other.					
Interest, net of capitalized interest	45,226	46,570	59,898	65,719	60,932
Interest on obligations related to long-term lease	---	---	---	6,991	9,919
Amort of loss from termination of lease	---	---	2,172	811	---
Income tax expense	100	259	1,025	5,934	---
Other, net	220	166	112	123	103
Total interest expense and other	45,546	46,995	63,207	79,578	70,954
Operating margin before non-operating margin	5,332	4,257	(7,515)	15,061	27,080
Non-operating margin.					
Interest income on restricted investments under long-term lease	---	---	---	8,742	12,481
Gain on "Unwind" Transaction	---	---	537,978	---	---
Interest income and other	268	2,734	867	4,013	7,616
Total non-operating margin	268	2,734	538,845	12,755	20,097
Net margin	$5,600	$6,991	$531,330	$ 27,816	$ 47,177

[1] Includes Domtar cogenerator backup power revenues.

BALANCE SHEET
(dollars in thousands)

	December 31, (Audited)		
	2011	**2010**	**2009**
Assets:			
Utility plant, net	$1,092,063	$1,091,566	$1,078,274
Restricted investments under long-term lease	–	–	–
Restricted Investments – Member rate mitigation	163,162	217,562	243,225
Other deposits and investments, at cost	5,911	5,473	5,342
Current Assets:			
Cash and cash equivalents	44,849	44,780	60,290
Accounts receivable	44,287	45,905	47,493
Fuel inventory	33,894	37,328	37,830
Non-fuel inventory	25,295	23,218	20,412
Prepaid expenses	4,217	2,502	3,233
Total current assets	152,542	153,733	169,258
Deferred loss–termination of sale-leaseback	–	–	–
Deferred charges and other	4,244	3,851	9,384
Total assets	$1,417,922	$1,472,185	$1,505,483
Equities (Deficit) and Liabilities:			
Capitalization:			
Equities (deficit)	$389,820	$386,575	$379,392
Long-term debt	714,254	809,623	834,367
Total capitalization	1,104,074	1,196,198	1,213,759
Current liabilities:			
Current maturities of long-term debt and obligations	72,145[2]	7,373	14,185
Notes payable	–	10,000	–
Purchased power payable	1,878	1,516	3,362
Accounts payable	28,446	29,782	30,657
Accrued expenses	10,380	10,627	9,864
Accrued interest	9,899	11,134	9,097
Total current liabilities	122,748	70,432	67,165
Deferred credits and other:			
Regulatory liabilities – Member rate mitigation	169,001	185,893	207,348
Other	22,099	19,662	17,211
Total deferred credits and other	191,100	205,555	224,559
Total equities and liabilities	$1,417,922	$1,472,185	$1,505,483

[2] Includes $60 million due to the RUS by October 1, 2012, that the Company intends to refinance with the proceeds of certain bank loans.

CAPITALIZATION

The Company's capitalization derived from the financial statements included in APPENDIX A is as follows:

	December 31, (Audited) 2011
	(in thousands)
Long-Term debt:	
Secured by the Mortgage Indenture:	
RUS Series A Note	$521,250
RUS Series B Note	123,049
1983 Series Pollution Control Bonds	58,800
2001A Series Pollution Control Bonds	83,300
Total long-term debt	$786,399
Less: current portion	72,145[3]
Total long-term debt, excluding current portion	714,254
Equity:	
Accumulated Margins	397,098
Other Equities and Accumulated Other Comprehensive Income	(7,278)
Total Equities	$389,820
	$1,104,074
Total capitalization	

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[3] Includes $60 million due to the RUS by October 1, 2012, that the Company intends to refinance with the proceeds of certain bank loans.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Caution Regarding Forward Looking Statements

This Disclosure Statement contains forward-looking statements regarding matters that could have an impact on the Company's business, financial condition and future operations. These include statements regarding expected capital expenditures, sales to Members, and liquidity and capital resources. Some forward-looking statements can be identified by use of terms such as "may," "will," "expects," "anticipates," "believes," "intends," "projects," "plans," or similar terms. These forward-looking statements, based on the Company's expectations and estimates, are not guarantees of future performance and are subject to risks, uncertainties, and other factors that could cause actual events or results to differ materially from those expressed in these statements. These risks, uncertainties, and other factors include, but are not limited to, general business conditions, changes in demand for power, federal and state legislative and regulatory actions and legal and administrative proceedings, changes in and compliance with environmental laws and policies, weather conditions, the cost of commodities used in Big Rivers' industry and unanticipated changes in operating expenses, capital expenditures and tax liabilities. Some of the factors that could cause the Company's actual results to differ from those anticipated by these forward-looking statements are described under the caption "RATE AND ENVIRONMENTAL REGULATIONS." Any forward-looking statement speaks only as of the date on which the statement is made, and the Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which the statement is made even if new information becomes available or other events occur in the future.

Executive Overview

Under the Unwind, the Company obligated itself to reduce the maximum permitted balances of its RUS Series A Note by $60.0 million on October 1, 2012 and $200.0 million on January 1, 2016. The Company expects to meet these obligations through the issuance of long-term debt. The Company also has significant projected capital expenditures including approximately $283.5 million in pollution control expenditures in order to keep its coal-fired units in compliance with various EPA standards. Big Rivers sought KPSC approval for its 2012 environmental compliance plan ("ECP") in an April 2012 filing. Big Rivers expects to finance the costs of the ECP using an unsecured line of credit as bridge financing to permanent, long-term financing. The Company also has a $50.0 million unsecured revolving credit agreement with CoBank ACB ("CoBank") that expires July 16, 2012, that it is seeking to renew for a five year term as described below.

The Company has entered into letters of intent with CoBank and the National Rural Utilities Cooperative Finance Corporation ("CFC"). Big Rivers will borrow $235 million from CoBank in the form of a secured term loan. Also, Big Rivers will enter into an unsecured revolving credit agreement with CoBank to replace its current revolving credit agreement with CoBank. Big Rivers will borrow $302 million from CFC under a secured term loan. On July 2, 2012 Big Rivers borrowed $25 million under the existing CFC revolving credit agreement and prepaid that amount on the RUS Series A Note. Big Rivers plans to repay this borrowing in connection with the closing of the bank loans. The proceeds of both the CFC and the CoBank loans will be used primarily to prepay a portion of the RUS Series A Note. It is expected that the application of the prepayment, together with the use of a portion of the proceeds of the CFC and the CoBank loans will result in the reduction of the maximum debt balance on the RUS Series A Note from $561.6 million to $84.6 million. A portion of the CoBank loan will also be used to replenish the Transition Reserve investment account in the amount of $35 million. Big Rivers expects to use a combination of loan proceeds, cash flows from operations, secured debt offerings in the public debt market and/or loans from the Federal Financing Bank ("FFB") guaranteed by RUS to finance its operating costs and its capital expenditures, including the ECP, through 2015.

On March 28, 2012, Big Rivers filed an application to the KPSC seeking approval to issue both secured and unsecured debt in connection with the CoBank and the CFC loans. The application was approved May 25, 2012, and Big Rivers plans to close the loans July 27, 2012. Since the closing is not scheduled until later this month, the Company and CoBank have extended the term of the expiring CoBank revolving credit agreement for a period of six months.

The Company is currently forecasting a MFI Ratio (as defined herein under the caption "Cooperative Operations – Coverage Ratio") of 1.10 for 2012, as required by the Indenture dated as of July 1, 2009, as supplemented and amended (the "Mortgage Indenture"), which MFI Ratio will result in net margins of $4.5 million. During the year ended December 31, 2011, Big Rivers achieved net margins of approximately $5.6 million and the MFI Ratio was 1.12.

Critical Accounting Policies

General

The Company prepares its financial statements in conformity with accounting principles generally accepted in the United States. Management exercises judgment in the selection and application of these principles, including making certain estimates and assumptions that impact the Company's results of operations and the amount of its total assets and liabilities reported in the Company's financial statements. The Company considers critical accounting policies to be those policies that, when applied by management under a particular set of assumptions or conditions, could materially impact the Company's financial results if such assumptions or conditions were different than those considered by management. Set forth below are certain accounting policies that are considered by management to be critical and to possibly involve significant risk, which means that they typically require difficult, subjective or complex judgments, often as a result of the need to make estimates about the effect of matters that are inherently uncertain. Other significant accounting policies and recently issued accounting standards are discussed in Note One – "Significant Accounting Policies" of Notes to Financial Statements in APPENDIX A.

Use of Accounting Policies and Estimates

The application of accounting policies and estimates is a continuing process. As the Company's operations change and accounting guidance evolve, its accounting policies and estimates may be revised. The Company has identified a number of critical accounting policies and estimates that require significant judgments. The Company bases its judgments and estimates on experience and various other assumptions that the Company believes are reasonable at the time of application. The Company's judgments and estimates may change as time passes and more information about the environment in which it operates becomes available. If actual results are different than the estimated amounts recorded, adjustments are made taking the new information into consideration. The Company discusses its critical accounting policies, significant estimates and other certain accounting policies with the Board of Directors, as appropriate. The Company's critical accounting policies and significant estimates are discussed below.

Regulatory Accounting

The Company's accrual basis accounting policies follow the Uniform System of Accounts as prescribed by RUS Bulletin 1767B-1, as adopted by the KPSC. These regulatory agencies retain authority over the Company and periodically issue orders and instructions on various accounting and ratemaking matters. The Company's operations meet the criteria for application of regulatory accounting treatment. As a result, the Company records approved regulatory assets and liabilities that result from the regulated ratemaking process that would not ordinarily be recorded under Generally Accepted Accounting Principles. The Company had no Regulatory Assets at December 31, 2011 and the Company's Regulatory Liabilities were $169.0 million. Regulatory assets generally represent incurred costs that have been deferred because such costs are probable of future recovery in Member rates. Regulatory liabilities generally represent amounts established by the Company's regulator to mitigate the net effect on the Members of fuel and environmental surcharges and surcredits. These amounts are recorded in revenue as the underlying fuel and environmental costs are incurred. The Company continually assesses whether any regulatory account it has is probable of future recovery or refund by considering factors such as applicable regulatory environment changes, historical regulatory treatment for similar costs, recent rate orders to other regulated entities and the status of any pending or potential legislation. Based on this continual assessment, the Company believes its existing regulatory liabilities are probable of future refund. This assessment reflects the current political and regulatory climate at the state level, and is subject to change in the future. If future recovery of a regulatory asset or refund of a regulatory liability ceases to be probable, the asset or liability write-off would be recognized in operating income.

Revenue Recognition

Revenues on sales of electricity are recognized as earned when the electricity is provided. Revenues under the wholesale power contracts for sales to Members including the Smelter Agreements are based on month-end meter readings and billed the month following the month of service.

Off-Balance Sheet Arrangements

The Company had no off-balance sheet arrangements as of December 31, 2011.

Accounting for Loss Contingencies

The Company is involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of its financial statements, the Company makes judgments regarding the future outcome of contingent events and records a loss contingency when it is determined that it is probable that a loss has occurred and the amount of the loss can be reasonably estimated. The Company regularly reviews current information available to determine whether any such accruals should be adjusted and whether new accruals are required. Contingent liabilities are often resolved over long periods of time. Amounts recorded in the financial statements may differ from the actual outcome once the contingency is resolved, which could have a material impact on the Company's future operating results, financial position or cash flows. The Company had no contingent matters requiring accrual at December 31, 2011.

Depreciation of Utility Plant

Utility plant is recorded at original cost. Replacements of depreciable property units are also charged to utility plant. Replacements of minor items of property are charged to maintenance expense. The Company performed a depreciation study in 1998 that resulted in depreciation rates based on extended remaining service lives. Depreciation of utility plant is recorded using the straight-line method and rates based on the estimated remaining years of service determined by such study. This study, which significantly reduced depreciation expenses, was approved by the KPSC and the RUS in 1998 and made effective as of July 1, 1998. These depreciation rates remained in effect up to December 1, 2011.

On March 1, 2011, the Company filed a new depreciation study with the KPSC as part of a request for approval of an increase in member rates. The new depreciation study, which was approved by the KPSC in its order dated November 17, 2011, resulted in an 11% increase in depreciation expense and became effective December 1, 2011.

Accounting for Income Taxes

The Company was formed in 1961 as a tax exempt cooperative under section 501(c)(12) of the Internal Revenue Code. To retain exempt status, at least 85% of the Company's receipts must be generated from transactions with the Members. In 1983, sales to Members did not meet the 85% requirement due to sales to Non-Members. Since 1983, the Internal Revenue Service ("IRS") considers the Company a taxable organization. Beginning with 2010, post-Unwind, the Company believes that its sales to Members satisfy the 85% requirement and the Company now could qualify for exempt status. In order to qualify for exempt status the Company would need to apply to the IRS. The Company has no current intentions of applying for exempt status. The Company is also subject to Kentucky income tax.

Deferred tax assets and liabilities are recognized for the future tax consequences attributable to temporary differences between the book basis and tax basis of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to reverse, be recovered or be settled. The probability of realizing deferred tax assets in the future is based on forecasts of future taxable income and the use of tax planning that could impact the Company's ability to realize deferred tax assets. If future utilization of deferred tax assets is uncertain, a valuation allowance may be recorded against them.

In assessing the likelihood of realization of its deferred tax assets, the Company considers estimates of the amount and character, patronage or non-patronage, of future taxable income. Actual income taxes could vary from estimated amounts due to the impacts of various items, including changes in income tax laws, the Company's forecasted financial condition and results of operations in future periods, as well as results of audits and examinations of filed tax returns by taxing authorities. Although the Company believes its assessment of its income tax estimates are reasonable, actual results could differ from the estimates.

At December 31, 2011, the Company reported deferred tax assets of $53.9 million, of which $12.8 million related to net operating losses and $19.7 million related to the RUS Series B Note. At December 31, 2011, accrued net operating losses totaled $32.4 million, expiring at various times between years 2011 and 2031. Additionally, at December 31, 2011, the Company reported deferred tax liabilities of $9 thousand resulting from pollution control bond refunding costs.

Pension and Other Postretirement Benefits

The Company has noncontributory defined benefit pension plans covering approximately 100 of its 627 member work force. The salaried employees defined benefit pension plan was closed to new entrants effective January 1, 2008, and the bargaining employees defined benefit pension plan was closed to new hires effective November 1, 2008. For those not covered in the defined benefit plans, the Company established base contribution accounts in the defined contribution thrift and 401(k) savings plans, which were renamed the retirement savings plans. The base contribution account is funded by employer contributions based on graduated percentages of the employee's pay, depending on age.

The Company also provides certain postretirement medical benefits for retired employees and their spouses. Generally, except for retirees who were part of the generation union, the Company pays 85% of the premium cost for all retirees age 62 to age 65. It pays 25% of the premium cost for spouses under age 62. For salaried retirees age 55 to age 62, the Company pays 25% of the premium cost. Beginning at age 65, the Company pays 25% of the premium cost if the retiree is enrolled in Medicare Part B. For each generation bargaining retiree, the Company establishes a retiree medical account at retirement equal to $1,200 per year of service up to 30 years ($1,250 per year for those retiring on or after January 1, 2012). The account balance is credited with interest based on the 10-year Treasury Rate subject to a minimum of 4% and a maximum of 7%. The account is to be used for the sole purpose of paying 100% of the premium cost for the retiree and spouse.

The calculations of defined benefit pension expenses, other postretirement benefit expenses, and pension and other postretirement benefit liabilities, require the use of assumptions. Changes in these assumptions can result in different expenses and reported liability amounts, and future actual experience can differ from the assumptions. The Company believes the most critical assumptions are the expected long-term rate of return on plan assets and the assumed discount rate. Additionally, medical and prescription drug cost trend rate assumptions are critical in estimating other postretirement benefits.

Funding requirements for defined benefit pension plans are determined by government regulations. The Company's defined benefit pension plans are fully funded for the purposes of the Employee Retirement Income Security Act of 1974, as amended ("ERISA"), and the Company has made additional voluntary contributions. At December 31, 2011, for the defined benefit pension plans, the fair value of plan assets exceeded the present value of the accumulated benefit obligation by $2.5 million. The Company funds it's other postretirement benefit plan obligations on a pay-as-you-go basis, on a cash basis as benefits are paid. No assets have been segregated and restricted to provide for the other postretirement benefits. At December 31, 2011, the present value of the projected benefit obligation for the other postretirement benefit plans was $18.0 million.

Cooperative Operations

Utility Margins

The Company operates its electric business on a not-for-profit basis and, accordingly, seeks to generate revenue sufficient to recover its cost of service and produce net margins sufficient to establish reasonable financial reserves, meet financial coverage requirements and accumulate additional equity as determined by the Board of Directors. Revenue in excess of expenses in any year is designated as net margins in the Company's Statements of Operations. The Company designates retained net margins in its Balance Sheets as patronage capital which it assigns to each of its patrons, including the Members, on the basis of its business with the Company. Any distributions of patronage capital are subject to the discretion of the Board of Directors and restrictions contained in the Mortgage Indenture. See APPENDIX C – "SUMMARY OF CERTAIN PROVISIONS OF THE MORTGAGE INDENTURE – Covenants."

Rate Structure

Under the wholesale power contracts, the Members pay the Company for all power and energy supplied at rates approved by the KPSC. The rates to all Members are bundled and include rates for capacity (also referred to as demand), energy, transmission, ancillary service and other special rates. In addition to the demand and energy rates, the Company has a fuel adjustment clause, an environmental surcharge clause, and a purchased power adjustment clause for purchased power not recovered in the fuel adjustment clause above a base amount under which it can increase or decrease charges to the Members based on the variance between the Company's actual cost and the cost included in its base rates. See APPENDIX D – "SUMMARY OF CERTAIN PROVISIONS OF THE SMELTER AGREEMENTS."

Coverage Ratio

Subject to any necessary regulatory approvals, such as KPSC approval and RUS approval, if required, the Mortgage Indenture requires the Company to establish and collect rates for the use or the sale of the output, capacity or service of its electric generation and transmission system which are reasonably expected to yield margins for interest, for the twelve-month period commencing with the effective date of the rates, equal to at least 1.10 times total interest charges on debt secured under the Mortgage Indenture during that twelve-month period (the "MFI Ratio"). The MFI Ratio is calculated by dividing the Margins for Interest for a period by the Interest Charges for such period. For the definition of "Margins for Interest" and "Interest Charges" see APPENDIX C – "SUMMARY OF CERTAIN PROVISIONS OF THE MORTGAGE INDENTURE – Covenants." A failure by the Company to actually achieve a 1.10 MFI Ratio will not itself constitute an Event of Default under the Mortgage Indenture. A failure to establish Rates reasonably expected to achieve a 1.10 MFI Ratio, however, will be an Event of Default if such failure continues for 30 days after the Company receives notice thereof from either the Indenture Trustee or the holders of not less than 20% in principal amount of the outstanding Mortgage Indenture Obligations, unless such failure results from the Company's inability to obtain regulatory approval. However, in order to issue additional Obligations under the Mortgage Indenture, the Company must certify that its MFI Ratio was at least 1.10 during the immediately preceding fiscal year (or, if the certification is made within 90 days of the end of a fiscal year, the second preceding fiscal year) or during any consecutive 12-month period within the 15 month period immediately preceding the request for the issuance of additional Mortgage Indenture Obligations. The 2011 net margins were $5.6 million and the MFI Ratio was 1.12.

Results of Operations

Sales to Members

Electric sales to the Members are made pursuant to wholesale power contracts with each Member. The table below sets forth the Sales to Members in MWhs for 2011, 2010 and 2009. The Smelter sales are shown both before and after the closing of the Unwind. Before the closing of the Unwind, the Company supplied only a small portion of the Smelters' needs. Since the Unwind, the Company supplies 850 MW of the Smelters' needs. The wholesale rate to Kenergy for the Smelters averaged $44.48 per MWh for 2011, $44.05 per MWh for 2010 and $46.22 per MWh for 2009.

Rural Member sales include residential and commercial loads. The 2011 rural Member sales reflect a .11 million MWh decline or a 4.44% decrease from 2010. This decline is attributable to the mild weather in 2011. The 2010 rural member sales reflect a .24 million MWh increase or a 10.71% increase from 2009 primarily due to the hot summer weather. Industrial Member sales were relatively flat over the three year period.

Smelter sales in 2011 were .50 million MWh or 7.87% higher than 2010. The increase is primarily due to restarting an idle potline at Century. Smelter sales in 2010 were 2.88 million MWh or 83.00% higher than 2009, reflecting a full year of post-Unwind sales.

Sales to Members
(in millions of MWhr)

	2011	**2010**	**2009**
Rural Member	2.37	2.48	2.24
Industrial Member*	0.97	0.93	0.92
Smelter (Pre-Unwind)	0.00	0.00	0.58
Smelter (Post-Unwind)	6.85	6.35	2.89
	10.19	9.76	6.63

*Excludes Domtar cogeneration backup power.

Sales to Non-Members

The table below sets forth the Sales to Non-Members in megawatt-hours for 2011, 2010 and 2009. After the closing of the Unwind on July 16, 2009, the Company had access to all of the generation available from its production assets, which enabled it to sell any excess on the open market. The excess generation was sold in the market to third parties. Non-Member sales in 2011 reflect a .85 million MWh or 38.46% increase from 2010 due to a full year of MISO membership. The 2010 Non-Member sales are 1.04 million MWh or 88.89% higher than 2009, reflective of a full year of post-Unwind operations.

	Sales to Non-Members (in millions of MWhr)		
	2011	2010	2009
Non-Member	3.06	2.21	1.17

*Includes Domtar cogeneration backup power.

Other Revenue

The table below sets forth the Other Revenue for 2011, 2010 and 2009. After the closing of the Unwind on July 16, 2009, the lease payments from E.ON for the Company's generation assets were terminated, resulting in a decrease of $32.0 million in 2010. In December 2010, Big Rivers became a member of MISO. As a result, other operating revenue declined in the subsequent year. Other operating revenue in 2011 was $9.2 million or 71.82% lower than 2010 due to the first full year of MISO membership. Prior to MISO membership, other operating revenue was an equal off-set to certain related operating expenses below. Increases and decreases were due to changes in transmission revenue from the Company's internal Non-Member energy services departmental activities. Since entrance into MISO, other operating revenue provides only a partial offset to the related operating expenses.

Other Revenue
(in thousands)

	2011	2010	2009
Lease revenue	---	---	$32,027
Other operating revenue	$3,617	$12,834	14,603
	$3,617	$12,834	$46,630

Operating Expenses

The table below sets forth the Operating Expenses for 2011, 2010 and 2009. Fuel, production and maintenance expenses in 2011 were $17.2 million or 5.61% higher than in 2010. Higher fuel expense resulting from increased generation and higher fuel pricing was the primary driver. These expenses were $174.3 million or 131.18% higher in 2010 than in 2009 due to the first full year of post-Unwind operation. After the closing of the Unwind on July 16, 2009, the Company became responsible for the operating expenses for the generating fleet. The 2011 power purchased was $12.8 million or 12.92% higher than 2010 as a result of the first full year of MISO membership. The 2010 power purchased was $17.5 million or 14.94% lower than in 2009. Prior to the Unwind, the Company purchased all of its power while post-Unwind the Company primarily purchased replacement power. Transmission expenses for 2011 were $3.81 million or 10.81% higher than 2010 as a result of the first full year of membership fees due to membership in MISO. Depreciation expense increased during the last 3 years as a result of a higher capital balance being depreciated.

Operating Expenses
(in thousands)

	2011	2010	2009
Fuel for electric generation	$226,229	$207,749	$ 80,655
Power purchased and interchanged	112,262	99,421	116,883
Production, excluding fuel	50,410	52,507	22,381
Transmission and other	39,085	35,273	35,444
Maintenance	47,718	46,880	29,820
Depreciation	35,407	34,242	32,485
	$511,111	$476,072	$317,668

Interest and Other Charges

The table below sets forth Interest and Other Charges for 2011, 2010 and 2009. The Company paid RUS $140.2 million at closing of the Unwind, which served to decrease the Company's interest expense going forward. The Company continued to make debt service payments in 2010 and 2011, including utilizing the $35 million from the Transition Reserve to prepay the RUS Series A Note in 2011.

Interest and Other Charges
(in thousands)

	2011	2010	2009
Interest, net of capitalized interest	$45,226	$46,570	$59,898
Amort. of loss from termination of lease	-	-	2,172
Income tax expense	100	259	1,025
Other, net	220	166	112
	$45,546	$46,995	$63,207

Operating Margin

The table below sets forth the Operating Margin for 2011, 2010 and 2009. Operating Margin for 2011 was $1.1 million or 25.25% higher than 2010. During 2011 the KPSC issued an order approving an increase in Member base electric rates resulting in a 6.19% increase in total Member revenue. The increase was effective as of September 1, 2011. During 2011 Big Rivers also completed its first full year of membership with MISO. The MISO administration fees largely offset the increase in net sales margin in 2011. Operating Margin for 2010 was $11.8 million higher than 2009. After the closing of the Unwind on July 16, 2009, a major 8.5 week planned outage for the D.B. Wilson Unit No. 1 Plant ("Wilson Plant")was completed in the fall. This expense, coupled with lower Member sales due to the weather, resulted in the lower operating margin in 2009 versus 2010.

Operating Margin
(in thousands)

	2011	2010	2009
Operating Margin	$5,332	$4,257	$(7,515)

Non-Operating Margin

The table below sets forth the amount of Non-Operating Margins for 2011, 2010 and 2009. The Non-Operating Margin in 2011 included interest income and patronage allocations. In addition to interest income and patronage allocations, the Non-Operating Margin in 2010 also included a write-off of the reserve for obsolescence that was established for certain materials and supplies inventory upon the Unwind closing. The Non-Operating Margin in 2009 resulted predominantly from the closing of the Unwind.

Non-Operating Margin
(in thousands)

	2011	2010	2009
Gain on Unwind	-	-	$537,978
Interest income and other	268	$2,734	867
	$268	$2,734	$538,845

Net Margin

The 2011 net margin was $1.4 million or 19.90% lower than 2010. Three items account for the majority of the decline in 2011 net margin. First, 2011 reflects an additional expense of $4.6 million related to a full year of MISO membership fees. Second, following a thorough analysis during 2010, the balance of the reserve for obsolescence that was established for certain materials and supplies inventory upon the Unwind closing was written off, resulting in a positive impact of $1.9 million to the 2010 net margin. Third, largely offsetting the unfavorable expense variance is a $5.0 million increase in net sales margin (electric sales revenue less variable cost) in 2011. This is principally due to the Member rate increase and higher Smelter and off-system sales volumes in 2011, largely offset by lower market pricing in off-system sales.

The 2010 net margin was $524.3 or 98.68% lower than 2009. While the 2009 net margin was $531.3 million, when the one-time $538 million Unwind gain is excluded, 2009 reflected a $6.6 million loss. There are three items that explain the majority of the $13.6 million net improvement, excluding Unwind gain, in the 2010 net margin. First, interest expense reflected a $16.2 million favorable variance, primarily due to a $222.1 million reduction in long-term debt since 2008. Second, the balance of the reserve for obsolescence that was previously discussed was written off, resulting in a non-operating margin of $1.9 million. Third, electric operating margin reflected a $4.4 million unfavorable variance for the first full year of post-Unwind operations, principally due to a depressed market price for off-system sales.

Net Margin
(in thousands)

	2011	2010	2009
Net Margin	$5,600	$6,991	$531,330

Financial Condition

As of December 31, 2011 compared to December 31, 2010

The Company's total assets decreased $54.3 million, to $1,417.9 million as of December 31, 2011, from $1,472.2 million as of December 31, 2010. The primary reasons are that in 2011 Big Rivers used $35 million from the Transition Reserve to prepay a portion of its RUS Series A Note, and the continuing use of the Economic Reserve to mitigate the non-smelter member rate impact stemming from the fuel adjustment clause and the environmental surcharge. Regarding long-term debt, a $60 million bullet payment on the RUS Series A Note is due by October 1, 2012 and was reclassified from long-term debt to current maturities in the balance sheet. As a result, working capital at December 31, 2011, decreased $53.5 million and long-term obligations decreased by $95.3 million from 2010 primarily due to the debt prepayment and current maturities. The Company will refinance the payment relating to the RUS Series A Note with the proceeds of a bank loan.

Operating revenues for the year ended December 31, 2011, were $34.7 million higher than the year ended December 31, 2010, as a result of a combination of off-system sales, Century restarting a potline, and the Member base rate increase effective September 1, 2011. Operating expenses for 2011 increased to $511.1 as compared to $476.1 in 2010. Additional fuel expenses resulting from increased generation and higher fuel pricing was the primary driver. Net margins were $5.6 million in 2011, a $1.4 million decline from 2010 primarily due to a full year of MISO membership fees, largely offset by the improved net sales margin (electric sales revenues less variable costs) resulting from the Member base rate increase.

As of December 31, 2010 compared to December 31, 2009

The Company's total assets decreased to $1,472.2 million as of December 31, 2010, from $1,505.5 million as of December 31, 2009, reflecting a voluntary prepayment of $23.9 million in 2010 on the RUS Series A Note, which the Company has since clawed back by avoiding quarterly debt service payments. As a result, working capital at December 31, 2010, decreased $18.8 million and long-term obligations decreased by $24.8 million from 2009.

Operating revenues for the year ended December 31, 2010, were $153.9 million higher than the year ended December 31, 2009, as a result of the first full year of operation after the Unwind. Operating expenses for 2010 increased to $476.1 as compared to $317.7 in 2009, also the result of the first full year of operation after the Unwind. Net margins were $7.0 million in 2010, a $524.3 million decline from 2009 resulting from the $538 million gain recorded in 2009 due to the July 16, 2009, Unwind closing.

As of December 31, 2009 compared to December 31, 2008

The Company's total assets increased to $1,505.5 million as of December 31, 2009, from $1,074.4 million as of December 31, 2008, reflecting cash and other compensation it received in connection with the Unwind. Working capital at December 31, 2009 increased $119.6 million from that of 2008 as a result of the Unwind. The Company's long-term obligations decreased by $153.0 million primarily reflecting the payment of $140.2 million on its 5.75% RUS Series A Note on the closing date of the Unwind. The Company's equity increased to $379.4 million as of December 31, 2009, from $(154.6) million as of December 31, 2008, again reflecting compensation to the Company in connection with the Unwind.

Operating revenues for the year ended December 31, 2009 were $373.4 million as compared to $273.2 million for the year ended December 31, 2008 as a result of the increase in sales to the Smelters after the Unwind Operating expenses for 2009 increased to $317.7 million as compared to $178.5 million in 2008 as a result of increases in fuel, production, transmission and maintenance expenses after the Unwind. Net margins were $531.3 million in 2009 compared to $27.8 million in 2008, primarily a result of the Unwind.

Liquidity and Capital Resources

At December 31, 2011, the Company held cash and cash equivalents of approximately $44.8 million. The Company expects to rely upon its cash flows from operations and existing cash and cash equivalents, revolving credit agreements, and loan proceeds to fund its operating costs and capital requirements during 2012.

In July 2009, the Company entered into a three year, $50.0 million unsecured revolving credit agreement with CoBank. The CoBank credit agreement may be used for capital expenditures and general corporate purposes. On April 30, 2012, the Company had no outstanding amount under the CoBank credit agreement. Since the closing on its new revolving credit agreement with CoBank is not scheduled until later this month, the Company has recently extended this facility until January 16, 2013. This agreement will be replaced with a similar CoBank revolving credit agreement with a five year term discussed under "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS – Executive Overview."

In July 2009, the Company entered into a five year, $50.0 million unsecured revolving credit facility with CFC. The CFC credit agreement may be used for capital expenditures, general corporate purposes or the issuance of letters of credit. As of April 30, 2012, letters of credit in the aggregate amount of $6.8 million were outstanding under the CFC credit agreement. The Company recently drew down $25 million under this facility and applied it to a portion of the $60.0 million reduction in the maximum permitted balances of the RUS Series A Note due on October 1, 2012. The Company plans to repay this borrowing in connection with the closing of the bank loans under "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS – Executive Overview."

Amounts available under these revolving credit facilities are accessible should there be a need for additional short-term financing. The Company expects that a combination of loan proceeds, cash flows from operations, the existing cash and cash equivalents balance, revolving credit agreements and secured debt offerings in the public debt market and/or RUS-guaranteed loans from the FFB will be sufficient to fund its operating costs and capital requirements during 2012 through 2015.

For a discussion of financing for the Company's projected capital expenditures, see "*Budgeted Capital Expenditures of Big Rivers Electric Corporation*" and "*Capital Requirements*" below.

Budgeted Capital Expenditures of Big Rivers Electric Corporation

The Company annually budgets expenditures required for additional electric generation and transmission facilities and capital for enhancement of existing facilities. The Company reviews these projections frequently in order to update its calculations to reflect changes in future plans, construction costs, market factors and other items affecting its forecasts. The actual capital expenditures could vary significantly from the budget because of unforeseen construction, changes in resource requirements, changes in actual or forecasted load growth or other issues. The Company's 2012 approved budget for capital expenditures, excluding the City's share of Station Two and capitalized interest, is $82.6 million. The Company's long range capital plan details actual and projected construction requirements and system upgrades of approximately $550.4 million, excluding the City's share of Station Two and capitalized interest, for the years 2012 through 2015 as follows:

Budgeted Capital Expenditures*

	2012	2013	2014	2015	Total
Environmental Additions	$13,894,230	$100,464,745	$130,000,000	$70,000,000	$314,358,975
Transmission	11,998,799	6,266,285	5,266,884	2,170,387	25,702,355
Generation	52,359,189	50,672,121	50,740,554	41,554,812	195,326,676
Administration	4,374,393	2,210,864	6,491,000	1,962,164	15,038,421
	$82,626,611	$159,614,015	$192,498,438	$115,687,363	$550,426,427

**Excludes the City's share of Station Two and capitalized interest.*

Some of the more significant capital investments in generation and environmental additions that are represented in the table above for each year are as follows:

For 2012, major capital investments in the budget include $13.9 million on Cross-State Air Pollution Rule ("CSAPR") and Mercury and Other Air Toxins ("MATS") related assets for environmental compliance; $4.5 million for the Robert D. Green Plant ("Green Plant") Units No. 1 and 2 FGD refurbishment project; $3.0 million for the finishing superheater project and $3.0 million for the secondary air heater project at the Wilson Plant; $2.5 million is included for the Coleman Plant Unit No. 1 hot reheat section tube replacement. Additionally, transmission expenditures include the two-way radio project budgeted for $2.8 million and the White Oak substation project for $2.5 million.;

In 2013, major capital investments in the budget include $100.5 million on continued costs related to the CSAPR and MATS projects to meet environmental standards; $2.8 million for the continuation of the White Oak substation relating to transmission; $2.8 million for continued costs on the Green Plant Units No. 1 and 2 FGD refurbishment project; $2.5 million for the Wilson Plant burner replacement project. Additionally, the Coleman Plant had 3 major projects: $2.0 million for the water treatment facility dike elevation, $2.0 million for the Coleman Unit No. 2 primary superheater and $2.5 million for the Coleman Unit No. 2 hot reheat tube replacement.

For 2014 and 2015, the major emphasis of capital spending in the budget will be the environmental projects relating to the CSAPR and MATS. Budgeted spending for these environmental projects will be $130.0 million in 2014 and $70.0 million in 2015.

Big Rivers expects to spend approximately $283.5 million from 2012 thru 2016 for projects identified in its 2012 ECP submitted to the KPSC on April 2, 2012. Major components of this plan include replacement of the FGD system at the Wilson Plant and installation of selective catalytic reduction ("SCR") equipment at Green Plant Unit No. 2.

Historically, RUS loan guarantees have provided the principal source of financing for generation and transmission cooperatives. The availability and magnitude of RUS-guaranteed loan funds are subject to annual federal budget appropriations and thus cannot be assured. Currently, RUS-guaranteed loan funds are subject to increased uncertainty because of budgetary and political pressures faced by Congress. The President's budget proposal for fiscal year 2013 provides for $6.1 billion in loans – a reduction of less than 10% from 2012 levels. Not more than $2 billion could be made available for environmental improvements to fossil-fueled generation that would reduce emissions, with the remaining funding limited to renewable energy, transmission, distribution and carbon-capture projects on generation facilities, and low emission peaking units affiliated with energy facilities that produce electricity from solar, wind and other intermittent sources of energy. Although Congress has historically rejected proposals to dramatically curtail the RUS loan program, there can be no assurance that it will continue to do so. Because of these factors, the Company cannot predict the amount or cost of RUS-guaranteed loans that may be available to it in the future. In addition, RUS has a moratorium on any loans for new base load coal or nuclear generation. The Company also seeks borrowing opportunities to issue secured debt in the public market, private and public, including tax-exempt bond financing, and borrowing from banks.

Capital Requirements

The Company expects to finance substantially all of its projected capital expenditures for the years 2012 through 2015 with a combination of loan proceeds, internally generated funds, revolving credit agreements, secured debt offerings in the capital market and/or RUS-guaranteed loans.

Debt and Lease Obligations

Big Rivers' long-term debt totaling $786.4 million as of December 31, 2011 is detailed in Note 4 (Debt and Other Long-Term Obligations) of the audited financial statements included in APPENDIX A. Outstanding debt consists of the RUS Series A Note ($521.3 million), the RUS Series B Note ($123.0 million), and two pollution control issues (totaling $142.1 million) as described below.

The Company has outstanding $58.8 million County of Ohio, Kentucky Pollution Control Refunding Bonds, Series 1983 (Big Rivers Electric Corporation Project) (the "Series 1983 Bonds"), which bear interest at a variable rate. Currently, the Series 1983 Bonds are being held as bank bonds by the liquidity provider, bearing an interest rate of 3.25%, as the remarketing agent has been unsuccessful at marketing them at the prescribed maximum rate, 120% of the variable rate index. The Company also has outstanding $83.3 million County of Ohio, Kentucky Pollution Control Refunding Revenue Bonds (Big Rivers Corporation Project), Series 2010 Bonds which bear interest at a fixed interest rate of 6% per annum.

The scheduled maturities of the Company's long-term debt at December 31, 2011 were as follows:

Payments Due by Period

	Total	2012	2013	2014	2015	Thereafter
				(in millions)		
Long-Term Debt(1)(2)	$786 4	$72.1	$79 3	$21 7	$23 0	$590.3

(1) In the operation of its business the Company has various other contracts for the purchase of electricity that are not included in the table above but are described elsewhere herein For a discussion of the Company's long-term power purchase obligations, see "GENERATION AND TRANSMISSION ASSETS – Other Power Supply Resources "

(2) Payments do not reflect the planned prepayment of the RUS Series A Note and the reduction of the maximum debt balance on such Note from $561,603,000 to $84,603,000 expected to take place on June 29, 2012

Ratings Triggers

The Company's credit ratings as of the date of this Disclosure Statement are Baa1, stable outlook, from Moody's Investor Service ("Moody's"), BBB-, stable outlook, from Fitch Ratings ("Fitch") and BBB-, stable outlook, from Standard & Poor's Credit Market Services, a division of the McGraw-Hill Companies ("S&P").

Under the loan agreement with RUS, if the Company fails to maintain two investment grade credit ratings, it must notify RUS in writing to that effect within five days after becoming aware of such failure. Next, within 30 days of the date of failing to maintain two investment grade credit ratings, the Company must, in consultation with RUS, provide a written plan satisfactory to the RUS setting forth the actions that will be taken that are reasonably expected to achieve two investment grade credit ratings. Before the Company would be impacted by this restriction, both Fitch and S&P would have to downgrade it one rating step. In the case of Moody's, its rating would have to be lowered three rating steps coupled with at least one rating downgrade from Fitch or S&P.

A change in the Company's credit rating also would have an impact on the current CoBank revolving credit agreement. This agreement contains an adjustment to the annual fees and interest rate paid on any advances based on Big Rivers' existing credit rating. An improvement in the credit rating would lower the Company's cost and a deterioration in the Company's credit rating would increase its cost under this agreement. This agreement allows the Company to utilize its highest unsecured credit rating in setting fees and interest rates. Currently, Moody's is the Company's highest secured credit rating and sets the costs under this agreement at the rating level equal to one notch lower. A one-step downgrade by Moody's would result in a .0250% increase in the unused fee and a .50% increase in the interest rate margin.

RATE AND ENVIRONMENTAL REGULATIONS

General

Many aspects of the Company's business are subject to a complex set of energy, environmental and other governmental laws and regulations at the federal, state and local level.

Kentucky Rate Regulation

The KPSC regulates the Company's rates for the sale of wholesale power to the Members. Among other things, Kentucky law authorizes the KPSC to (i) approve the Company's rates on a "fair, just and reasonable" standard, (ii) regulate the Company's construction of new generation and transmission facilities by issuing certificates of public convenience and necessity, (iii) approve changes in ownership or control of the Company through sales of assets or otherwise, (iv) approve the issuance or assumption of securities or evidence of indebtedness, other than to RUS, and (v) administer the state laws assigning each jurisdictional electric utility the exclusive right to provide electric service within specified geographic boundaries.

In its order approving the Unwind Transaction, the KPSC stipulated that Big Rivers file a rate case within three years of the Unwind closing date or by July 2012. On March 1, 2011, the Company filed an application with the KPSC requesting, among other things, authority to adjust its rates for wholesale electric service. The KPSC entered an order on November 17, 2011, granting Big Rivers an annual revenue increase of $26.7 million. After several appeals and procedural events, this case is back before the KPSC for rehearing on four issues raised by Big Rivers, and three issues raised by an intervenor. The intervenor in the case seeks, among other things, an approximate $6.2 million reduction in the revenue relief granted in the order in connection with the depreciation study, and will presumably ask that any relief obtained be retroactive to the effective date of the rates approved in the order (September 1, 2011). The matters raised by Big Rivers on rehearing could increase Big Rivers' annual revenue by $2.7 million.

On March 28, 2012, Big Rivers submitted its application to the KPSC seeking approval to issue a term note secured under the Indenture to CoBank in the amount of $235 million, issue an unsecured note to CoBank in the amount of $50 million, issue a term note secured under the Indenture to CFC in the amount of $302 million and, in connection with the CFC term loan, to purchase interest bearing capital term certificates from CFC in the amount of approximately $43.2 million. The application with the KPSC was approved on May 25, 2012, and the planned closing date for these transactions with CoBank and CFC is June 29, 2012.

Big Rivers submitted an application on April 2, 2012, seeking KPSC approval for its 2012 ECP. This ECP will consist of $283.5 million of capital projects, primarily for a new scrubber at the Wilson Plant and a new SCR facility at the Green Plant, and certain additional operations and maintenance costs. The purpose of the ECP is to allow Big Rivers to comply, in the most cost-effective manner, with the EPA's rules for CSAPR and MATS.. Among other things, the ECP filing will seek to recover the costs of the ECP through the environmental surcharge tariff rider, an automatic cost-recovery mechanism that is similar in function to the fuel adjustment clause. The regulatory process is expected to last six months after the filing date.

RUS Regulation

In addition to the KPSC's direct regulation of the Company, RUS has certain rights through its loan documents with the Company that impact its operations (i.e., RUS must consent to the construction of new facilities which are part of the electric system, certain sales or dispositions of property, the execution of certain types of contracts and the making of loans or investments).

Environmental Regulations

Big Rivers is subject to various federal, state and local laws, rules and regulations with regard to air quality, water quality, waste management and other environmental matters.

These laws, rules and regulations often require Big Rivers to undertake considerable efforts and substantial costs to obtain licenses, permits and approvals from various federal, state and local agencies. If Big Rivers fails to comply with these laws, regulations, licenses, permits or approvals, Big Rivers could be held civilly or criminally liable. Big Rivers' operations are subject to environmental laws and regulations that are complex, change frequently and have tended to become more stringent over time. An inability to comply with environmental standards could result in reduced operating levels or the complete shutdown of facilities that are not in compliance.

Federal, state and local standards and procedures that regulate the environmental impact of Big Rivers' operations are subject to change. These changes may arise from continuing legislative, regulatory and judicial actions regarding such standards and procedures. Consequently, there is no assurance that environmental regulations applicable to Big Rivers' facilities will not become materially more stringent, or that Big Rivers will always be able to obtain and renew all required operating permits. Big Rivers cannot predict at this time whether any additional legislation or rules will be enacted that will affect its operations, and if such laws or rules are enacted, what the cost to Big Rivers might be in the future because of such actions.

From time to time, Big Rivers may be alleged to be in violation of or in default under orders, statutes, rules, regulations, permits or compliance plans relating to the environment. From time to time, Big Rivers may be defending notices of violation, enforcement proceedings or challenges to draft or final construction or operating permits. In addition, Big Rivers may be involved in legal proceedings arising in the ordinary course of business.

Clean Air

Clean Air Act. The Clean Air Act, as amended (the "Clean Air Act"), regulates emissions of air pollutants, establishes national air quality standards for major pollutants, and requires permitting of both new and existing sources of air pollution. Many of the existing and proposed regulations under the Clean Air Act could have a disproportionate impact on coal-based power plants, in particular older plants such as Big Rivers', because older plants may not have originally been required to install the same pollution control equipment as newer facilities. On the other hand, as retrofits become available and feasible, the

Company may incur greater costs than competing generating sources to bring facilities up to current standards. Several of the Company's facilities have, in the past decade, been retrofitted with new pollution control equipment, including flue gas desulfurization and selective catalytic reduction equipment, in response to regulatory changes.

Acid Rain Program. The acid rain program requires nationwide reductions of SO_2 emissions using a cap-and-trade program reducing allowable emission rates and allocating emission allowances to power plants for SO_2 emissions based on historical or calculated levels. The Company has sufficient SO_2 allowances to comply for the foreseeable future according to the Company's modeled emissions and allowance allocations.

Cross-State Air Pollution Rule. On July 11, 2008, the United States Court of Appeals for the D.C. Circuit ("D.C. Circuit") vacated the Clean Air Interstate Rule ("CAIR"), which was promulgated by the EPA in March 2005 to reduce nitrogen oxides ("NO_x") and SO_2 air emissions that move across certain state boundaries, primarily in the eastern United States. The CAIR would have been applicable in 28 eastern states, including Kentucky. The D.C. Circuit remanded the CAIR to EPA to promulgate a rule that is consistent with the court's opinion. On December 23, 2008, the court held that the original CAIR program will remain in effect until EPA promulgates such a new regulation.

On July 6, 2010, EPA published a proposed rule, known as the Transport Rule, as the replacement to the CAIR. On July 7, 2011, EPA published the final rule, now known as CSAPR. The CSAPR requires 27 states in the eastern half of the United States, including Kentucky, to significantly improve air quality by reducing power plant emissions that cross state lines and contribute to ground-level ozone and fine particulate pollution in other states. The final rule maintains the January 1, 2012 and January 1, 2014 phase-in dates that were in the proposed Transport Rule. The CSAPR imposes tighter emissions caps than the proposed Transport Rule. The CSAPR emission limits may be further reduced as the EPA finalizes more restrictive ozone and particulate matter National Ambient Air Quality Standards ("NAAQS") in the 2012-2013 timeframe.

The CSAPR is being challenged in the D.C. Circuit. On December 30, 2011, the court granted a stay of the CSAPR and directed the EPA to continue the administration of CAIR program in the interim. The court subsequently ordered an expedited schedule and heard oral arguments in April 2012. It is unknown when the court will issue its decision on the merits, but under the expedited schedule, the decision may be issued in the next few months. Big Rivers is in compliance with the current version of CAIR, Big Rivers projects it will have to reduce SO_2 emissions approximately 50% during Phase 3 of CSAPR and NO_x annual emissions by 16%. Big Rivers filed the ECP with the KPSC on April 2, 2012. Included in the filing are projects to replace the FGD at Wilson Plant and install an SCR at Green Plant Unit No. 2. Big Rivers believes that these two projects, along with other minor improvements, should allow Big Rivers to comply with the emission reductions contemplated in the CSAPR. Big Rivers has not yet obtained the necessary regulatory approval of its plans or environmental permits for these projects.

Mercury. In May 2005, EPA issued the Clean Air Mercury Rule ("CAMR") to permanently cap and reduce mercury emissions from fossil-fuel-fired electric utility steam generating units. CAMR was expected to reduce utility emissions of mercury from 48 tons per year to 38 tons per year in 2010 then to 15 tons per year in 2018. On February 8, 2008, the D.C. Circuit vacated CAMR, and reinstated the status of mercury as a hazardous air pollutant under the Clean Air Act. The result of this decision is that mercury emissions from such generating units are subject to the more stringent requirements of maximum achievable control technology ("MACT") applicable to hazardous air pollutants. In resolution of the CAMR litigation, the EPA entered into a consent decree that requires it to publish final hazardous air pollutants regulations for emissions from fossil-fuel-fired electric utility steam generating units by November 15, 2011.

On February 16, 2012, the final rule to reduce emissions of toxic air pollutants from fossil-fuel-fired electric utility steam generating units and to revise the new source performance standards ("NSPS") for fossil-fuel-fired electric utility steam generating units was published. The final rule, known as the MATS rule, requires coal-fired electric generation plants to achieve high removal rates of mercury, acid gases and other metals from air emissions. To achieve these standards, coal units with no pollution control equipment installed (i.e., uncontrolled coal units) will have to make capital investments and incur higher operating expenses. Coal units with existing controls that do not meet the required standards may need to upgrade existing controls or add new controls to comply. The MATS rule requires generating stations to meet the new standards three years after the rule takes effect, with specific guidelines for an additional one or two years in limited cases. The rule took effect on April 16, 2012. Big Rivers also included plans in its ECP filing that would address the mercury reductions contained in MATS. Big Rivers plans on installing activated carbon and dry sorbent injection systems at its Wilson, Coleman and Green Plants to meet these emission reductions. Big Rivers has not yet obtained the necessary regulatory approval of its plans or environmental permits for these projects.

Multi-Pollutant Legislation. In recent years, bills proposing mandatory emission reductions of NO_x, SO_2 and mercury and in some cases, carbon dioxide ("CO_2"), from electric utilities, have been introduce to the United States Senate. The proposed emission reductions were ultimately more stringent than the emission controls under prior Clean Air Act regulatory programs, CAIR and CAMR. The Senate did not pass any of these bills, but similar bills could be introduced and considered in the future. The Company cannot predict whether it or similar multi-pollutant legislation will ultimately become law. As a result, it is too early to determine what impact, if any, such a law and any implementing regulations may have on the Company.

Regional Haze. On June 15, 2005, the EPA issued the Clean Air Visibility Rule, amending regulations governing visibility in national parks and wilderness areas throughout the United States. Under the amended rule, certain types of older sources may be required to install best available retrofit technology ("BART"). The amended rules could result in requirements for newer and cleaner technologies and additional controls for particulate matter ("PM"), SO_2 and NO_x emissions from utility sources. Under the Clean Air Visibility Rule, the states were required to develop regional haze plans as part of their state implementation plans ("SIPs"), and identify the facilities that would have to reduce emissions and then set BART emissions limits for those facilities.

Kentucky submitted its regional haze SIP revisions to EPA on June 25, 2008. Kentucky submitted revisions to its regional haze SIP revisions to EPA on May 28, 2010. On March 30, 2012, EPA issued a final rule concluding its review of Kentucky's regional haze SIP revisions. In that final rule, EPA issued a limited approval of the revisions, which results in approval of Kentucky's entire regional haze SIP and all the elements. The EPA also issued a limited disapproval of the SIP revisions to the extent that the revisions rely on the CAIR program to address the impact of emissions from Kentucky's fossil-fuel-fired electric utility steam generating units. The issuance of the limited disapproval provides EPA with the authority to issue a federal implementation plan ("FIP") at any time.

On December 30, 2011, EPA proposed to find that the trading program in the CSAPR would achieve greater reasonable progress towards visibility goals than would BART in the states in which CSAPR applies. Based on this proposed finding, EPA also proposed to revise the regional haze rule to allow states to substitute participation in the CSAPR trading programs for source-specific BART. In order to address the deficiencies in SIPs that rely on their participation in CAIR to satisfy certain regional haze requirements, EPA also proposed a FIP, which allow states to replace reliance on the CAIR requirements in those SIPs with reliance on the CSAPR as an alternative to BART. EPA has not taken final action on this proposed rule yet.

Under Kentucky's regional haze SIP, the Company's facilities are exempt from the requirement to install BART for SO_2, NO_x and PM emissions. The exemption for SO_2 and NO_x emissions is based on Kentucky's participation in the CAIR program. Because the CAIR program was invalidated, states cannot rely on their participation in the CAIR program as a substitute for meeting BART requirements. As discussed above, EPA has proposed to allow states subject to CSAPR to rely on their participation in the CSAPR trading programs to substitute source-specific BART. If that rule is not finalized, states, including Kentucky, may have to evaluate SO_2 and NO_x emissions from fossil-fuel-fired electric utility steam generating units, including Big Rivers' facilities. It is therefore possible that the Company will be required to install BART for SO_2 and NO_x emissions at certain facilities. The determination under the regional haze SIP to exempt the Company's facilities from BART for PM emissions was based on air quality modeling information submitted by the Company in May 2007. At that time, the modeling information showed that PM emissions from the Company's facilities were not contributing to regional haze at any Class I area.

National Ambient Air Quality Standards. The Clean Air Act also requires EPA to establish NAAQS for certain air pollutants. When a NAAQS has been established, each state must identify areas in its state that do not meet the EPA standard (known as "non-attainment areas") and develop regulatory measures in its SIP to reduce or control the emissions of that air pollutant in order to meet the standard and become an "attainment area." EPA is in the process of reviewing NAAQS for certain air pollutants that are emitted by power plants including NO_x, SO_2, ozone, and PM. When a stricter NAAQS is finalized and becomes effective, air pollution sources including power plants, could face stricter emission standards. The impact of any new standards under the NAAQS program will depend on the final federal regulations and resulting revisions to Kentucky's SIP, so Big Rivers cannot determine such impacts at this time.

Opacity. PM emissions from the Company's facilities have, in the past, resulted in notices of violation and occasional complaints from neighbors and local government agencies. The complaints have declined in recent years, following the installation of SCR and/or FGD air pollution controls at the Wilson Plant, the Green Plant, the Henderson Plant and the Coleman Plant. Even though there have been improvements in some of the emissions characteristics, plume opacity and other impacts may continue to arise in connection with the installation and the operation of the SCR and FGD controls. Additionally, the scrubbed units at the Green, Coleman and Wilson plants are "wet scrubbed" units with "wet stacks." A phenomenon commonly associated with wet scrubbers is the occasional and unexpected appearance of a visible plume that begins some distance after the exhaust exits the stack. The actual cause of the plume is unknown. The Company continues to monitor the occurrence of the plumes and address notices of violations or other agency actions as they arise. Although no material fines or penalties have been assessed against the Company, the Company has sought permit amendments to address this issue. It is possible that additional investment or pollution controls may be required to reduce these impacts.

New Source Review. In 1999-2000, the U.S. Justice Department, acting on behalf of the EPA, filed a number of complaints and notices of violation against multiple utilities across the country for alleged violations of the New Source Review ("NSR") provisions of the Clean Air Act. Generally, the government alleged that projects performed at various coal-fired units were major modifications, as defined in the Clean Air Act, and that the utilities violated the Clean Air Act when they undertook these projects without obtaining major source permits under the Prevention of Significant Deterioration ("PSD") and/or Title V programs. As part of the enforcement effort, the EPA also sent requests for information letters to numerous other utilities requesting extensive and detailed information on the repairs and modifications made by those utilities to their coal fired boilers. In 2000, WKE received an information request from EPA, when it was the operator of the facilities, and WKE submitted the requested information to EPA. To date, EPA has not requested any additional information.

In 2007, the U.S. Supreme Court upheld EPA's definition of a major modification as one that increases the actual annual emission of a pollutant from a facility above the actual average for the two prior years, and, under President Obama's administration, EPA has announced plans to enforce the NSR provisions. The Company cannot predict whether EPA or other governmental authorities will consider any of the past maintenance projects or capital improvements at its facilities to have violated NSR requirements as a result of the uncertain interpretation of this program and recent court decisions. If violations are established, the Company could be required to install new pollution control equipment in addition to the modifications that have already been completed or planned, and be liable for other payments or penalties.

Global Climate Change

CO_2, a major constituent of emissions from fossil-fuel combustion, and other greenhouse gases ("GHG") are generally believed to be linked to global warming resulting in climate change. Control of such emissions is the subject of debate in the United States, on local, state and national levels. In the United States, no federal legislation limiting GHG emissions has yet been enacted, but there have been significant developments relating to monitoring and regulation of GHG emissions by EPA, certain state governments and regional governmental organizations. In addition, the United States Congress is considering federal legislation that could impose a cap-and-trade system or other measures to reduce GHG emissions, such as carbon tax.

EPA Regulatory Action under the Clean Air Act

On April 2, 2007, the United States Supreme Court issued a decision in Massachusetts v. EPA holding that EPA has the authority to regulate GHG emissions under the Clean Air Act. Air pollutants, including GHGs, which are regulated by actually controlling emissions under any Clean Air Act program, must be taken into account when considering permits issued under other programs, such as the PSD Permit Program or the Title V Permit Program. A PSD permit is required before commencement of construction of new major stationary sources or major modifications of such sources and contains requirements including but not limited to the application of BACT. Title V permits must be applied for within one year a source becomes subject to the program. Title V permits are operating permits for major sources that consolidate all Clean Air Act requirements (arising, for example, under the Acid Rain, New Source Performance Standards, National Emission Standards for Hazardous Air Pollutants, and/or PSD programs) into a single document, provide for review of the documents by EPA, state agencies and the public, and contain monitoring, reporting and certification requirements.

On May 13, 2010, EPA issued a final rule for determining the applicability of the PSD and Title V programs to GHG emissions from major stationary sources. The rule, known as the "Tailoring Rule," establishes criteria for identifying facilities required to obtain PSD permits and the emissions thresholds at which permitting and other regulatory requirements apply. The applicability threshold levels established by this rule include both a mass-based calculation and a metric known as the carbon dioxide equivalent, or "CO_2e", which incorporates the global warming potential for each of the six individual gases that comprise the collective GHG defined by EPA. The Tailoring Rule established two initial steps for phasing in the GHG permitting requirements and indicated a third phase would be established at a later date.

The first step became effective on January 2, 2011, and requires sources subject to PSD and/or Title V permits due to their non-GHG emissions (such as fossil-fuel based electric generating facilities for their NO_x, SO_2 and other emissions) to address GHG emissions in new permit applications or renewals. Construction or modification of major sources will become subject to PSD requirements for their GHG emissions if the construction or modification results in a net increase in the overall mass of GHG emissions exceeding 75,000 tons per year ("tpy") on a CO_2e basis. New and modified major sources required to obtain a PSD permit would be required to conduct a BACT review for their GHG emissions. According to EPA guidance, most of the initial permitting decisions will focus on improved energy efficiency.

With respect to Title V requirements under the first step of the Tailoring Rule, effective January 2, 2011, sources required to have Title V permits for non-GHG pollutants are required to address GHGs as part of their Title V permitting. When any source applies for, renews, or revises a Title V permit, Clean Air Act requirements for monitoring, recordkeeping and reporting will be included in the renewed permit. This part of the rule does not create any new emissions controls or limitations for GHGs; it only creates the requirement for these sources to monitor, record and report their GHG emissions. In the Tailoring Rule, EPA notes that the existing requirements created by the October 30, 2009, final rule for mandatory monitoring and annual reporting of GHGs from various categories of facilities including electric generating facilities will generally be sufficient to satisfy these new Title V requirements. The GHG monitoring and reporting rule requires facilities to have begun data collection on January 1, 2010. On March 18, 2011, EPA issued a final rule extending the deadline to submit the first annual reports from March 31, 2011, to September 30, 2011. The second step of the Tailoring Rule was effective July 1, 2011, and is applicable to new facilities or modification to existing facilities that exceed certain GHG emission thresholds, even if the facility is not subject to PSD or non-GHG emissions. The second phase requirements apply to any new, major sources as well as to any major modification of existing facilities, depending on their levels of emissions of both GHG and non-GHG pollutants

On March 8, 2012, EPA's proposed rule for the third step in the Tailoring Rule was published. EPA proposes to maintain the applicability thresholds for GHG-emitting sources at the current levels. EPA also proposes two permitting streamlining approaches to improve the administration of the PSD and Title V permitting programs.

In addition to the PSD permit program, EPA is also in the process of developing a GHG regulatory program under the NSPS provisions of the Clean Air Act. On December 23, 2010, EPA entered a settlement agreement and agreed to issue NSPS and emission guidelines for GHG emissions from new and modified fossil-fuel-fired fossil-fuel-fired electric utility steam generating units. On April 13, 2012, EPA's proposed rule for standards of performance for GHG emissions for new fossil-fuel-fired electric utility steam generating units was published. EPA may issue more rulemakings in order to meet the terms of the settlement agreement.

The Company's costs of compliance with these new regulations are not fully known at this time. The requirements for monitoring, reporting and record keeping with respect to GHG emissions from existing units should not have a material adverse effect, but the consequences of new permit requirements in connection with new units or modifications of existing units could be significant, as could any new proposed regulations affecting permitting and controls for the Company's existing units.

Federal Legislation

In addition to EPA's regulatory actions establishing federal regulation of GHG emissions, the United States Congress has considered several energy and climate change-related pieces of legislation that proposed, among other things, a cap-and-trade system to regulate and reduce the emission of CO_2 and other GHGs and a federal renewable energy portfolio standard. The 112th Congress may consider new GHG proposals and it is possible that Congress will agree to set limits on GHG emissions or set clean or renewable energy standards for the electric utility sector. The timeline and impact of climate change legislation cannot be accurately assessed at this time, but it is expected that any enactment of statutes to regulate GHG emissions will have a significant impact on fossil-fueled generation facilities.

Litigation

Many of the issues raised by global climate change are being litigated in courts throughout the United States. Plaintiffs have asserted in some cases that GHG emissions from electric generation are causing a public nuisance and should be abated by electric generation facilities. The Company cannot currently predict how GHG emissions issues will arise in connection with pending or future permit proceedings or whether litigation based on climate change issues will adversely affect its operations, or its construction and development plans.

Water

The Federal Clean Water Act regulates the discharge of process wastewater and certain storm water under the National Pollutant Discharge Elimination System ("NPDES") permit program. Such permits are issued for five-year periods and continue in effect if renewal applications are timely filed. At the present time, applications for renewal of some of the Company's NPDES permits are awaiting review by the Kentucky Division of Water. The Company has all other material required permits under the program for all of its electric generating plants. The water quality regulations require the Company to comply with Kentucky's water quality standards, including sampling and monitoring of the waters discharged from the facilities. The Company continually samples and monitors the discharges and reports the results thereof in accordance with its permits.

Section 316(b) of the Clean Water Act requires the EPA to ensure that the location, design, construction and capacity of cooling water intake structures reflect the best technology available to protect aquatic organisms from being killed or injured by impingement or entrainment. In February 2004, the EPA issued final regulations establishing standards for cooling water intake structures at existing large power plants. The rule provided several compliance alternatives for existing plants such as using existing technologies, adding fish protection systems or using restoration measures.

On January 25, 2007, the United States Second Circuit Court of Appeals remanded key components of the Clean Water Act 316(b) Phase II Rule. The court ruled that EPA could not allow use of restoration measures to satisfy performance standards, nor could it consider cost-benefit analysis in selecting "best technology available." The United States Supreme Court heard the appeal of the Second Circuit decision and held on April 1, 2009, that it is permissible for utility companies and regulators to apply cost-benefit analysis under the Clean Water Act. EPA published the new 316(b) rules on April 20, 2011, and EPA is required to finalize the rulemaking no later than July 27, 2012.

The impact of Section 316(b) on Big Rivers is limited to the Robert A. Reid Plant ("Reid Plant") and the Coleman Plant. The degree of such impact will depend upon the form of the new rule that EPA publishes. If EPA allows a cost-benefit analysis to determine the best technology available, the Company expects the impact to the Reid Plant and the Coleman Plant will be minimal based on information obtained from previous studies conducted on the quantity and type of fish impinged on the intake screens at Reid Plant and Coleman Plant.

Other Environmental Matters

The Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended ("CERCLA" or "Superfund"), requires cleanup of sites from which there has been a release or threatened release of hazardous substances and authorizes the EPA to take any necessary response action at Superfund sites, including ordering potentially responsible parties ("PRPs") liable for the release to take or pay for such actions. PRPs are broadly defined under CERCLA to include past and present owners and operators of, as well as generators of wastes sent to, a site. Big Rivers historically has sent wastes, such as coal ash or wastewater that could have included hazardous substances, to third-party disposal sites or treatment plants. Based on such disposal, the Company can become a PRP with respect to such sites. The Company is not aware of any material liabilities with respect to such disposal, but can provide no assurance that such liabilities will not be asserted in the future. In addition, the Company has experienced and is likely to continue to experience in the future spills and releases of fuel oil and other materials that could trigger cleanup obligations under CERCLA and result in additional compliance costs. As a result, there can be no assurance that the Company will not incur liability under CERCLA in the future.

Electro-Magnetic Fields. A number of electrical industry studies have been conducted regarding the potential long-term health effects resulting from exposure to electro-magnetic fields ("EMF") created by high voltage transmission and distribution equipment. At this time, any relationship between EMF and certain adverse health effects appears inconclusive; however, electric utilities have been experiencing challenges in various forms claiming financial damages associated with electrical equipment which creates EMF. In the future, if the scientific community reaches a consensus that EMF presents a health hazard, the Company may be required to take remedial actions at its facilities. The cost of these actions cannot be estimated with certainty at this time. Such costs, however, could be significant, depending on the particular mitigation measures undertaken, especially if relocation of existing power lines is required.

Coal Ash. The Company's coal-based generating facilities produce coal ash waste that requires disposal. The Company disposes of the coal ash in its onsite landfills and impoundments and possesses the proper industrial solid waste permits to operate its landfills in accordance with local, state and federal regulations and laws. However, the Company must continually expand the capacity of its landfills and waste management facilities to accommodate larger amounts of ash. If the Company becomes unable to dispose of coal ash on site, its disposal costs may increase considerably. On the other hand, the Company is continually evaluating methods for beneficial reuse of waste ash. Currently, all of the ash the Company generates is exempt from regulation as "hazardous waste."

On June 21, 2010, the EPA published a proposed rule describing two possible regulatory options it is considering under the Resource Conservation and Recovery Act ("RCRA") for the disposal of coal ash generated from the combustion of coal by electric utilities and independent power producers. Under either option, EPA would regulate the construction of impoundments and landfills, and seek to ensure both the physical and environmental integrity of disposal facilities.

Under the first proposed regulatory option, EPA would list coal ash destined for disposal in landfills or surface impoundments as "special wastes" subject to regulation under Subtitle C of RCRA. Subtitle C regulations set forth EPA's hazardous waste regulatory program, which regulate the generation, handling, transport and disposal of wastes. The proposed rule would create a new category of waste under Subtitle C, so that coal ash would not be classified as a hazardous waste, but would be subject to many of the regulatory requirements applicable to such wastes. Under this option, coal ash would be subject to technical and permitting requirements from the point of generation to final disposal. Generators, transporters, and treatment, storage and disposal facilities would be subject to federal requirements and permits. EPA is considering imposing disposal facility requirements such as liners, groundwater monitoring, fugitive dust controls, financial assurance, corrective action, closure of units, and post-closure care. This first option also proposes requirements for dam safety and stability for surface impoundments, land disposal restrictions, treatment standards for coal ash, and a prohibition on the disposal of treated coal ash below the natural water table. The first option would not apply to certain beneficial reuses of coal ash.

Under the second proposed regulatory option, EPA would regulate the disposal of coal ash under Subtitle D of RCRA, the regulatory program for non-hazardous solid wastes. Under this option, EPA is considering issuing national minimum criteria to ensure the safe disposal of coal ash, which would subject disposal units to location standards, composite liner requirements, groundwater monitoring and corrective action standards for releases, closure and post-closure care requirements, and requirements to address the stability of surface impoundments. Existing surface impoundments would not have to close or install composite liners and could continue to operate for their useful life. The second option would not regulate the generation, storage, or treatment of coal ash prior to disposal, and no federal permits would be required.

The proposed rule also states that EPA is considering listing coal ash as a hazardous substance under CERCLA, and includes proposals for alternative methods to adjust the statutory reportable quantity for coal ash. The extension of CERCLA to coal ash could significantly increase the Company's liability for cleanup of past and future coal ash disposal.

EPA issued a Notice of Data Availability for comment on October 12, 2011. EPA is conducting a human health risk assessment on coal combustion residual beneficial use to be released prior to the final rule. EPA has not decided which regulatory approach it will take with respect to the management and disposal of coal ash. The Company is therefore unable to determine the effects of this proposed rule at this time.

As part of EPA's scrutiny of how ash impoundments are permitted and operated, EPA recently assessed ash impoundments at many facilities throughout the country, including some of the Company's facilities. A dam safety assessment report for Reid Plant, Green Plant and Station Two was prepared for EPA in December 2009. All of the ash ponds at these facilities received "fair" ratings – a rating that reflected EPA's view that the Company's geotechnical information was not complete – but no critical deficiencies were noted. Minor repairs required by EPA during this review were completed during the 2010 construction season. The geotechnical investigation recommended by EPA has been completed by the Company. Coal ash waste management and disposal is an evolving issue and the Company expects to continue to incur costs to upgrade and expand its ash impoundments as regulations change.

FERC Regulation

As a transmission owning, generation owning, and market participant member of the MISO, the Company's sale of power at wholesale and its transmission of power in interstate commerce are regulated by the Federal Energy Regulatory Commission ("FERC"). The KPSC maintains jurisdiction over the Company's wholesale power rates to its Members and over the transmission rates applicable under the MISO's FERC-approved Open Access Transmission, Energy and Operating Reserve Markets Tariff ("MISO Tariff").

Energy Policy Act of 1992

The Energy Policy Act of 1992 ("EPAct 1992") made fundamental changes in the federal regulation of the electric utility industry, particularly in the area of transmission access. The purpose of these changes, in part, was to bring about increased competition in the wholesale electric power supply market. These changes have increased, and will continue to increase, competition in the electric utility industry. Specifically, EPAct 1992 provided that any electric utility, federal power marketing agency or any other person generating electric energy for sale for resale may apply to FERC for an order requiring a transmitting utility like the Company to provide interconnection and transmission services to the applicant. After notice and an opportunity for hearing, FERC may issue an order under Section 210 or 211 of the Federal Power Act ("FPA") requiring such interconnection or transmission service to be provided, subject to appropriate compensation to the utility providing such service. However, EPAct 1992 specifically denied FERC authority to require "retail wheeling" under which a retail customer of one utility could obtain electric power and energy from another utility or nonutility power generator and require a transmitting utility to "wheel" it to the retail customer.

Order No. 888 and Successor Orders

In 1996, to remove impediments to competition in the wholesale bulk power marketplace and to bring more efficient lower cost power to the nation's electricity consumers, FERC issued Orders Nos. 888 and 889. Orders Nos. 888 and 889, as amended by Orders Nos. 888-A and 889-A in 1997, were intended to deny public utilities any unfair advantage over competitors resulting from their ownership and control of transmission facilities by requiring each FERC-jurisdictional public utility to file a pro forma OATT and to follow certain rules of conduct for open-access providers, including a requirement to separate operationally power sales from transmission. In Order Nos. 890, 890-A and 890-B, issued (respectively) in February and December 2007 and June 2008, FERC reaffirmed and modified the requirements under Order Nos. 888 and 888-A, specifically, by modifying the pro forma OATT provisions on (among other things) calculating available transfer capability, transmission planning, point-to-point transmission service options, energy imbalance service, rollover rights for long-term firm transmission service, and the price caps on capacity reassignments. Under the reciprocity requirement adopted in Order No. 888 and reaffirmed in Order No. 890, non-jurisdictional utilities like the Company must provide comparable transmission service as a condition of receiving service from jurisdictional utilities under the pro forma OATT. The Company's transmission facilities located in the Eastern Interconnection provided transmission service under an OATT that was approved by FERC for reciprocity purposes until the Company became a member of MISO in December 2010 and its OATT was terminated. Since December 2010, the Company's transmission facilities have been under the functional control of MISO and operated under the terms and conditions of the MISO Tariff.

Energy Policy Act of 2005

On August 8, 2005, President Bush signed into law the Energy Policy Act of 2005 ("EPAct 2005"). The significant provisions of EPAct 2005 that could affect the Company are in the areas of (1) reliability; (2) siting of new transmission facilities; (3) potential FERC authority over transmission service and the rates of non-rate-regulated utilities; (4) native load obligations; and (5) expansion of FERC's enforcement authority. In addition, Congress repealed the Public Utility Holding Company Act of 1935 ("PUHCA 1935"), and replaced it with the Public Utility Holding Company Act of 2005 ("PUHCA 2005"), thereby effectively repealing many of the more onerous provisions of PUHCA 1935. As an electric cooperative, the Company generally is not subject to the new requirements of PUHCA 2005. EPAct 2005 also created incentives for the construction of transmission facilities; gave FERC authority to establish mandatory reliability standards through a new entity that FERC would certify as the Electric Reliability Organization ("ERO"); authorized the Department of Energy and FERC to grant permits enabling entities, in certain circumstances, to use a federal right of eminent domain to build new transmission lines; and adopted provisions enabling transmission providers to reserve transmission capacity for their native load service obligations. FERC has adopted regulations to implement the new regulations and requirements concerning siting, transmission access, native load preferences and enforcement.

Concerning the expansion of FERC's authority to order transmission access to transmission systems owned or operated by non-rate-regulated utilities, EPAct 2005 added new section 211A to the FPA. Section 211A authorizes FERC to order non-rate-regulated utilities like the Company to provide transmission service at rates and terms that are comparable to those by which the non-rate-regulated utility provides transmission service to itself. However, the non-rate-regulated utilities subject to any such requirements are not subject to the full panoply of FERC regulations established under Section 205 and 206 of the FPA that are applicable to transmission-owning public utilities. FERC also is required, with certain limited exceptions, to exempt any non-rate-regulated utility that sells less than 4 million kWh per year. FERC has declined to order transmission access pursuant to Section 211A on a generic basis, and instead will act on a case-by-case basis. In December 2011, FERC issued its first order under Section 211A in which FERC directed a non-jurisdictional transmission provider to provide transmission service on terms and conditions that are comparable to those under which the transmission provider provides transmission service to itself and that are not unduly discriminatory or preferential. That order is currently pending rehearing.

In 2006, FERC used its authority under Section 215 of the FPA to certify the North American Electric Reliability Corporation ("NERC") as the ERO responsible for the development of mandatory reliability standards subject to FERC review and approval. NERC's mandatory reliability standards apply to any entity that owns, operates or uses the bulk power system. Under EPAct 2005, FERC and the ERO have authority to impose penalties for violations of the reliability standards. In March and July 2007, FERC issued (respectively) Order Nos. 693 and 693-A largely approving the first set of reliability standards filed by NERC for FERC review and approval. FERC also directed NERC to consider revisions to a number of the standards, and other reliability standards and amendments proposed by NERC remain pending before FERC. Since 2007, the Commission has approved and directed modification to many more NERC reliability standards. As an owner and operator of generation and transmission facilities, the Company is subject to certain of the NERC reliability standards. The Company is currently scheduled for a routine audit of its compliance with the reliability standards. The audit is scheduled to occur at the Company's facility from May 6, 2013, to May 10, 2013. If the auditors identify areas of non-compliance, the Company could be subject to penalties or sanctions.

EPAct 2005 also added new sections 220, 221 and 222 to the FPA, which generally prohibit fraud and manipulation in the energy markets and promote price transparency. Under FERC's implementing rules, the anti-fraud rules apply to all entities, including non-jurisdictional utilities, to the extent they engage in activities or transactions in connection with sales and transmission services subject to FERC's public-utility jurisdiction.

Order No. 1000

In 2011, FERC issued Order No. 1000 to build on certain of its reforms in Order No. 888 and Order No. 890. The requirements set forth in Order No. 1000 apply only to "new transmission facilities" and include the consideration and evaluation of possible transmission alternatives at a regional transmission planning level and the development of a regional transmission plan; the development of procedures for interregional planning to determine whether interregional transmission facilities are more efficient or cost effective than certain regional facilities; the development of methods for regional and interregional cost allocation that is roughly commensurate with the estimated benefits; and, for those projects eligible for cost sharing, removal of transmission providers' "right of first refusal" in order to allow competition from non-incumbent developers. In general, Order No. 1000 permits each region to develop its own processes and procedures to comply with the requirements. MISO, of which Big Rivers is a member, continues to progress through a stakeholder process to discuss and develop proposals for compliance with Order No. 1000. As of the date of this Disclosure Statement, however, since MISO has not fully developed such processes and procedures, the impact of Order No. 1000 on the Company cannot be determined.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Risk Management Policies

The Company is exposed to significant market risks associated with electricity and coal prices, counter-party credit exposure, interest rates and equity prices. Interest rate risk is associated with the changes in interest rates that impact its variable rate debt instruments and fixed income investments. The Company's energy related commodity price risks involve changes in the market price of power, natural gas, and solid fuels and the impact of such changes on its ability to generate sufficient revenue to cover the Company's operational costs. Big Rivers has established comprehensive risk management policies to monitor and manage these risks. The Company's vice president of enterprise risk management and strategic planning is responsible for monitoring and reporting on its risk management policies, including delegation of authority levels. The Company has an Internal Risk Management Committee that regularly meets and the vice president of enterprise risk management and strategic planning reports to the Board of Directors monthly. The vice president of enterprise risk management and strategic planning is responsible for oversight of market risk, credit risk, etc., including monitoring exposure limits.

To manage the Company's market risks, it may enter into various derivative instruments including swaps, forward contracts, futures contracts and options. Management believes adequate safeguards, reporting mechanisms, and procedures are in place to protect the Company from unauthorized use of such derivative instruments. The Company has established certain risk management strategies relating to the sales and purchase prices for the commodities which form its core business, in order to provide insulation from volatile market prices. With respect to the Company's power sales, the Board of Directors has established guidelines which are intended to ensure that derivatives and other financial instruments are used for hedging purposes and not for speculation. Those guidelines provide that hedging activity shall be used only to minimize risk and not to create any greater risk. Risk management status and performance must be reported to the Board of Directors on a monthly basis, and counterparties must meet capitalization requirements before the Company will engage with such counterparty.

Electricity and Coal Price Risk

The Company is exposed to the impact of market fluctuations in the prices of electricity and coal as a result of its ownership and operation of electric generating facilities. The Company's exposure to coal and purchased power risk is limited by cost-based Member rate recovery through two cost-recovery clauses, namely the fuel adjustment clause ("FAC") and the non-FAC purchased power adjustment. Due to timing of the cost-recovery, there is a two month lag for the FAC between when costs are incurred and when the Member portion is recovered through rates. For the non-FAC purchase power adjustment due to timing of the cost recovery, there is a two month lag between when the costs are incurred and when the Member-Smelter portion is recovered through rates that represent approximately two-thirds of the costs. Generally, the remaining one-third of the non-FAC purchase power adjustment cost, related to the non-smelter members, is deferred as a regulatory account over a twelve month period beginning July 1 of a given year through June 30 of the following year. The non-smelter member recovery (whether positive or negative) begins on September 1, two months after the end of the deferral period, and ends twelve months later on August 31.

Price risk represents the potential risk of loss from adverse changes in the market price of electricity or coal. Because the Company is long on power, both capacity and energy, it is exposed to the illiquidity of the long-term power market and volatility of the market price of electricity and coal. The Company's long position in the energy market is approximately 150 MWs or 8% of its availability capacity. The excess capacity and energy will be consumed in the future through normal growth. Further, price risk resulting from the volatility in the price of coal is off-set by a month recovery rider for fuel that has been approved by the KPSC.

The Company generally only enters into market power sales contracts that qualify for the normal sales and purchases exception. Income recognition and realization related to normal sales and normal purchases contracts generally coincide with the physical delivery of the power. For all such contracts, as long as completion of the transaction remains probable, no recognition of the contract's fair value is required to be reported in the Company's financial statements until settlement or physical delivery.

In a further effort to mitigate coal price volatility, the Company has established a hedge policy in which near-term requirements of fuel are secured at a higher percentage and future year coal requirements are contracted at a varying percent of open fuel position per year across a five-year time horizon. Thus, in any given year within the five-year hedge plan, there is a portion of fuel supply contracted at known prices.

Marketable Securities Price Risk; Pension Plan Assets

The Company maintains investments to fund the cost of providing its non-contributory defined benefit retirement plans. Those investments are exposed to price fluctuations in equity markets and changes in interest rates. The Company has established asset allocation targets for its pension plan holdings that take into consideration the investment objectives and the risk profile with respect to the trust in which the assets are held. The target asset allocation for equity securities is 65% of the value of the plan assets and the holdings are diversified to achieve broad market diversification to reduce exposure to and any adverse impact of a single investment, sector or geographic region. A significant decline in the value of plan asset holdings could require the Company to increase its funding of the pension plan in future periods, which could adversely affect cash flows in those periods. Additionally, a decline in the fair value of plan assets, absent additional cash contributions to the plan, could increase the amount of pension cost required to be recorded in future periods, which could adversely affect its results of operations in those periods. A 10% decline in the fair value of the Company's plan assets equals $2.8 million.

Interest Rate Risk

The Company is exposed to risk resulting from changes in interest rates as a result of the use of variable rate debt as a source of financing as well as the fixed income investments in its various portfolios. The Company manages its interest rate exposure by limiting the total amount of its variable rate exposure to within a particular amount of its total debt and by actively monitoring the effects of market changes in interest rates. As of December 31, 2011, $727.6 million of $786.4 million of outstanding long-term indebtedness secured under the Mortgage Indenture accrued interest at fixed rates to their final maturity. As of December 31, 2011, the Company had outstanding variable rate debt of $58.8 million. This debt consists of the Series 1983 Bonds which mature in 2013.

Commodity Price Risk

The average rate to the Members is affected by the price Big Rivers can obtain in the market for energy produced by its generating facilities in excess of the Members' requirements. Higher prices produce greater Non-Member revenue that is used to offset Member revenue requirements. The Company's exposure to the risk of fluctuating power prices is declining as its historically high levels of excess generation are being used to meet increasing Member requirements, including the Smelters. The Company's excess capacity generation in 2011 is approximately 8%.

Additionally, if one or more the Company's generating facilities is not able to produce power when required due to operational factors, the Company may have to forego Non-Member sales opportunities or purchase energy in the wholesale market at higher prices to meet Member requirements.

Credit Risk

Credit risk represents the loss that the Company would incur if a counterparty failed to perform under its contractual obligations. To reduce credit exposure, the Company establishes credit limits and seeks to enter into netting agreements with counterparties that permit it to offset receivables and payables. To control the credit risk associated with credit sales of power the Company utilizes a credit approval process, monitor counterparty limits and require that counterparties have adequate credit ratings. The Company attempts to further reduce credit risk with certain counterparties by entering into agreements that enable it to obtain collateral or to terminate or reset the terms of transactions after specified time periods or upon the occurrence of credit-related events. Where appropriate, the Company also obtains cash or letters of credit from counterparties to provide credit support outside of collateral agreements, based on financial analysis of the counterparty and the regulatory or contractual terms and conditions applicable to each transaction.

The Company generally executes only physical delivery contracts. The Company frequently uses master collateral agreements to mitigate certain credit exposures. The collateral agreements provide for a counterparty to post cash or letters of credit in excess of an established threshold. The threshold amount represents an unsecured credit limit, determined in accordance with the Company's credit policy. Collateral agreements also provide that the inability to post collateral is sufficient cause to terminate contracts and liquidate all positions.

Due to the possibility of extreme volatility in the prices of energy commodities and derivatives, the market value of contractual positions with individual counterparties could exceed established credit limits or collateral provided by those counterparties. If such a counterparty were then to fail to perform its obligations under its contract, the Company could sustain a loss that could have a material impact on its financial results. The probability of a material impact is lessened by the fact that the Company only has a relatively small amount of power to sell long-term and presently does not plan on transacting multi-year long-term contracts.

BIG RIVERS' MEMBERS

General

The Members are local consumer-owned cooperative corporations serving retail residential, commercial and industrial customers on a non-profit basis. The territories served by the Members include portions of 22 counties in western Kentucky. The Members serve approximately 113,000 consumers. The majority of the Members' customers are individual residences.

Territorial Integrity

Distribution cooperatives generally exercise a monopoly in their service areas, except in certain areas where a municipality or the Tennessee Valley Authority ("TVA") may have the concurrent right to provide retail electric service. Under a Kentucky statute adopted in 1972, the Members are "Retail Electric Suppliers" that are certified by the KPSC as the exclusive suppliers of energy to their respective certified service areas. Thus, the Members are the exclusive suppliers of energy to electricity consumers located in their respective certified service areas. If a Retail Electric Supplier is providing adequate service within its certified territory, other Retail Electric Suppliers may not sell power to retail customers located within that certified territory. Municipal utilities are not Retail Electric Suppliers under the statute. If a new electric consuming facility locates in two or more adjacent certified territories, the KPSC determines which Retail Electric Supplier may provide retail electric service to that facility based on a number of factors, designed to avoid wasteful duplication of electric generation facilities.

Rate Regulation of Members

The KPSC regulates the retail energy rates of the Members. Under Kentucky law, a utility may revise its rates on 30 days' notice to the KPSC of the proposed changes and the effective date of such changes. The KPSC has the statutory power to suspend such changes pending a hearing for a period not to exceed six months from the proposed effective date of such changes. This suspension period begins with the effective date named by the utility, and thus, the utility may avoid or minimize the effect of such suspension by naming an early effective date in its notice to the KPSC. Rate changes may be placed in effect, in whole or in part, during any such suspension period on a finding by the KPSC that an emergency exists or that the utility's credit or operations will be materially impaired by the suspension. Rates placed into effect on an emergency basis are subject to refund to the extent that the final rates approved by the KPSC are lower than the emergency rates. The KPSC's decision on a new rate schedule filed by a utility must be issued not later than ten months after the filing of the rate schedule.

Member Information

Financial Information

The Members operate their systems on a not-for-profit basis. Accumulated margins constitute patronage capital for the consumer members. Refunds of accumulated patronage capital to the individual consumer members are made from time to time on a patronage basis subject to limitations contained in Member mortgages to the RUS, if applicable.

The Members are the Company's owners and not its subsidiaries. Except with respect to the obligations of the Members under their respective wholesale power contracts and the Smelter Agreements, Big Rivers has no legal interest in, or obligation in respect of, any of the assets, liabilities, equity, revenue or margins of its Members, other than its rights under these contracts. The revenues of the Members are not pledged to Big Rivers, but their revenues are the source from which they pay for power and energy and transmission services purchased from Big Rivers. Revenues of the Members are, however, often pledged under their respective mortgages. Tables 1 through 6 in Appendix B present a three-year summary of the balance sheets, statements of operations and selected statistical information with respect to the Members.

Statistical Information

The Company serves directly and indirectly a diverse customer base that includes farms and residences, commercial and industrial facilities, mining, irrigation and other miscellaneous customers. Farm and residential customers constitute the largest class of customers in terms of numbers throughout the Member service areas. The table below shows energy sales and revenue by customer class for the year 2011 for the Members.

2011 Sales By Members [(1)]

	kWh Sales (in thousands)	kWh Sales (%)	Revenue (in thousands)	Revenue (%)
Farm & Residential	1,530,359	14%	$112,855	23%
Commercial and Industrial (excluding the Smelters)	1,746,161	17%	86,044	17%
Aluminum Smelters	7,228,844	69%	303,364	60%
Other	3,409	0%	437	0%
Total	10,508,773	100%	$502,700	100%

(1) The information in this table has been compiled by Big Rivers from information obtained from the Annual Statistical Report Rural Electric Borrowers (Publication 201.1) and RUS Form 7 prepared by the Members and filed with RUS. Big Rivers has not independently verified this information

THE SMELTER AGREEMENTS

The Company and Kenergy have entered into electric service arrangements with the Smelters. The Smelters have largely identical obligations under the agreements described below, so the following discussion does not distinguish between obligations to a particular Smelter, even though, from a legal perspective, their rights and obligations are separate and not joint.

The principal terms and conditions relating to the Company's sale of electric services to Kenergy for resale to the Smelters are set forth in six agreements, three with respect to service to each Smelter. The basic structure of the sale of electric services is that the Company sells the electric services to Kenergy and then Kenergy in turns sells those electric services to each Smelter. Because the Smelters are customers of Kenergy, Big Rivers has entered into two, separate wholesale service agreements (each a "Smelter Agreement") with Kenergy. Under each Smelter Agreement, the Company supplies Kenergy with electric service for resale to a particular Smelter. Kenergy has entered into a separate retail electric service agreement (a "Smelter Retail Agreement") with each Smelter. The Company and each Smelter have also entered into a Smelter Coordination Agreement (a "Smelter Coordination Agreement" and, together with the Smelter Agreements and the Smelter Retail Agreements, the "Smelter Agreements") that sets forth certain direct obligations between the Company and a Smelter. Due to the pass-through nature of the principal obligations between the Company and each Smelter, the Smelter Agreement and the Smelter Retail Agreement relating to each Smelter are substantially the same.

The aggregate amount of energy made available to the Smelters under the Smelter Retail Agreements consists of three types of energy referred to as (1) Base Monthly Energy, (2) Supplemental Energy and (3) Back-Up Energy. "Base Monthly Energy" is 368 MW per hour for Alcan and 482 MW per hour for Century. See APPENDIX D – "SUMMARY OF CERTAIN PROVISIONS OF THE SMELTER AGREEMENTS – Nature of Service."

The obligation of Kenergy to supply electric service to the Smelters pursuant to the Smelter Retail Agreements will terminate on December 31, 2023, unless terminated earlier pursuant to the terms thereof. A Smelter may terminate its Smelter Retail Agreement upon not less than one year's prior written notice of such termination to Kenergy and the Company if such Smelter ceases all smelting operations in Kenergy's service territory. See APPENDIX D – "SUMMARY OF CERTAIN PROVISIONS OF THE SMELTER AGREEMENTS – Termination Rights."

Pricing under the Smelter Agreements is designed so that the Base Rate for the Smelters will always be at least the rate charged to large direct-served industrial customers having an equivalent load factor, plus $.25 per MWh. The contracts provide that the Smelters are obligated to pay various surcharges, including fuel adjustment surcharges and environmental surcharges. In addition, the Smelter Agreements provide for annual adjustments to rates designed to assist the Company in achieving positive margins in each year. See APPENDIX D – "SUMMARY OF CERTAIN PROVISIONS OF THE SMELTER AGREEMENTS – Smelter Payment Obligations."

The Smelters intervened in the Company's last rate case, and pressed their case by saying that keeping the Smelter rates low and predictable was important to reduce the risk that the Smelters would have to cease operations upon the next downward cycle in the world price of aluminum. The Smelters say that they are very sensitive to the price they pay for electricity because the cost of electricity is approximately one-third of the cost of the aluminum smelting process.

Although the KPSC's November 17, 2011, Order in the rate case did not give the Company the full amount of the rate increase it sought, the Smelters have since been lobbying state government in Kentucky for financial relief to enhance the financial viability of their respective Kentucky operations. The Smelters have made public statements that the unanticipated magnitude of the current and future rate increases projected by Big Rivers as well as Big Rivers' recent evaluation of the impact of environmental legislation is what drives the current need for a statewide solution to the Smelters' increasing utility costs. Local representatives of Alcan informed economic development officials in state government in February of this year that projected power rates in 2013-2015 make it difficult for Alcan to envision a long-term future for the Sebree plant. Alcan said that a power rate of $26-$28/MWh would generally ensure that the Sebree smelter remains profitable during a periodic downturn in the London Metals Exchange ("LME") price, and would ensure continued operation for the foreseeable future. They say that without relief their Sebree smelter cannot sustain the next downturn in the world price of aluminum.

At the same time Century informed the same officials that for the immediate future, a rate averaging about $34/MWh from mid-2012 through 2015 would be a competitive rate for its Hawesville smelter. Local representatives of Century have told Big Rivers and others in state government that rates at the status quo level are not sustainable for Century's Hawesville smelter even in the short term, and that $50/MWh power puts their smelter's viability at great risk. Century wrote Big Rivers on April 18, 2012, stating that at the current LME prices the Hawesville aluminum smelter cannot sustain operations at Big Rivers' current and projected power rates, and requesting to renegotiate the power rate provisions of its contract. Big Rivers has commenced discussions with Century relating to the sustainability of the Hawesville smelter. Century reported on April 24, 2012, that with the current power price forecast and assuming that the LME remains at its current level, the Hawesville plant is not viable from an economic standpoint. Century publicly stated that the future of the Hawesville smelter would be discussed by Century's Board of directors at its late June meeting. This meeting has taken place and the Company is not aware of what actions, if any, were taken by Century's Board relating to the Hawesville smelter.

The Smelters have been pursuing projects that they say improve the profitability of their respective facilities. Century completed the restart of a fifth potline in 2011. Alcan completed a $50 million bake furnace project, and announced in February 2012 that it is undertaking a $20 million project to boost electric amperage and produce greater volumes of aluminum. Alcan has also reached agreement with Kenergy and Big Rivers to purchase an additional 10 MW of energy for the one year period beginning July 1, 2012, through June 30, 2013.

Alcan announced in October of 2011 that it had put 13 of its smelter operations worldwide on the block for potential sale. The Sebree smelter was included on the list. According to the Alcan release, there is no timeline for any of these sales to occur.

On June 14, 2012, at the request of the Governor of Kentucky, representatives of the Commonwealth met with representatives of Big Rivers and the Smelters to discuss ways to reduce the Smelters' costs in order to make them more economically viable. A number of approaches were discussed including, but not limited to, suggestions that Big Rivers reduce rates to the Smelters to a rate averaging about $35/MWh. Any reduction in the rates to the Smelters would involve an increase in the rates for other industrial customers and rural customers. The discussions that took place on June 14 were preliminary and will be followed by further exploratory discussions in the near future. Any reduction in the rates charged by Big Rivers to the Smelters and concomitant increase in the rates charged to other customers would require action by the Board of Big Rivers and by the KPSC, among others. In addition, it would likely result in renegotiation of the Smelter Agreements. Other approaches that have been advanced include allowing the Smelters more freedom in purchases from other sources and termination of the Smelter Agreements.

Since the meeting on June 14th, the Smelters have advanced other proposals to Big Rivers requesting significant rate reductions for the Smelters. Big Rivers offered a counterproposal and it has been rejected by the Smelters. On June 25, 2012, Big Rivers advised the Smelters that the gap between their demand and the Big Rivers' proposal is far larger than Big Rivers has the ability to close. There can be no assurances as to the outcome of this situation and as to whether one or both of the Smelters will give one year's notice, terminate its Smelter Agreement and close its smelting operations. Also, on July 8, 2012 Century informed Big Rivers that it was hiring a consultant to evaluate the available transmission capacity, potential congestion, and potential voltage stability issues if the Hawesville plant were to import power for its entire load into Big Rivers' system under a variety of operational scenarios of Big Rivers' generation. Big Rivers can give no assurances as to the outcome of this development.

For a more detailed summary of the provisions of the Smelter Agreements, see APPENDIX D – "SUMMARY OF CERTAIN PROVISIONS OF THE SMELTER AGREEMENTS."

POWER SUPPLY PLANNING

Every other year Big Rivers prepares load forecasts for the three Members. These individual forecasts serve as the basis for Big Rivers' load forecast, which is filed with the RUS. The last load forecast was prepared and filed in 2011. Additionally, every three years an Integrated Resource Plan ("IRP") is prepared in accordance with Kentucky Administrative Rule 807 KAR 5:5058 and filed with the KPSC. The last IRP was filed with the KPSC in November 2010. The next IRP will be filed with the KPSC in 2013. Both of these studies examine a future time frame of 15 years.

GENERATION AND TRANSMISSION ASSETS

Generation Resources

General

The following table sets forth certain information about the Company's owned generating facilities and Station Two.

Generating Facility	Type of Fuel	Net Capacity[2] (MW)	Big Rivers' Entitlement Share (MW)	Commercial Operation Date
Kenneth C. Coleman Plant				
Unit 1	Coal	150	150	1969
Unit 2	Coal	138	138	1970
Unit 3	Coal	155	155	1972
Robert D. Green Plant				
Unit 1	Coal	231	231	1979
Unit 2	Coal	223	223	1981
Robert A. Reid Plant				
Unit 1	Coal	65	65	1966
Combustion Turbine	Oil-Natural Gas	65	65	1976
D.B. Wilson Plant Unit No. 1	Coal	417	417	1986
Station Two Facility Units No. 1 and No. 2[1]	Coal	312	197	1973/1974
Total		1,756	1,641	

(1) Big Rivers operates but does not own the two units at Station Two and not all net capacity of such facility is available to it

(2) Net capacity means net nameplate as adjusted for parasitic load

Kenneth C. Coleman Plant

The Coleman Plant is a three unit, coal-fired steam electric generating unit located near Hawesville, Kentucky. Each of the units has a turbine nameplate rating of 160 MW. Units No. 1 has a net capacity of 150 MW, No. 2 has a net nameplate capacity of 138 MW while Unit No. 3 has a net capacity of 155 MW. All three boilers are positive pressure, outdoor units; the turbine generators are semi-outdoor and the station was retrofitted with a FGD system in 2007. The equivalent availability factor for the Coleman Plant for 2011 was 92.9%.

Environmental controls in place at the Coleman Plant include the use of precipitators (air pollution control devices that collect particles from gaseous emissions) which limit particulate emissions to a maximum of 0.27 pounds per million British thermal unit ("Btu"), and the use of a FGD system which is 97% effective in reducing SO_2 emissions. Coleman Plant's permitted SO_2 emissions limit is a maximum of 5.2 pounds per million Btu. The Coleman Units do not have a Title V permit NO_x limit.

Robert D. Green Plant

The Green Plant is a two unit, coal-fired steam electric generating station located on the same site as the Reid Plant and the Station Two Facility described below. Both boilers at the Green Plant are balanced draft units and they were designed and built with low NO_x burners. The Green Plant is also equipped with a FGD system. Unit No. 1 has a net nameplate capacity of 231 MW while Unit No. 2 has a net capacity of 223 MW. The equivalent availability factor for the Green Plant for 2011 was 94.4%.

Environmental controls in place at the Green Plant include the use of precipitators which limit particulate emissions to a maximum of 0.1 pounds per million Btu, and the use of a FGD system which limits SO_2 emissions to a maximum of 0.8 pounds per million Btu. NO_x emissions are limited to a maximum of 0.7 pounds per million Btu.

Robert A. Reid Plant

The Reid Plant, located near Sebree, Kentucky, is a coal-fired steam electric generating unit with a net capacity of 65 MW and an oil- or natural gas-fired combustion turbine generating unit with a net capacity of 65 MW. The combustion turbine is used for power emergencies and for peaking purposes. The equivalent availability factor for the Reid Plant for 2011 was 92.6%.

Environmental controls in place at the Reid Plant include the use of precipitators which limit particulate emissions to a maximum of 0.28 pounds per million Btu, and the use of medium-sulfur coal which limit SO_2 emissions to a maximum of 5.2 pounds per million Btu. The Reid unit does not have a Title V permit NO_x limit.

D.B. Wilson Unit No. 1 Plant

The single unit Wilson Plant is the largest and newest generating unit in the Company's system. The Wilson Plant, located near Centertown, Kentucky on the Green River, is a coal-fired, balanced draft steam electric generating unit equipped with a FGD system. The unit has a net nameplate capacity of 417 MW. The equivalent availability factor for the Wilson Plant for 2011 was 94.8%.

Environmental controls in place at the Wilson Plant include the use of a precipitator which limits particulate emissions to a maximum of 0.03 pounds per million Btu, and the use of a FGD system which is 90% effective in removing SO_2 emissions. NO_x emissions are limited to a maximum of 0.6 pounds per million Btu.

Other Power Supply Resources

Station Two Facility

The two units at Station Two have a total net nameplate capacity of 312 MW. Station Two is located on the same site as the Reid Plant and the Green Plant, near Henderson. Station Two consists of two positive pressure outdoor type boilers with scrubbers installed. The equivalent availability factor for Station Two for 2011 was 89.8%.

In connection with the Unwind, in July 2009, the Company became responsible for the operation of Station Two in accordance with the terms of the Station Two Operation Agreement and for purchase of capacity and energy in accordance with the terms of the Station Two Power Sales Contract. (See "Station Two Power Sales Contract"). In connection with the Unwind, the Company and WKEC entered into an Indemnification Agreement under which WKEC has agreed to indemnify the Company against potential lost revenue if the contract provisions of the Station Two Power Sales Contract are interpreted against the Company (See "Station Two Power Sales Contract").

Station Two Operation Agreement

The Company operates Station Two in accordance with the Station Two Operation Agreement. The Station Two Operation Agreement provides that the Company will provide, as an independent contractor, all operating personnel, materials, supplies and technical services for the operation of Station Two. It also provides for the allocation of certain costs of operation and maintenance between Station Two and the Company's Reid Plant which shares some common facilities with Station Two. The Station Two Operation Agreement provides that the Company prepares an operating budget, including both capital and operating expenditures, for Station Two which is subject to the approval of the City of Henderson. Such budget then becomes the basis for monthly payments by the City of Henderson to the Company, with an annual reconciliation of such budgeted expenditures and the actual annual expenditures for Station Two. The Station Two Operation Agreement obligates the Company to maintain property and liability insurance with respect to Station Two and to operate and maintain Station Two in accordance with standards and specifications equal to those provided by the National Electric Safety Code of the United States Bureau of Standards and well as those required by any regulatory authority having jurisdiction. Each party's obligations under the Station Two Operation Agreement are subject to the occurrence of "uncontrollable force" (*e.g.*, events not within control of either party and which by exercise of due diligence and foresight could not reasonably be avoided). The obligations of the City of Henderson under the Station Two Operation Agreement are payable solely from the revenues of the City's electric utility system and do not constitute a general obligation of the City of Henderson. The City of Henderson has covenanted in the Station Two Operation Agreement that it will, subject to any necessary regulatory body approvals, maintain rates for service by its electric system sufficient to pay the costs of ownership, proper operation and maintenance of Station Two. The rates for electric service charged by the City of Henderson are not subject to any regulatory body approval. The term of the Station Two Operation Agreement extends for the operating life of Station Two.

Station Two Power Sales Contract

The Company purchases a portion of the power and energy produced by Station Two in accordance with a Power Sales Contract between the City of Henderson and the Company (the "Station Two Power Sales Contract"). The Station Two Power Sales Contract provides for the allocation of the capacity of Station Two between the City of Henderson and the Company based upon the City's determination of its needs to serve its retail customers. The Station Two Power Sales Contract requires the City of Henderson to give the Company a rolling five years' advance notice of the allocation of capacity between the City of Henderson and the Company, but changes of up to 5 MW in the City's allocation are permitted on a yearly basis. The Station Two Power Sales Contract limits the ability of the City of Henderson to add commercial or industrial customers in excess of 30 MW each to its system if to do so would require the withdrawal of existing capacity from Station Two or any other generating facilities on the City's existing electrical system. The Station Two Power Sales Contract also permits the City of Henderson to utilize up to a total of 25 MW of capacity from capacity otherwise allocated to the Company from Station Two for "economic development loads" consisting of new customers on the City's system or certain expansions of capacity by an existing customer. The Company's right to take its reserved portion of the capacity of Station Two is subject to the City of Henderson's prior right to take its allocated capacity. Thus, in the event of an outage or curtailment of the output of Station Two, the City's right to the output has a priority. Each party is entitled to all the energy from Station Two associated with its reserved capacity, subject to the Company's right to "Excess Henderson Energy" described below. The current capacity allocations of the City of Henderson and the Company effective June 1, 2012, are 37% and 63%, respectively.

The Company and the City of Henderson share capacity costs for Station Two in accordance with each party's respective allocated capacities. These capacity costs include the costs of operation, maintenance, administration and general expenses for Station Two as well as any amounts paid or payable to the Company under the terms of the Station Two Operation Agreement. The Company and the City of Henderson are each responsible for providing their respective portions of the fuel consumed by Station Two based on each party's respective uses of electric energy from Station Two.

The obligations of each party are subject to "uncontrollable force", having the same definition as in the Station Two Operation Agreement. However, the Company's obligation to make payments for its allocated capacity of Station Two is not excused for any reason including the occurrence of "uncontrollable force".

The Station Two Power Sales Contract permits the City of Henderson to terminate that agreement on 30 days' notice for the Company's failure to make any payment properly owing under the Station Two Power Sales Contract and, in such event, to make sales to others of power generated by Station Two and allocated to the Company on 5 days' notice to the Company and to apply the proceeds of such sales to the capacity charges the Company owes.

In accordance with the Station Two Power Sales Contract, the Company and the City of Henderson have established separate operation and maintenance funds in the amounts of $400,000 and $100,000, respectively, to fund expenditures for operation and maintenance for Station Two, such expenditures to be made from such funds in proportion to the then effective allocation of Station Two capacity between the Company and the City of Henderson. In accordance with the Station Two Power Sales Contract, the Company has agreed to fund up to $1.05 million to fund its portion of major renewals or replacements to the Station Two required on an emergency basis.

The term of the Station Two Power Sales Contract extends through the end of the economic operating life of Station Two.

Excess Henderson Energy

Big Rivers and the City of Henderson are engaged in an arbitration proceeding regarding their respective rights under the Station Two Power Sales Contract to energy associated with the City of Henderson's reserved capacity that the City of Henderson does not require for service to its native load. Big Rivers' position is that, to the extent the City of Henderson does not take the full amount of energy associated with its reserved capacity from Station Two (such excess, "Excess Henderson Energy"), Big Rivers may take and utilize all such energy for a price of $1.50 per MWh plus the cost of all fuel, reagent and sludge disposal costs associated with such Excess Henderson Energy. Big Rivers further asserts that the Station Two Power Sales Contract precludes the City of Henderson from offering Excess Henderson Energy to a third party without first offering Big Rivers the opportunity to purchase in accordance with the preceding sentence. The City of Henderson alleges that the Station Two Power Sales Contract permits the City to schedule and take energy from its allocated capacity of Station Two, and sell it to third parties after first offering such energy to Big Rivers at the price a third party is willing to pay. The arbitration panel issued its award on May 31, 2012, finding, among other things, that the disputed "excess energy shall be considered to belong to [the City of Henderson] which it may offer to third parties subject to Big Rivers first right to purchase such energy" at "the price at which [the City of Henderson] has a firm offer from a third party." On June 26, 2012, attorneys for the City of Henderson placed a demand on Big Rivers for the amount of $3,753,013.09, which, they allege, represents the amount of fixed costs associated with Excess Henderson Energy from August 2009 to May 30, 2012 minus a credit to Big Rivers for the $1.50 for each MWh taken. Big Rivers and its counsel are still analyzing the implications of the award, Big Rivers' options under the circumstances and the recent demand letter from the City of Henderson. In addition, as described above under the caption "*Station Two Facility*", WKEC and Big

Rivers have entered into an Indemnification Agreement relating to the Station Two Power Sales Contract and Big Rivers understands that WKEC and its counsel are also analyzing the implications of the award, WKEC's option under the circumstances and the recent demand letter from the City of Henderson.

SEPA Contract

In addition to the Company's generation resources, the Company fulfills its power supply responsibilities to the Members with their allocations from SEPA. The Company normally uses entitlement under the SEPA Contract for peaking. However, as a result of problems with certain dams on the Cumberland River hydro system, the Company's capacity entitlement has been suspended and it currently is receiving only energy. Generally, the Company must schedule and accept 1,500 hours of the contracted 178 MW each fiscal year ending June 30. The maximum amount scheduled in any month shall not exceed 240 hours and the minimum amount scheduled in any month shall not be less than 60 hours. The fee arrangement for generation is a take-or-pay contract, currently the Company pays a fixed monthly charge in the amount of approximately $260,937 and $17.69 per MWh for energy. These charges will continue until the dam work is completed and the SEPA Contract is restored to full service. SEPA cannot give notice of termination prior to October 1, 2029, with an effective date of September 30, 2032.

Transmission

In December 2010, the Company transferred functional control of its transmission system operated at 100 kV and above to MISO. In addition to operating the bulk transmission system of its participants, MISO also operates the MISO Market. In the MISO Market, the Company and other participants submit day-ahead or real-time bids and offers for the purchase or sale of energy at various locations. MISO then directs each MISO Market participant whether to operate its generation facilities and determines the price of energy at each location for a particular time period. The Company operates and maintains its transmission facilities and provides transmission services to the Members and Non-Members through MISO. As of December 31, 2011, the Company had in service 834 miles of 69 kV transmission lines, 14 miles of 138 kV transmission lines, 350 miles of 161 kV transmission lines and 68 miles of 345 kV transmission lines. The Company also owns 22 substations. The Company has completed or substantially completed six of the seven system improvements identified as phase two transmission projects. The Company has a construction work agreement with the TVA whereby TVA will pursue the completion of the one remaining project. The Company's available transfer capability for exporting power off system is approximately 1,202 MW with the completion of the six phase two transmission improvements. The current firm transmission capability is sufficient to allow the Company to export all available excess generation capacity plus an amount equal to the peak demand of both Smelters on its system. With the completion of the TVA construction projects currently estimated to be in 2014-2015, the Company's export capability will be increased to approximately 1,263 MW to TVA and 1,210 MW to MISO in 2016.

Southeastern Electric Reliability Council ("SERC") Investigation

Big Rivers is currently the subject of a non-public investigation initiated by SERC in February 2009. The staff from NERC and FERC also participated in the investigation. In June 2011, SERC initiated a formal assessment to determine the Company's compliance relative to eight reliability standards and requirements as a result of findings of possible violations by the investigation team. Aside from one minor instance, which has been disclosed to SERC, Big Rivers believes that it has been, and is, in compliance with all reliability standards and requirements. However, penalties for violations of reliability standards can be substantial. SERC recently has determined that two of the eight possible violations are not violations. At this time the assessment is still ongoing and the Company cannot estimate the amount or range of potential liability, if any.

Interconnections

Big Rivers has several interconnections between its transmission system and those of other power suppliers. These interconnections permit mutual support in emergencies, decrease overall transmission losses, facilitate the arrangement of electric power and energy sales and minimize the duplication of transmission lines. Big Rivers currently has interconnection agreements with seven power suppliers: HMP&L, MISO, Southern Illinois Power Cooperative, Hoosier Energy Rural Electric Cooperative, and Southern Indiana Gas and Electric Company – Vectren, Kentucky Utilities Company and Louisville Gas and Electric Company, and TVA. However, Big Rivers cannot purchase power from TVA due to restrictions on TVA's authority to sell power outside of its service area fixed by statute. An agreement with TVA provides transmission service by TVA to enable Big Rivers to interchange power and energy with four utilities located in the southern United States.

In addition to interconnections with neighboring transmission systems, Big Rivers has also received a request from an independent power producer that may locate within its local balancing area and interconnect new generators to the transmission system. This independent power producer has applied through MISO to connect to Big Rivers' transmission facilities. MISO worked with Big Rivers to study the impacts of such interconnection and to identify the cost of accommodating the interconnection. This generation interconnection will be effectuated through a standard-form, three-way interconnection agreement among Big Rivers, MISO and the independent power producer seeking use of MISO's transmission service.

Open Access Transmission Tariff

Effective December 2010 the use of the Company's transmission facilities is governed by the MISO Tariff. The Company provides the MISO with its revenue requirement for use in establishing the rate for transmission services under the MISO Tariff, but such revenue requirement is not directly reviewed by FERC. As a MISO transmission owner, the Company also participates in the MISO transmission planning process, and is responsible for investments in transmission projects assigned to it in accordance with that process. Participation in the MISO transmission planning process increases the scope of the Company's regional planning process and subjects it to decisions by the MISO and, ultimately, FERC, concerning allocations of costs for meeting regional transmission needs. Finally, the Company is subject to the MISO reserve requirements established pursuant to Module E of the MISO Tariff.

MANAGEMENT

Big Rivers is governed by a Board of Directors comprised of six persons. Each Member has two directors on the Board of Directors. Each director is elected by a majority vote of the delegates at the annual membership meeting in September. Each Member designates one delegate to represent it at the annual membership meeting. At least one of the two directors from each Member must be, at the time of their election, a director of such Member. Each term is for a three year period, ending the later of September 1 or the annual meeting date, and staggered such that two directors from different Members are elected each year.

The following are the Company's principal management personnel with a brief summary of their qualifications:

Mark A. Bailey, President and Chief Executive Officer, received a Bachelor of Science in Electrical Engineering from Ohio Northern University in 1974, and a Master of Science in Management from the Massachusetts Institute of Technology in 1988. He was employed by American Electric Power Company ("AEP") for nearly 30 years, beginning as an Electrical Engineer in 1974. Mr. Bailey was employed as Vice President of AEP subsidiary Indiana Michigan Power Company until AEP's reorganization in 1996, when he became Director-Regions with American Electric Power Service Corporation ("AEPSC"), also a subsidiary of AEP. He was employed as Vice President of Transmission Asset Management for AEPSC from June 2000 until his employment as President and Chief Executive Officer with Kenergy Corp. in 2004. Mr. Bailey was employed as Executive Vice President and Chief Operating Officer beginning in June 2007 until being elected by the Board of Directors to his current position in October 2008.

Robert W. Berry, Vice President of Production, graduated from the University of Kentucky Community College system with an Associate degree in Mechanical Engineering Technology and Mid-Continent University with a Bachelor of Science in Business Management. He was employed by Big Rivers from 1981 to 1998 and served in various maintenance positions such as Superintendent of Maintenance and Maintenance Manager. In 1998 he was employed by Western Kentucky Energy and served in various positions such as Maintenance Manager, Plant Manager and General Manager until the Unwind transaction closed in July 2009, at which time he assumed his current position.

David G. Crockett, Vice President of System Operations, graduated from the University of Kentucky with a Bachelor of Science in Electrical Engineering in 1972. He has been employed with Big Rivers since 1972. He served in various engineering positions before assuming the responsibility of Manager of Energy Control in 1998. Mr. Crockett assumed his current position as Vice President System Operations in 2006.

James V. Haner, Vice President of Administrative Services, graduated from the University of Kentucky with a Bachelor of Science in Accounting in 1970. He has been employed with Big Rivers since 1972. He served in various accounting and finance capacities prior to transferring to administrative services in 1991. He assumed duties as Manager Human Resources in 1998. Mr. Haner assumed his current position of Vice President Administrative Services in 2005.

Mark A. Hite, Vice President of Accounting and Interim Chief Financial Officer, graduated from the University of Evansville with a Bachelor of Science in Accounting in 1980 and a Master of Business Administration in 1985. He is a licensed CPA. Mr. Hite has been employed with Big Rivers since 1983, and has served in various accounting and finance capacities prior to assuming his current position of Vice President of Accounting. He was appointed Interim Chief Financial Officer in 2012.

Eric M. Robeson, Vice President of Environmental Services and Construction, graduated from Rose Hulman Institute of Technology in 1977 with a Bachelor of Science in Mechanical Engineering and Ball State University in 1988 with a Masters of Business Administration. He is a registered Professional Engineer in the state of Indiana. Mr. Robeson worked at Vectren (and its predecessor company Sigeco) from 1980 to 2011. He served a variety of engineering and managerial positions including Plant Manager, Director of Generation Planning, and Director of Infrastructure Services. He joined Big Rivers in 2011 as Vice President of Construction overseeing environmental compliance efforts and assumed his current position in February 2012.

Albert M. Yockey, Vice President of Governmental Relations & Enterprise Risk Management, graduated from the University of Pittsburgh with a Bachelor of Science in Electrical Engineering in 1972, a Master of Science from Lehigh University in 1979, and a Juris Doctor from Capital University Law School in 1994. He is a licensed attorney in Ohio. Mr. Yockey was employed in operation and planning positions with Pennsylvania Power and Light Co. from 1972 through 1985. He was employed in planning, regulatory, and compliance positions with American Electric Power Company from 1985 until February 2008. Mr. Yockey joined Big Rivers as Vice President of Enterprise Risk Management and Strategic Planning in 2008 and assumed his current position in July 2009.

Big Rivers has 627 full-time employees. The International Brotherhood of Electrical Workers, Local 1701, represents 371 of Big Rivers' generation and transmission operating employees. The Company's contracts with this union expire on September 14, 2012, and October 14, 2012, respectively. The Company believes that its relations with labor are good.

APPENDIX A

YEAR END FINANCIAL STATEMENTS

KPMG

BIG RIVERS ELECTRIC CORPORATION

Financial Statements

December 31, 2011 and 2010

(With Independent Auditors' Report Thereon)

KPMG

KPMG LLP
1601 Market Street
Philadelphia, PA 19103-2499

Independent Auditors' Report

The Board of Directors and Members
Big Rivers Electric Corporation:

We have audited the accompanying balance sheets of Big Rivers Electric Corporation (the Company) as of December 31, 2011 and 2010, and the related statements of operations, equities, and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. The accompanying financial statements of the Company for the year ended December 31, 2009 were audited by other auditors whose report thereon dated March 26, 2010, expressed an unqualified opinion on those statements.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America and the standards applicable to financial audits contained in *Government Auditing Standards*, issued by the Comptroller General of the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Big Rivers Electric Corporation as of December 31, 2011 and 2010, and the results of its operations and its cash flows for the years then ended, in conformity with accounting principles generally accepted in the United States of America.

In accordance with *Government Auditing Standards*, we have also issued a report dated March 26, 2012, on our consideration of Big Rivers Electric Corporation's internal control over financial reporting and our tests of its compliance with certain provisions of laws, regulations, contracts, and grant agreements and other matters. The purpose of that report is to describe the scope of our testing of internal control over financial reporting and compliance and the results of that testing, and not to provide an opinion on the internal control over financial reporting or on compliance. That report is an integral part of an audit performed in accordance with *Government Auditing Standards* and should be read in conjunction with this report in considering the results of our audits.

KPMG LLP

March 26, 2012

BIG RIVERS ELECTRIC CORPORATION

Balance Sheets

December 31, 2011 and 2010

(Dollars in thousands)

Assets	**2011**	**2010**
Utility plant – net	$ 1,092,063	$ 1,091,566
Restricted investments – member rate mitigation	163,162	217,562
Other deposits and investments – at cost	5,911	5,473
Current assets:		
Cash and cash equivalents	44,849	44,780
Accounts receivable	44,287	45,905
Fuel inventory	33,894	37,328
Nonfuel inventory	25,295	23,218
Prepaid expenses	4,217	2,502
Total current assets	152,542	153,733
Deferred charges and other	4,244	3,851
Total	$ 1,417,922	$ 1,472,185
Equities and Liabilities		
Capitalization:		
Equities	$ 389,820	$ 386,575
Long-term debt	714,254	809,623
Total capitalization	1,104,074	1,196,198
Current liabilities:		
Current maturities of long-term obligations	72,145	7,373
Notes payable	—	10,000
Purchased power payable	1,878	1,516
Accounts payable	28,446	29,782
Accrued expenses	10,380	10,627
Accrued interest	9,899	11,134
Total current liabilities	122,748	70,432
Deferred credits and other:		
Regulatory liabilities – member rate mitigation	169,001	185,893
Other	22,099	19,662
Total deferred credits and other	191,100	205,555
Commitments and contingencies (see note 14)		
Total	$ 1,417,922	$ 1,472,185

See accompanying notes to financial statements.

BIG RIVERS ELECTRIC CORPORATION

Statements of Operations

Years ended December 31, 2011, 2010, and 2009

(Dollars in thousands)

	2011	2010	2009
Operating revenue	$ 561,989	$ 527,324	$ 341,333
Lease revenue	—	—	32,027
Total operating revenue	561,989	527,324	373,360
Operating expenses:			
Operations:			
Fuel for electric generation	226,229	207,749	80,655
Power purchased and interchanged	112,262	99,421	116,883
Production, excluding fuel	50,410	52,507	22,381
Transmission and other	39,085	35,273	35,444
Maintenance	47,718	46,880	29,820
Depreciation and amortization	35,407	34,242	32,485
Total operating expenses	511,111	476,072	317,668
Electric operating margin	50,878	51,252	55,692
Interest expense and other:			
Interest	45,226	46,570	59,898
Amortization of loss from termination of long-term lease	—	—	2,172
Income tax expense	100	259	1,025
Other – net	220	166	112
Total interest expense and other	45,546	46,995	63,207
Operating margin	5,332	4,257	(7,515)
Nonoperating margin:			
Gain on unwind transaction (see note 2)	—	—	537,978
Interest income and other	268	2,734	867
Total nonoperating margin	268	2,734	538,845
Net margin	$ 5,600	$ 6,991	$ 531,330

See accompanying notes to financial statements.

BIG RIVERS ELECTRIC CORPORATION

Statements of Equities (Deficit)

Years ended December 31, 2011, 2010, and 2009

(Dollars in thousands)

	Total equities (deficit)	Accumulated margin (deficit)	Other equities: Donated capital and memberships	Other equities: Consumers' contributions to debt service	Accumulated other comprehensive income
Balance – December 31, 2008	$ (154,602)	$ (146,823)	$ 764	$ 3,681	$ (12,224)
Comprehensive income:					
Net margin	531,330	531,330	—	—	—
Defined benefit plans	2,664	—	—	—	2,664
Total comprehensive income	533,994	531,330	—	—	2,664
Balance – December 31, 2009	379,392	384,507	764	3,681	(9,560)
Comprehensive income:					
Net margin	6,991	6,991	—	—	—
Defined benefit plans	192	—	—	—	192
Total comprehensive income	7,183	6,991	—	—	192
Balance – December 31, 2010	386,575	391,498	764	3,681	(9,368)
Comprehensive income:					
Net margin	5,600	5,600			
Defined benefit plans	(2,355)				(2,355)
Total comprehensive income	3,245	5,600	—	—	(2,355)
Balance – December 31, 2011	$ 389,820	$ 397,098	$ 764	$ 3,681	$ (11,723)

See accompanying notes to financial statements.

BIG RIVERS ELECTRIC CORPORATION

Statements of Cash Flows

Years ended December 31, 2011, 2010, and 2009

(Dollars in thousands)

	2011	2010	2009
Cash flows from operating activities:			
Net margin	$ 5,600	$ 6,991	$ 531,330
Adjustments to reconcile net margin to net cash provided by operating activities:			
Depreciation and amortization	37,808	37,650	37,084
Amortization of deferred loss (gain) on sale-leaseback – net	—	—	2,172
Deferred lease revenue	—	—	(3,768)
Residual value payments obligation gain	—	—	(3,881)
Interest compounded – RUS Series A Note	8,398	—	—
Interest compounded – RUS Series B Note	6,884	6,499	6,136
Noncash gain on unwind transaction		—	(269,441)
Cash received for member rate mitigation		—	217,856
Noncash member rate mitigation revenue	(18,947)	(23,953)	(12,033)
Changes in certain assets and liabilities:			
Accounts receivable	1,618	1,588	(26,049)
Inventories	1,357	(2,304)	(3,497)
Prepaid expenses	(1,715)	731	(2,783)
Deferred charges	121	1,251	(1,538)
Purchased power payable	362	(1,846)	(5,973)
Accounts payable	(1,336)	(875)	24,825
Accrued expenses	(1,481)	2,800	7,881
Other – net	(70)	555	6,852
Net cash provided by operating activities	38,599	29,087	505,173
Cash flows from investing activities:			
Capital expenditures	(38,746)	(42,683)	(58,388)
Proceeds from restricted investments	56,095	28,143	8,982
Purchases of restricted investments and other deposits and investments		—	(252,798)
Net cash provided by (used in) investing activities	17,349	(14,540)	(302,204)
Cash flows from financing activities:			
Principal payments on long-term obligations	(45,879)	(121,355)	(168,956)
Proceeds from long-term obligations	—	83,300	—
Principal payments on short-term notes payable	(10,000)	—	(12,380)
Proceeds from short-term notes payable	—	10,000	—
Debt issuance cost on bond refunding	—	(2,002)	(246)
Net cash used in financing activities	(55,879)	(30,057)	(181,582)
Net increase (decrease) in cash and cash equivalents	69	(15,510)	21,387
Cash and cash equivalents – beginning of year	44,780	60,290	38,903
Cash and cash equivalents – end of year	$ 44,849	$ 44,780	$ 60,290
Supplemental cash flow information:			
Cash paid for interest	$ 31,441	$ 37,268	$ 51,078
Cash paid for income taxes	130	260	626

See accompanying notes to financial statements.

(1) Organization and Summary of Significant Accounting Policies

(a) *General Information*

Big Rivers Electric Corporation (Big Rivers or the Company), an electric generation and transmission cooperative, supplies wholesale power to its three member distribution cooperatives (Kenergy Corp., Jackson Purchase Energy Corporation, and Meade County Rural Electric Cooperative Corporation) under all requirements contracts, excluding the power needs of two large aluminum smelters (the Aluminum Smelters). Additionally, Big Rivers sells power under separate contracts to Kenergy Corp. for the Aluminum Smelters load and markets power to nonmember utilities and power marketers. The members provide electric power and energy to industrial, residential, and commercial customers located in portions of 22 western Kentucky counties. The wholesale power contracts with the members remain in effect until December 31, 2043. Rates to Big Rivers' members are established by the Kentucky Public Service Commission (KPSC) and are subject to approval by the Rural Utilities Service (RUS). The financial statements of Big Rivers include the provisions of the Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 980, *Certain Types of Regulation*, which was adopted by the Company in 2003, and gives recognition to the ratemaking and accounting practices of the KPSC and RUS.

Management evaluated subsequent events up to and including March 26, 2012, the date the financial statements were available to be issued.

(b) *Principles of Consolidation*

The financial statements of Big Rivers include the accounts of Big Rivers and its wholly owned subsidiary, Big Rivers Leasing Corporation (BRLC). All significant intercompany transactions have been eliminated. BRLC was dissolved July 7, 2009.

(c) *Estimates*

The preparation of the financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and disclosure of contingent assets and liabilities. The estimates and assumptions used in the accompanying financial statements are based upon management's evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results may differ from those estimates.

(d) *System of Accounts*

Big Rivers' maintains its accounting records in accordance with the Uniform System of Accounts as prescribed by the RUS Bulletin 1767B-1, as adopted by the KPSC. These regulatory agencies retain authority and periodically issue orders on various accounting and ratemaking matters. Adjustments to RUS accounting have been made to make the financial statements consistent with generally accepted accounting principles in the United States of America.

(Continued)

(Dollars in thousands)

(e) ***Revenue Recognition***

Revenues generated from the Company's wholesale power contracts are based on month-end meter readings and are recognized as earned. Prior to its termination, in accordance with FASB ASC 840, *Leases*, Big Rivers' revenue from the Lease Agreement was recognized on a straight-line basis over the term of the lease. The major components of this lease revenue include the annual lease payments and the Monthly Margin Payments (described in note 2).

(f) ***Utility Plant and Depreciation***

Utility plant is recorded at original cost, which includes the cost of contracted services, materials, labor, overhead, and an allowance for borrowed funds used during construction. Replacements of depreciable property units, except minor replacements, are charged to utility plant.

Allowance for borrowed funds used during construction is included on projects with an estimated total cost of $250 or more before consideration of such allowance. The interest capitalized is determined by applying the effective rate of Big Rivers' weighted average debt to the accumulated expenditures for qualifying projects included in construction in progress.

Depreciation of utility plant in service is recorded using the straight-line method over the estimated remaining service lives, as approved by the RUS and KPSC. During 2010, the Company commissioned a depreciation study to evaluate the remaining economic lives of its assets. In 2011, the study was completed and approved by the RUS and KPSC. The annual composite depreciation rates used to compute depreciation expense were as follows:

	Jan-Nov 2011	Dec 2011
Electric plant	1.60 – 2.47%	0.50 – 20.22%
Transmission plant	1.76 – 3.24	1.42 – 2.23
General plant	1.11 – 5.62	2.84 – 17.12

For 2011, 2010, and 2009, the average composite depreciation rates were 1.91%, 1.86%, and 1.85%, respectively. At the time plant is disposed of, the original cost plus cost of removal less salvage value of such plant is charged to accumulated depreciation, as required by the RUS.

(g) ***Impairment Review of Long-Lived Assets***

Long-lived assets are reviewed as facts and circumstances indicate that the carrying amount may be impaired. FASB ASC 360, *Property, Plant, and Equipment*, requires the evaluation of impairment by comparing an asset's carrying value to the estimated future cash flows the asset is expected to generate over its remaining life. If this evaluation were to conclude that the future cash flows were not sufficient to recover the carrying value of the asset, an impairment charge would be recorded based on the difference between the asset's carrying amount and its fair value (less costs to sell for assets to be disposed of by sale) as a charge to net margin.

(h) ***Inventory***

Inventories are carried at average cost and include coal, petroleum coke, lime, limestone, oil and gas used for electric generation, and materials and supplies used for utility operations. Emission allowances are carried in inventory at a weighted average cost by each vintage year. Issuances of allowances are accounted for on a vintage basis using a monthly weighted average cost.

(i) ***Restricted Investments***

Investments are restricted under KPSC order to establish certain reserve funds for member rate mitigation in conjunction with the Unwind Transaction. These investments have been classified as held-to-maturity and are carried at amortized cost (see note 9).

(j) ***Cash and Cash Equivalents***

Big Rivers considers all short-term, highly liquid investments with original maturities of three months or less to be cash equivalents.

(k) ***Income Taxes***

Big Rivers was formed as a tax-exempt cooperative organization as described in Internal Revenue Code Section 501(c)(12). To retain tax-exempt status under this section, at least 85% of the Big Rivers' receipts must be generated from transactions with the Company's members. In 1983, sales to nonmembers resulted in Big Rivers failing to meet the 85% requirement. Until Big Rivers can meet the 85% member income requirement, the Company will not be eligible for tax-exempt status and will be treated as a taxable cooperative.

As a taxable cooperative, Big Rivers is entitled to exclude the amount of patronage allocations to members from taxable income. Income and expenses related to non-patronage sourced operations are taxable to Big Rivers. Big Rivers files a federal income tax return and certain state income tax returns.

Under the provisions of FASB ASC 740, *Income Taxes*, Big Rivers is required to record deferred tax assets and liabilities for temporary differences between amounts reported for financial reporting purposes and amounts reported for income tax purposes. Deferred tax assets and liabilities are determined based upon these temporary differences using enacted tax rates for the year in which these differences are expected to reverse. Deferred income tax expense or benefit is based on the change in assets and liabilities from period to period, subject to an ongoing assessment of realization. Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return are recorded only when the more-likely than-not recognition threshold is satisfied and measured at the largest amount of benefit that is greater than 50% likely of being realized upon settlement.

(Continued)

(l) Patronage Capital

As provided in the bylaws, Big Rivers accounts for each year's patronage-sourced income, both operating and nonoperating, on a patronage basis. Notwithstanding any other provision of the bylaws, the amount to be allocated as patronage capital for a given year shall not be less than the greater of regular taxable patronage-sourced income or alternative minimum taxable patronage-sourced income.

(m) Derivatives

Management has reviewed the requirements of FASB ASC 815, *Derivatives and Hedging*, and has determined that certain contracts the Company is party to may meet the definition of a derivative under FASB ASC 815. The Company has elected the Normal Purchase and Normal Sale exception for these contracts and, therefore, the contracts are not required to be recognized at fair value in the financial statements.

(n) Fair Value Measurements

FASB ASC 820, *Fair Value Measurements and Disclosures*, defines fair value as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal, or most advantageous, market for the asset or liability in an orderly transaction between market participants at the measurement date. FASB ASC 820 establishes a three-level fair value hierarchy that prioritizes the inputs used to measure fair value. This hierarchy requires entities to maximize the use of observable inputs when possible. The three levels of inputs used to measure fair value are as follows:

- Level 1 – quoted prices in active markets for identical assets or liabilities;
- Level 2 – observable inputs other than quoted prices included in Level 1, such as quoted prices for similar assets and liabilities in active markets; quoted prices for identical or similar assets and liabilities in markets that are not active; or other inputs that are observable or can be corroborated by observable market data; and
- Level 3 – unobservable inputs that are supported by little or no market activity and that are significant to the fair values of the assets or liabilities, including certain pricing models, discounted cash flow methodologies, and similar techniques that use significant unobservable inputs.

(Dollars in thousands)

(2) LG&E Lease Agreement

Big Rivers, LG&E and KU, Western Kentucky Energy Corporation (WKEC), and LG&E Energy Marketing (LEM), closed effective July 17, 2009, a transaction resulting in a mutually acceptable early termination of the 1998 LG&E Lease Agreement (referred herein as the Unwind Transaction or Unwind). LG&E and KU, WKEC, and LEM are collectively referred to in the notes as "LG&E and KU Entities." This transaction was approved by the KPSC and the RUS. The Unwind Transaction resulted in Big Rivers recognizing a net gain of $537,978. This transaction resulted in the acquisition of assets, the assumption of liabilities, the forgiveness of liabilities, and the establishment of a regulatory reserve prescribed by the KPSC in their approval of the transaction. Assets and liabilities in the unwind transaction were accounted for at fair value or recorded value, as appropriate. The gain from the Unwind Transaction is summarized as follows:

		Unwind gain
Assets received:		
Cash	$	506,675
Coleman scrubber		98,500
Inventory		55,000
Construction in progress		23,074
Utility plant assets		19,679
SO2 allowances		980
Liabilities (assumed) forgiven:		
Economic reserve		(157,000)
Rural economic reserve		(60,856)
Post-retirement benefits liability		(8,768)
Residual value payments obligation		145,251
LEM Settlement Note		15,440
Recognition of (expenses) income:		
Deferred lease income		7,187
Deferred loss from termination of sale/leaseback		(73,829)
Deferred loss from LEM Marketing Payment/Settlement Note		(14,520)
Unwind transaction costs		(18,991)
Other		156
Gain on unwind transaction	$	537,978

The terms of the LG&E Lease Agreement as originally structured are outlined in the following text.

On July 15, 1998 (Effective Date), a lease was consummated (Lease Agreement), whereby Big Rivers leased its generating facilities to Western Kentucky Energy Corporation (WKEC), a wholly owned subsidiary of LG&E and KU. Pursuant to the Lease Agreement, WKEC operated the generating facilities and maintained title to all energy produced. Throughout the lease term, in order for Big Rivers to fulfill its obligation to supply power to its members, the Company purchased substantially all of its power requirements from LG&E Energy Marketing Corporation (LEM), a wholly owned subsidiary of LG&E and KU, pursuant to a power purchase agreement.

Big Rivers continued to operate its transmission facilities and charged LEM tariff rates for delivery of the energy produced by WKEC and consumed by LEM's customers. The significant terms of the Lease Agreement were as follows:

a. WKEC was to lease and operate Big Rivers' generation facilities through 2023.

b. Big Rivers retained ownership of the generation facilities both during and at the end of the lease term.

c. WKEC paid Big Rivers an annual lease payment of $30,965 over the lease term, subject to certain adjustments.

d. On the Effective Date, Big Rivers received $69,100 representing certain closing payments and the first two years of the annual lease payments. In accordance with FASB ASC 840, *Leases*, the Company amortized these payments to revenue on a straight-line basis over the life of the lease.

e. Big Rivers continued to provide power for its members, excluding the member loads serving the Aluminum Smelters, through its power purchase agreements with LEM and the Southeastern Power Administration, based on a pre-determined maximum capacity. When economically feasible, the Company also obtained the power necessary to supply its member loads, excluding the Aluminum Smelters, in the open market. Kenergy Corp.'s retail service for the Aluminum Smelters was served by LEM and other third-party providers that included Big Rivers. To the extent the power purchased from LEM did not reach pre-determined minimums, the Company was required to pay certain penalties. Also, to the extent additional power was available to Big Rivers under the LEM contract, Big Rivers made sales to nonmembers.

f. LEM reimbursed Big Rivers the margins expected from the Aluminum Smelters, defined as the net cash flows that Big Rivers anticipated receiving if the Company had continued to serve the Aluminum Smelters' load, as filed in the Rate Hearing (the Monthly Margin Payments).

g. WKEC was responsible for the operating costs of the generation facilities; however, Big Rivers was partially responsible for ordinary capital expenditures (Nonincremental Capital Costs) for the generation facilities over the term of the Lease Agreement, generally up to predetermined annual amounts. At the end of the lease term, Big Rivers was obligated to fund a "Residual Value Payment" to LG&E and KU for such capital additions during the lease (see note 1). Adjustments to the Residual Value Payment were made based upon actual capital expenditures. Additionally, WKEC made required capital improvements to the facilities to comply with new laws or changes to existing laws (Incremental Capital Costs) over the lease life (the Company was partially responsible for such costs—20% prior to termination of the lease) and the Company was required to submit another Residual Value Payment to LG&E and KU for the undepreciated value of WKEC's 80% share of these costs, at the end of the lease. The Company had title to these assets during the lease and upon lease termination.

h. Big Rivers entered into a note payable with LEM for $19,676 (the LEM Settlement Note) to be repaid over the term of the Lease Agreement, with an interest rate at 8% per annum, in consideration for LEM's assumption of the risk related to unforeseen costs with respect to power to be supplied to the Aluminum Smelters and the increased responsibility for financing capital improvements. The Company recorded this obligation as a component of deferred charges with the related payable recorded as long-term debt in the accompanying balance sheets. This deferred charge was amortized on a straight-line basis up to the Effective Date of the Unwind Transaction.

i. On the Effective Date, Big Rivers paid a nonrefundable marketing payment of $5,933 to LEM, which was recorded as a component of deferred charges. This amount was amortized on a straight-line basis up to the Effective Date of the Unwind Transaction.

j. During the lease term, Big Rivers was entitled to certain "billing credits" against amounts the Company owed LEM under the power purchase agreement. Each month during the first 55 months of the lease term, Big Rivers received a credit of $89. For the year 2011, Big Rivers was to receive a credit of $2,611 and for the years 2012 through 2023, the Company was to receive a credit of $4,111 annually.

In accordance with the power purchase agreement with LEM, the Company was allowed to purchase power in the open market rather than from LEM, incurring penalties when the power purchased from LEM did not meet certain minimum levels, and to sell excess power (power not needed to supply its jurisdictional load) in the open market (collectively referred to as Arbitrage). Pursuant to the New RUS Promissory Note (currently the RUS Series A Note) and the RUS ARVP Note (currently the RUS Series B Note), the benefit, net of tax, as defined, derived from Arbitrage had to be divided as follows: one-third, adjusted for capital expenditures, was used to make principal payments on the New RUS Promissory Note; one-third was used to make principal payments on the RUS ARVP Note; and the remaining value was retained by the Company.

(Dollars in thousands)

(3) Utility Plant

At December 31, 2011 and 2010, utility plant is summarized as follows:

	2011	2010
Classified plant in service:		
Production plant	$ 1,706,243	$ 1,689,024
Transmission plant	238,738	237,689
General plant	33,744	18,937
Other	543	543
	1,979,268	1,946,193
Less accumulated depreciation	936,355	909,501
	1,042,913	1,036,692
Construction in progress	49,150	54,874
Utility plant – net	$ 1,092,063	$ 1,091,566

Interest capitalized for the years ended December 31, 2011, 2010, and 2009, was $548, $684, and $133, respectively.

The Company has not identified any material legal asset retirement obligations, as defined in FASB ASC 410, *Asset Retirement and Environmental Obligations*. In accordance with regulatory treatment, the Company records an estimated net cost of removal of its utility plant through normal depreciation. As of December 31, 2011 and 2010, the Company had approximately $41,449 and $38,000, respectively, related to nonlegal removal costs included in accumulated depreciation.

(Dollars in thousands)

(4) Debt and Other Long-Term Obligations

A detail of long-term debt at December 31, 2011 and 2010 is as follows:

	2011	2010
RUS Series A Promissory Note, stated amount of $523,192, stated interest rate of 5.75%, with an imputed interest rate of 5.84% maturing July 2021	$ 521,250	$ 558,731
RUS Series B Promissory Note, stated amount of $245,530, no stated interest rate, with interest imputed at 5.80%, maturing December 2023	123,049	116,165
County of Ohio, Kentucky, promissory note, fixed interest rate of 6.00%, maturing in July 2031	83,300	83,300
County of Ohio, Kentucky, promissory note, variable interest rate (average interest rate of 3.30% and 3.27% in 2011 and 2010, respectively), maturing in June 2013	58,800	58,800
Total long-term debt	786,399	816,996
Current maturities	72,145	7,373
Total long-term debt – net of current maturities	$ 714,254	$ 809,623

The following are scheduled maturities of long-term debt at December 31:

	Amount
Year:	
2012	$ 72,145
2013	79,260
2014	21,661
2015	22,955
2016	231,882
Thereafter	358,496
Total	$ 786,399

(a) RUS Notes

On July 15, 1998, Big Rivers recorded the New RUS Promissory Note and the RUS ARVP Note at fair value using the applicable market rate of 5.82%. On the Unwind Closing Date, the New RUS Note and the ARVP Note were replaced with the RUS 2009 Promissory Note Series A and the RUS 2009 Promissory Note Series B, respectively. After an Unwind Closing Date payment of $140,181, the RUS 2009 Promissory Note Series A is recorded at an interest rate of 5.84%. The RUS 2009 Series B Note is recorded at an imputed interest rate of 5.80%. The RUS Notes are collateralized by substantially all assets of the Company and secured by the Indenture dated July 1, 2009 between the Company and U.S. Bank National Association.

(b) ***Pollution Control Bonds***

In June 2010, the County of Ohio, Kentucky, issued $83,300 of Pollution Control Refunding Revenue Bonds, Series 2010A (Series 2010A Bonds), the proceeds of which are supported by a promissory note from Big Rivers, which bears the same interest rate. These bonds bear interest at a fixed rate of 6.00% and mature in July 2031.

The County of Ohio, Kentucky, issued $58,800 of Pollution Control Variable Rate Demand Bonds, Series 1983 (Series 1983 Bonds), the proceeds of which are supported by a promissory note from Big Rivers, which bears the same interest rate as the bonds. These bonds bear interest at a variable rate and mature in June 2013.

The Series 1983 Bonds are supported by a liquidity facility issued by Credit Suisse First Boston, which was assigned to Dexia Credit in 2006. In addition, the Series 1983 Bonds are supported by a municipal bond insurance and surety policy issued by Ambac Assurance Corporation. Big Rivers has agreed to reimburse Ambac Assurance Corporation for any payments under the municipal bond insurance policy or the surety policy. Both Series are secured by the Indenture dated July 1, 2009 between the company and U.S. Bank National Association.

The Series 1983 Bonds are subject to a maximum interest rate of 13.00%. The December 31, 2011 interest rate on the Series 1983 Pollution Control Bonds was 3.25%.

(c) ***Notes Payable***

Notes payable represent the Company's borrowing on its line of credit with the National Rural Utilities Cooperative Finance Corporation (CFC) and CoBank, ACB (CoBank). The maximum borrowing capacity on the lines of credit is $100,000 consisting of $50,000 each for CFC and CoBank. In March 2011, Big Rivers paid down the $10,000 of borrowings outstanding on the CoBank line of credit at December 31, 2010. The Company had no borrowings outstanding on the lines of credit at December 31, 2011. Letters of credit issued under an associated Letter of Credit Facility with CFC reduced the borrowing capacity on the CFC line of credit by $5,375 and $5,928 at December 31, 2011 and 2010, respectively. Advances on the CFC line of credit bear interest at a variable rate and outstanding balances are payable in full by the maturity date of July 16, 2014. The CFC variable rate is equal to the CFC Line of Credit Rate, which is defined as "the rate published by CFC from time to time, by electronic or other means, for similarly classified lines of credit, but if not published, then the rate determined for such lines of credit by CFC from time to time." Advances on the CoBank line of credit bear interest at a variable rate and outstanding balances are payable in full by the maturity date of July 16, 2012. The CoBank variable rate is a fixed rate per annum (for interest periods of 1, 2, 3, and 6 months) equal to LIBOR plus the Applicable Margin as determined by the Company's credit rating. On February 25, 2011, a $2,500 CFC line of credit, available to the Company to finance storm emergency repairs and expenses related to electric utility operations, matured.

(d) ***Covenants***

Big Rivers is in compliance with all debt covenants associated with both long-term and short-term debt. The Company's Indenture and its line of credit with CFC require that a Margins for Interest Ratio (MFIR) of at least 1.10 be maintained for each fiscal year. The CoBank line of credit agreement requires that at the end of each fiscal year the Company have a Debt Service Coverage Ratio (DSCR) of not less than 1.20. Big Rivers' lines of credit with CFC and CoBank require Equity to Asset ratios of 12% and 15%, respectively. Big Rivers' 2011 MFIR was 1.12, its DSCR was 1.47 and the Asset to Equity Ratio was 27%.

(5) Rate Matters

The rates charged to Big Rivers' members consist of a demand charge per kilowatt (kW) and an energy charge per kilowatt hour (kWh) consumed as approved by the KPSC. The rates include specific demand and energy charges for its members' two classes of customers, the large industrial customers and the rural customers under its jurisdiction. For the large industrial customers, the demand charge is generally based on each customer's maximum demand during the current month. Effective September 1, 2011, the Company received approval from the KPSC to base the member rural demand charge on its Maximum Adjusted Net Local Load (as defined in Big Rivers tariff).

Prior to the Unwind Transaction the demand and energy charges were not subject to adjustments for increases or decreases in fuel or environmental costs. In conjunction with the Unwind Transaction, the KPSC approved the implementation of certain tariff riders; including a fuel adjustment clause and an environmental surcharge, offset by an unwind surcredit (a refund to tariff members of certain charges collected from the Aluminum Smelters in accordance with the contract terms). The net effect of these tariffs is recognized as revenue on a monthly basis with a partial offset to the regulatory liability – member rate mitigation described below.

The net impact of the tariff riders to members rates is currently mitigated by a Member Rate Stability Mechanism (MRSM) that was funded by certain cash amounts received from the E.ON Entities in connection with the Unwind Transaction (the Economic and Rural Economic Reserves) and held by Big Rivers as restricted investments. An offsetting regulatory liability – member rate mitigation was established with the funding of these accounts.

In its order approving the Unwind Transaction, the KPSC stipulated that Big Rivers file a rate case within three years of the Unwind Closing Date or by July 2012. On March 1, 2011, the Company filed an application with the KPSC requesting, among other things, authority to adjust its rates for wholesale electric service. The KPSC entered an order on November 17, 2011, granting Big Rivers an annual revenue increase of $26,745. One of the intervenors in the case has filed an appeal seeking, among other things, an approximate $6,200 reduction in the revenue relief granted in the order, and will presumably ask that any relief obtained be retroactive to the effective date of the rates approved in the order (September 1, 2011). Big Rivers has also sought rehearing on certain matters raised in the order that could increase Big Rivers' annual revenue by $2,735.

The wholesale rates established for the members nonsmelter large direct-served industrial customers (the Large Industrial Rate) provide the basis for pricing the energy consumed by the Aluminum Smelters.

(Dollars in thousands)

The primary component of the pricing used for the Aluminum Smelters is an energy charge in dollars per megawatt hour (MWh) determined by applying the Large Industrial Rate to a load with a 98% load factor, and adding an additional charge of $0.25 per MWh. The other components reflected in the pricing of the Aluminum Smelters' energy usage are certain charges and credits as provided for under the terms of the Aluminum Smelters' wholesale electric service agreements between Big Rivers and Kenergy Corp. (Kenergy Corp. is the retail provider for the Aluminum Smelters load).

(6) Income Taxes

At December 31, 2011, Big Rivers had a Nonpatron Net Operating Loss Carryforward of approximately $32,434 expiring at various times between 2011 and 2031, and an Alternative Minimum Tax Credit Carryforward of approximately $7,138, which carries forward indefinitely.

The Company has not recorded any regular income tax expense for the years ended December 31, 2011, 2010, and 2009, as the Company has utilized federal net operating losses to offset any regular taxable income during those years. Had the Company not had the benefit of a net operating loss carryforward, the Company would have recorded $3,613, $3,846, and $19,619 in current regular tax expense for the years ended December 31, 2011, 2010 and 2009, respectively.

The components of the net deferred tax assets as of December 31, 2011 and 2010 were as follows:

	2011	2010
Deferred tax assets:		
Net operating loss carryforward	$ 12,812	$ 16,730
Alternative minimum tax credit carryforwards	7,138	6,038
Member rate mitigation	10,326	10,326
Fixed asset basis difference	3,980	10,752
RUS Series B Note	19,689	14,767
Total deferred tax assets	53,945	58,613
Deferred tax liabilities:		
RUS Series B Note	—	—
Bond refunding costs	(9)	(8)
Total deferred tax liabilities	(9)	(8)
Net deferred tax asset (prevaluation allowance)	53,936	58,605
Valuation allowance	(53,936)	(58,605)
Net deferred tax asset	$ —	$ —

(Dollars in thousands)

A reconciliation of the Company's effective tax rate for 2011, 2010, and 2009 follows:

	2011	2010	2009
Federal rate	35.0%	35.0%	35.0%
State rate – net of federal benefit	4.5	4.5	4.5
Permanent differences	0.9	0.5	—
Patronage allocation to members	(40.8)	(38.8)	(35.4)
Tax benefit of operating loss carryforwards and other	0.4	(1.2)	(4.1)
Alternative minimum tax	3.5	3.0	0.2
Effective tax rate	3.5%	3.0%	0.2%

The Company files a federal income tax return, as well as certain state income tax returns. The years currently open for federal tax examination are 2007 through 2011 and 1996 through 1997, due to unused net operating loss carryforwards. The major state tax jurisdiction currently open for tax examination is Kentucky for years 2004 through 2011 and years 2001 through 2003, also due to unused net operating loss carryforwards. The Company has not recorded any unrecognized tax benefits or liabilities related to federal or state income taxes.

The Company classifies interest and penalties as an operating expense on the income statement and accrued expense in the balance sheet. No material interest or penalties have been recorded during 2011, 2010, or 2009.

(7) Power Purchased

Prior to the Unwind Transaction and in accordance with the Lease Agreement, Big Rivers supplied all of the members' requirements for power to serve their customers, other than the Aluminum Smelters. Contract limits were established in the Lease Agreement and included minimum and maximum hourly and annual power purchase amounts. Big Rivers could not reduce the contract limits by more than 12 MW in any year or by more than a total of 72 MW over the lease term. In the event Big Rivers failed to take the minimum requirement during any hour or year, Big Rivers was liable to LEM for a certain percentage of the difference between the amount of power actually taken and the applicable minimum requirement.

Although Big Rivers was required by the Lease Agreement to purchase minimum hourly and annual amounts of power from LEM, the lease did not prevent Big Rivers from paying the associated penalty in certain hours to purchase lower cost power, if available, in the open market or reselling a portion of its purchased power to a third party. The power purchases made under this agreement for the year ended December 31, 2009, was $51,592 and is included in power purchased and interchanged on the statement of operations.

(8) Pension Plans

(a) *Defined Benefit Plans*

Big Rivers has noncontributory defined benefit pension plans covering substantially all employees who meet minimum age and service requirements and who were employed by the Company prior to the plans closure dates cited below. The plans provide benefits based on the participants' years of service and the five highest consecutive years' compensation during the last ten years of employment. Big Rivers' policy is to fund such plans in accordance with the requirements of the Employee Retirement Income Security Act of 1974.

The salaried employees defined benefit plan was closed to new entrants effective January 1, 2008, and the bargaining employees defined benefit plan was closed to new hires effective November 1, 2008. The Company simultaneously established base contribution accounts in the defined contribution thrift and 401(k) savings plans, which were renamed as the retirement savings plans. The base contribution account for an eligible employee, which is one who meets the minimum age and service requirements, but for whom membership in the defined benefit plan is closed, is funded by employer contributions based on graduated percentages of the employee's pay, depending on his or her age.

The Company has adopted FASB ASC 715, *Compensation – Retirement Benefits*, including the requirement to recognize the funded status of its pension plans and other postretirement plans (see note 11 – Postretirement Benefits Other Than Pensions). FASB ASC 715 defines the funded status of a defined benefit pension plan as the fair value of its assets less its projected benefit obligation, which includes projected salary increases, and defines the funded status of any other postretirement plan as the fair value of its assets less its accumulated postretirement benefit obligation.

FASB ASC 715 also requires an employer to measure the funded status of a plan as of the date of its year-end balance sheet and requires disclosure in the notes to the financial statements certain additional information related to net periodic benefit costs for the next fiscal year. The Company's pension and other postretirement benefit plans are measured as of December 31, 2011 and 2010.

(Dollars in thousands)

The following provides an overview of the Company's noncontributory defined benefit pension plans.

A reconciliation of the Company's benefit obligations of its noncontributory defined benefit pension plans at December 31, 2011 and 2010 follows:

		2011		2010
Benefit obligation – beginning of period	$	28,804	$	25,493
Service cost – benefits earned during the period		1,279		1,289
Interest cost on projected benefit obligation		1,296		1,368
Benefits paid		(481)		(806)
Actuarial loss		845		1,460
Benefit obligation – end of period	$	31,743	$	28,804

The accumulated benefit obligation for all defined benefit pension plans was $25,482 and $21,977 at December 31, 2011 and 2010, respectively.

A reconciliation of the Company's pension plan assets at December 31, 2011 and 2010 follows:

		2011		2010
Fair value of plan assets – beginning of period	$	25,267	$	22,270
Actual return on plan assets		324		2,707
Employer contributions		2,890		1,096
Benefits paid		(481)		(806)
Fair value of plan assets – end of period	$	28,000	$	25,267

The funded status of the Company's pension plans at December 31, 2011 and 2010 follows:

		2011		2010
Benefit obligation – end of period	$	(31,743)	$	(28,804)
Fair value of plan assets – end of period		28,000		25,267
Funded status	$	(3,743)	$	(3,537)

(Dollars in thousands)

Components of net periodic pension costs for the years ended December 31, 2011, 2010, and 2009 were as follows:

	2011	2010	2009
Service cost	$ 1,279	$ 1,289	$ 1,241
Interest cost	1,296	1,368	1,466
Expected return on plan assets	(1,737)	(1,533)	(1,332)
Amortization of prior service cost	14	19	19
Amortization of actuarial loss	461	584	834
Settlement loss	—	—	1,690
Net periodic benefit cost	$ 1,313	$ 1,727	$ 3,918

A reconciliation of the pension plan amounts in accumulated other comprehensive income at December 31, 2011 and 2010 follows:

	2011	2010
Prior service cost	$ (26)	$ (40)
Unamortized actuarial loss	(11,151)	(9,354)
Accumulated other comprehensive income	$ (11,177)	$ (9,394)

In 2012, $14 of prior service cost and $696 of actuarial loss is expected to be amortized to periodic benefit cost.

The recognized adjustments to other comprehensive income (loss) at December 31, 2011 and 2010 follows:

	2011	2010
Prior service cost	$ 14	$ 19
Unamortized actuarial gain (loss)	(1,797)	297
Other comprehensive income (loss)	$ (1,783)	$ 316

At December 31, 2011 and 2010, amounts recognized in the balance sheets were as follows:

	2011	2010
Deferred credits and other	$ (3,743)	$ (3,537)

(Dollars in thousands)

Assumptions used to develop the projected benefit obligation and determine the net periodic benefit cost were as follows:

	2011	2010	2009
Discount rate – projected benefit obligation	4.26%	4.95%	5.59%
Discount rate – net periodic benefit cost	4.95	5.59	6.38
Rates of increase in compensation levels	4.00	4.00	4.00
Expected long-term rate of return on assets	7.25	7.25	7.25

The expected long-term rate of return on plan assets for determining net periodic pension cost for each fiscal year is chosen by the Company from a best estimate range determined by applying anticipated long-term returns and long-term volatility for various asset categories to the target asset allocation of the plans, as well as taking into account historical returns.

Using the asset allocation policy adopted by the Company noted in the paragraph below, we determined the expected rate of return at a 50% probability of achievement Level based on (a) forward-looking rate of return expectations for passively managed asset categories over a 20-year time horizon and (b) historical rates of return for passively managed asset categories. Applying an approximately 80%/20% weighting to the rates determined in (a) and (b), respectively, produced an expected rate of return of 7.28%, which was rounded to 7.25%.

Big Rivers utilizes a third party investment manager for the plan assets, and has communicated thereto the Company's Retirement Plan Investment Policy, including a target asset allocation mix of 50% U.S. Equities (an acceptable range of 45%-55%), 15% International Equities (an acceptable range of 10%-20%), and 35% fixed income (an acceptable range of 30%-40%). As of December 31, 2011 and 2010, the investment allocation was 56% and 58%, respectively, in U.S. Equities, 8% and 9%, respectively, in International Equities, and 36% and 33%, respectively, in fixed income. The objective of the investment program seeks to (a) maximize return on investment, (b) minimize volatility, (c) minimize company contributions, and (d) provide the employee benefit in accordance with the plans. The portfolio is well diversified and of high quality. The average quality of the fixed income investments must be "A" or better. The equity portfolio must also be of investment grade quality. The performance of the investment manager is reviewed semi-annually.

(Dollars in thousands)

At December 31, 2011 and 2010, the fair value of Big Rivers' defined benefit pension plan assets by asset category are as follows:

	Level 1	Level 2	December 31, 2011
Cash and money market	$ 2,129	$ —	$ 2,129
Equity securities:			
U.S. large-cap stocks	10,178	—	10,178
U.S. mid-cap stock mutual funds	3,365	—	3,365
U.S. small-cap stock mutual funds	1,666	—	1,666
International stock mutual funds	2,168	—	2,168
Preferred stock	493	—	493
Fixed:			
TIPS bond fund	723	—	723
U.S. government agency bonds	—	1,085	1,085
Taxable U.S. municipal bonds	—	3,258	3,258
U.S. corporate bonds	—	2,630	2,630
Global bond fund	—	305	305
	$ 20,722	$ 7,278	$ 28,000

	Level 1	Level 2	December 31, 2010
Cash and money market	$ 1,517	$ —	$ 1,517
Equity securities:			
U.S. large-cap stocks	9,731	—	9,731
U.S. mid-cap stock mutual funds	2,926	—	2,926
U.S. small-cap stock mutual funds	1,448	—	1,448
International stock mutual funds	2,194	—	2,194
Preferred stock	490	—	490
Fixed:			
TIPS bond fund	161	—	161
U.S. government agency bonds	—	1,843	1,843
Taxable U.S. municipal bonds	—	2,635	2,635
U.S. corporate bonds	—	2,322	2,322
	$ 18,467	$ 6,800	$ 25,267

(Dollars in thousands)

Expected retiree pension benefit payments projected to be required during the years following 2011 are as follows:

		Amount
Years ending December 31:		
2012	$	2,330
2013		4,386
2014		1,799
2015		3,196
2016		3,265
2017 – 2020		10,986
Total	$	25,962

In 2012, the Company expects to contribute $970 to its pension plan trusts.

(b) Defined Contribution Plans

Big Rivers has two defined contribution retirement plans covering substantially all employees who meet minimum age and service requirements. Each plan has a thrift and 401(k) savings section allowing employees to contribute up to 75% of pay on a pre-tax and/or after-tax basis, with employer matching contributions equal to 60% of the first 6% contributed by the employee on a pre-tax basis.

A base contribution retirement section was added and the plan name changed from thrift and 401(k) savings to retirement savings, effective January 1, 2008, for the salaried plan and November 1, 2008, for the bargaining plan. The base contribution account is funded by employer contributions based on graduated percentages of pay, depending on the employee's age.

The Company's expense under these plans was $4,464 and $4,389 for the years ended December 31, 2011 and 2010, respectively.

(c) Deferred Compensation Plan

Big Rivers sponsors a nonqualified deferred compensation plan for its eligible employees who are members of a select group of management or highly compensated employees. The purpose of the plan is to allow participants to receive contributions or make deferrals that they could not receive or make under the salaried employees qualified defined contribution retirement savings plan (formerly the thrift and 401(k) savings plan) as a result of nondiscrimination rules and other limitations applicable to the qualified plan under the Internal Revenue Code. The nonqualified plan also allows a participant to defer a percentage of his or her pay on a pre-tax basis.

The nonqualified deferred compensation plan is unfunded, but the Company has chosen to finance its obligations under the plan, including any employee deferrals, through a rabbi trust. The trust assets remain a part of the Company's general assets, subject to the claims of its creditors. The 2011 employer contribution was $58 and deferred compensation expense was $81. As of December 31, 2011, the trust asset was $283 and the deferred liability was $202.

(Dollars in thousands)

(9) Restricted Investments

The amortized costs and fair values of Big Rivers restricted investments held for member rate mitigation at December 31, 2011 and 2010 are as follows:

	2011		2010	
	Amortized costs	Fair values	Amortized costs	Fair values
Cash and money market	$ 12,765	$ 12,764	$ 12,812	$ 12,812
Debt securities:				
U.S. Treasuries	62,073	63,917	60,941	62,582
U.S. government agency	88,324	88,485	143,809	143,922
Total	$ 163,162	$ 165,166	$ 217,562	$ 219,316

Gross unrealized gains and losses on restricted investments at December 31, 2011 and 2010 were as follows:

	2011		2010	
	Gains	Losses	Gains	Losses
Cash and money market	$ —	$ —	$ —	$ —
Debt securities:				
U.S. Treasuries	1,843	—	1,641	—
U.S. government agency	161	—	331	217
Total	$ 2,004	$ —	$ 1,972	$ 217

Debt securities at December 31, 2011 and 2010 mature, according to their contractual terms, as follows (actual maturities may differ due to call or prepayment rights):

	2011		2010	
	Amortized costs	Fair values	Amortized costs	Fair values
In one year or less	$ 43,021	$ 43,092	$ 71,111	$ 71,193
After one year through five years	120,141	122,074	146,451	148,123
Total	$ 163,162	$ 165,166	$ 217,562	$ 219,316

(Dollars in thousands)

Gross unrealized losses on investments and the fair values of the related securities, aggregated by investment category and length of time that individual securities have been in a continuous unrealized loss position at December 31, 2011 and 2010 were as follows:

	2011		2010	
	Less than 12 months		Less than 12 months	
	Losses	Fair values	Losses	Fair values
Debt securities:				
U.S. Treasuries	$ —	$ —	$ —	$ —
U.S. government agency	—	—	217	15,783
Total	$ —	$ —	$ 217	$ 15,783

The unrealized loss positions were primarily caused by interest rate fluctuations. The number of investments in an unrealized loss position as of December 31, 2011 and 2010 was zero and one, respectively. Since the Company does not intend to sell and will more likely than not maintain each debt security until its anticipated recovery, and no significant credit risk is deemed to exist, these investments are not considered other-than-temporarily impaired.

(10) Fair Value of Other Financial Instruments

FASB ASC 820 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measures. It applies under other accounting standards that require or permit fair value measurements and does not require any new fair value measurements.

The carrying value of accounts receivable, and accounts payable approximate fair value due to their short maturity. At December 31, the Company's cash and cash equivalents included short-term investments in an institutional money market government portfolio account classified as trading securities under ASC 320, *Investments – Debt and Equity Securities,* that were recorded at fair value which were determined using quoted market prices for identical assets without regard to valuation adjustment or block discount (a Level 1 measure), as follows:

	2011	2010
Institutional money market government portfolio	$ 44,844	$ 44,774

It was not practical to estimate the fair value of patronage capital included within other deposits and investments due to these being untraded companies.

Big Rivers' long-term debt at December 31, 2011 consists of RUS notes totaling $644,299, variable rate pollution control bonds in the amount of $58,800, and fixed rate pollution control bonds in the amount of $83,300 (see note 4). The RUS debt cannot be traded in the market and, therefore, a value other than its outstanding principal amount cannot be determined. The fair value of the Company's variable rate pollution control debt is par value, as each variable rate reset effectively prices such debt to the current market. At December 31, 2011, the fair value of Big Rivers' fixed rate pollution control debt was determined based on quoted prices in active markets of identical liabilities (Level 1 measure) and totaled $86,399.

(Dollars in thousands)

(11) Postretirement Benefits Other than Pensions

Big Rivers provides certain postretirement medical benefits for retired employees and their spouses. Generally, except for generation bargaining retirees, Big Rivers pays 85% of the premium cost for all retirees age 62 to 65. The Company pays 25% of the premium cost for spouses under age 62. For salaried retirees age 55 to age 62, Big Rivers pays 25% of the premium cost. Beginning at age 65, the Company pays 25% of the premium cost if the retiree is enrolled in Medicare Part B. For each generation bargaining retiree, Big Rivers establishes a retiree medical account at retirement equal to $1,200 per year of service up to 30 years ($1,250 per year for those retiring on or after January 1, 2012). The account balance is credited with interest based on the 10-year treasury rate subject to a minimum of 4% and a maximum of 7%. The account is to be used for the sole purpose of paying the premium cost for the retiree and spouse.

The discount rates used in computing the postretirement benefit obligation and net periodic benefit cost were as follows:

	2011	2010	2009
Discount rate – projected benefit obligation	4.29%	4.96%	5.78%
Discount rate – net periodic benefit cost	4.96	5.78	6.32

The health care cost trend rate assumptions as of December 31, 2011 and 2010 were as follows:

	2011	2010
Initial trend rate	7.40%	7.60%
Ultimate trend rate	4.50	4.50
Year ultimate trend is reached	2028	2028

A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	2011	2010
One-percentage-point decrease:		
Effect on total service and interest cost components	$ (211)	$ (201)
Effect on year end benefit obligation	(1,056)	(1,131)
One-percentage-point increase:		
Effect on total service and interest cost components	254	236
Effect on year end benefit obligation	1,226	1,306

(Dollars in thousands)

A reconciliation of the Company's benefit obligations of its postretirement plan at December 31, 2011 and 2010 follows:

		2011		2010
Benefit obligation – beginning of period	$	15,864	$	13,864
Service cost – benefits earned during the period		1,253		1,313
Interest cost on projected benefit obligation		754		743
Participant contributions		160		85
Benefits paid		(611)		(313)
Actuarial loss		620		172
Benefit obligation – end of period	$	18,040	$	15,864

A reconciliation of the Company's postretirement plan assets at December 31, 2011 and 2010 follows:

		2011		2010
Fair value of plan assets – beginning of period	$	—	$	—
Employer contributions		451		228
Participant contributions		160		85
Benefits paid		(611)		(313)
Fair value of plan assets – end of period	$	—	$	—

The funded status of the Company's postretirement plan at December 31, 2011 and 2010 follows:

		2011		2010
Benefit obligation – end of period	$	(18,040)	$	(15,864)
Fair value of plan assets – end of period		—		—
Funded status	$	(18,040)	$	(15,864)

The components of net periodic postretirement benefit costs for the years ended December 31, 2011, 2010, and 2009 were as follows:

		2011		2010		2009
Service cost	$	1,253	$	1,313	$	878
Interest cost		754		743		464
Amortization of prior service cost		17		17		17
Amortization of actuarial (gain)		—		—		(17)
Amortization of transition obligation		31		31		31
Net periodic benefit cost	$	2,055	$	2,104	$	1,373

(Continued)

(Dollars in thousands)

A reconciliation of the postretirement plan amounts in accumulated other comprehensive income (loss) at December 31, 2011 and 2010 follows:

	2011	2010
Prior service cost	$ (130)	$ (147)
Unamortized actuarial gain (loss)	(385)	235
Transition obligation	(31)	(62)
Accumulated other comprehensive income (loss)	$ (546)	$ 26

In 2012, $18 of prior service cost, $0 of actuarial gain, and $31 of the transition obligation is expected to be amortized to periodic benefit cost.

The recognized adjustments to other comprehensive loss at December 31, 2011 and 2010 follows:

	2011	2010
Prior service cost	$ 17	$ 18
Unamortized actuarial loss	(620)	(172)
Transition obligation	31	30
Other comprehensive loss	$ (572)	$ (124)

At December 31, 2011 and 2010, amounts recognized in the balance sheets were as follows:

	2011	2010
Accounts payable	$ (762)	$ (600)
Deferred credits and other	(17,278)	(15,264)
Net amount recognized	$ (18,040)	$ (15,864)

Expected retiree benefit payments projected to be required during the years following 2011 are as follows:

	Amount
Year:	
2012	$ 761
2013	963
2014	1,148
2015	1,277
2016	1,383
2017 – 2021	8,754
Total	$ 14,286

In addition to the postretirement plan discussed above, in 1992 Big Rivers began a postretirement benefit plan, which vests a portion of accrued sick leave benefits to salaried employees upon retirement or death. To the extent an employee's sick leave hour balance exceeds 480 hours such excess hours are paid at 20% of the employee's base hourly rate at the time of retirement or death. The accumulated obligation recorded for the postretirement sick leave benefit is $579 and $391 at December 31, 2011 and 2010, respectively. The postretirement expense recorded was $191, $21, and $45 for 2011, 2010, and 2009, respectively, and the benefits paid were $3, $5, and $78 for 2011, 2010, and 2009, respectively.

(12) Related Parties

For the years ended December 31, 2011, 2010, and 2009, Big Rivers had tariff sales to its members of $151,472, $151,001, and $125,826, respectively. In addition, for the years ended December 31, 2011, 2010, and 2009, Big Rivers had certain sales to Kenergy for the Aluminum Smelters and Domtar Paper loads of $306,420, $281,473, and $167,885, respectively.

At December 31, 2011 and 2010, Big Rivers had accounts receivable from its members of $40,314 and $36,636, respectively.

(13) Commitments and Contingencies

Big Rivers is involved in litigation arising in the normal course of business. While the results of such litigation cannot be predicted with certainty, management, based upon advice of counsel, believes that the final outcome will not have a material adverse effect on the financial statements.

Big Rivers plans to seek KPSC approval for its 2012 environmental compliance plan (ECP) in an April 2012 filing. This ECP will consist of $283,490 of capital projects, primarily for a new scrubber at the D.B. Wilson station and a new selective catalytic reduction facility at the R.D. Green station, and certain additional operations and maintenance costs. The purpose of the ECP is to allow Big Rivers to comply, in the most cost-effective manner, with the U.S. Environmental Protection Agency Cross-State Air Pollution Rule, and Mercury and Other Air Toxics Standards. Among other things, the ECP filing will seek to recover the costs of the ECP through an amendment to Big Rivers' existing environmental surcharge tariff rider, an automatic cost-recovery mechanism that is similar in function to the fuel adjustment clause. The regulatory process is expected to last six months after the filing date.

MEMBER FINANCIAL AND STATISTICAL INFORMATION

The Members operate their systems on a not-for-profit basis. Accumulated margins remaining after payment of expenses and provision for depreciation constitute patronage capital for the consumers of the Members. Refunds of accumulated patronage capital to individual consumers of the Members are made from time to time on a patronage basis subject to limitations contained in each Member's mortgage with RUS, if applicable, or other applicable debt instruments.

The Members are the owners of Big Rivers and not subsidiaries. Except with respect to the obligations of the Members under their respective wholesale power contracts and the Smelter Agreements, Big Rivers has no legal interest in, or obligation in respect of, any of the assets, liabilities, equity, revenue or margins of the Members, other than the Company's rights under these contracts. The revenues of the Members are not pledged to Big Rivers, but their revenues are the source from which they pay for power and energy and transmission services purchased from Big Rivers. Revenues of the Members are, however, often pledged under their respective mortgages or other debt instruments.

Unaudited financial and statistical information relating to the Members is set forth below. The tables present a three-year summary of the balance sheets, statements of operations and selected statistical information with respect to the Members. The information contained below has been taken from RUS Financial and Statistical Reports (RUS Form 7) provided to Big Rivers by the Members. This information about the Members may not be indicative of their future results. In addition, the assets, liabilities, equity, revenue and margins should not be attributed to Big Rivers.

Table 1
Big Rivers' Members
Selected Statistics
for the Years Ended December 31,

	Kenergy	Meade County	Jackson Purchase
2011:			
Average Monthly Residential Revenue ($)	4,690,294	2,289,973	2,422,512
Average Monthly kWh	62,843,652	30,394,614	34,269,208
Average Residential Revenue (cents per kWh)	7.46	7.53	7.07
Times Interest Earned Ratio	1.66	2.09	1.04
Equity/Assets	28%	31%	36%
Equity/Total Capitalization	36%	34%	40%
2010:			
Average Monthly Residential Revenue ($)	4,762,213	2,181,402	2,603,350
Average Monthly kWh	67,746,442	31,257,410	36,804,036
Average Residential Revenue (cents per kWh)	7.03	6.98	7.07
Times Interest Earned Ratio	1.95	2.05	2.51
Equity/Assets	27%	30%	37%
Equity/Total Capitalization	33%	34%	44%
2009:			
Average Monthly Residential Revenue ($)	4,195,793	1,940,410	2,273,613
Average Monthly kWh	59,329,974	27,753,017	32,331,404
Average Residential Revenue (cents per kWh)	7.07	6.99	7.03
Times Interest Earned Ratio	1.48	1.57	1.26
Equity/Assets	24%	29%	34%
Equity/Total Capitalization	30%	32%	40%

Table 2
Big Rivers' Members
Average Number of Customers Served by Each Member
for the Years Ended December 31,

	Kenergy	Meade County	Jackson Purchase
2011:			
Residential Service	45,294	26,402	26,054
Commercial and Industrial	9,838	2,070	3,135
Other	78	6	10
Total Customers Served	55,210	28,478	29,199
2010:			
Residential Service	45,201	26,213	26,053
Commercial and Industrial	9,714	2,048	3,087
Other	76	6	12
Total Customers Served	54,991	28,267	29,152
2009:			
Residential Service	45,111	25,940	26,034
Commercial and Industrial	9,652	2,050	3,063
Other	76	6	12
Total Customers Served	54,839	27,996	29,109

Table 3
Big Rivers' Members
Annual MWh Sales by Customer Class
for the Years Ended December 31,

	Kenergy	Meade County	Jackson Purchase
2011:			
Residential Service	754,124	364,735	411,231
Commercial and Industrial	8,640,927	94,657	239,420
Other	1,733	1,057	888
Total MWh Sales	9,396,784	460,449	651,539
2010:			
Residential Service	812,957	375,089	441,648
Commercial and Industrial	8,503,804	103,175	240,839
Other	1,737	1,103	993
Total MWh Sales	9,318,498	479,367	683,480
2009:			
Residential Service	711,960	333,036	387,977
Commercial and Industrial	8,009,814	95,266	232,273
Other	1,598	1,036	1,033
Total MWh Sales	8,723,372	429,338	621,283

Table 4
Big Rivers' Members
Annual Revenues by Customer Class
for the Years Ended December 31,

	Kenergy	Meade County	Jackson Purchase
2011:			
Residential Service	$56,283,522	$27,479,674	$29,070,144
Commercial and Industrial	367,451,614	7,131,351	14,825,266
Other	282,096	74,925	100,940
Total Electric Sales	$424,017,232	$34,685,950	$43,996,350
Other Operating Revenue	1,598,821	1,093,977	1,138,853
Total Operating Revenue	$425,616,053	$35,779,927	$45,135,203
2010:			
Residential Service	$57,146,551	$26,176,828	$31,240,203
Commercial and Industrial	342,046,117	7,396,588	14,054,697
Other	280,234	74,376	104,833
Total Electric Sales	$399,472,902	$33,647,792	$45,399,733
Other Operating Revenue	1,576,153	985,470	1,134,337
Total Operating Revenue	$401,049,055	$34,633,262	$46,534,070
2009:			
Residential Service	$ 50,349,518	$23,284,922	$27,283,351
Commercial and Industrial	297,780,615	6,825,406	13,504,966
Other	252,392	67,802	109,221
Total Electric Sales	$348,382,525	$30,178,130	$40,897,538
Other Operating Revenue	1,400,341	918,510	1,020,934
Total Operating Revenue	$349,782,866	$31,096,640	$41,918,472

Table 5
Big Rivers' Members
Summary of Operating Results
for the Years Ended December 31,

	Kenergy	Meade County	Jackson Purchase
2011:			
Operating Revenue and Patronage Capital	$425,616,053	$35,779,927	$45,135,203
Depreciation and Amortization	8,711,446	3,213,863	4,695,048
Other Operating Expenses	407,517,352	28,352,691	38,043,297
Electric Operating Margin	$9,387,255	$4,213,373	$2,396,858
Other Income	975,075	277,510	765,555
Gross Operating Margin	$10,362,330	$4,490,883	$3,162,413
Interest on Long-term Debt [(1)]	5,786,551	2,123,835	2,867,944
Tax Expenses	371,579	33,919	48,869
Other Deductions	336,396	21,732	132,877
Net Margins	$3,867,804	$2,311,397	$112,723
2010:			
Operating Revenue and Patronage Capital	$401,049,055	$34,633,262	$46,534,070
Depreciation and Amortization	8,213,077	3,053,341	4,566,846
Other Operating Expenses	381,319,367	27,460,839	36,116,760
Electric Operating Margin	$11,516,611	$4,119,082	$5,850,464
Other Income	1,145,051	451,499	1,228,198
Gross Operating Margin	$12,661,662	$4,570,581	$7,078,662
Interest on Long-term Debt [(1)]	6,159,133	2,192,938	2,722,675
Tax Expenses	354,389	32,794	46,300
Other Deductions	276,035	32,420	205,318
Net Margins	$5,872,105	$2,312,429	$4,104,369
2009:			
Operating Revenue and Patronage Capital	$349,782,866	$31,096,640	$41,918,472
Depreciation and Amortization	7,970,349	2,956,264	4,325,554
Other Operating Expenses	332,864,173	24,726,916	34,448,281
Electric Operating Margin	$ 8,948,344	$ 3,413,460	$ 3,144,637
Other Income	985,051	246,919	551,311
Gross Operating Margin	$ 9,933,395	$ 3,660,379	$ 3,695,948
Interest on Long-term Debt [(1)]	6,063,274	2,284,654	2,787,124
Tax Expenses	363,079	32,462	44,969
Other Deductions	567,124	52,403	153,032
Net Margins	$ 2,939,918	$ 1,290,860	$ 710,823

(1) Interest on Long-term Debt is net of Interest Charged to Construction.

Table 6
Big Rivers' Members
Condensed of Balance Sheet Information
As of December 31,

	Kenergy	Meade County	Jackson Purchase
2011:			
ASSETS:			
Total Utility Plant [1]	$254,810,808	$100,542,751	$137,532,214
Depreciation	71,916,962	28,322,224	45,094,854
Net Plant	182,893,846	72,220,527	92,437,360
Other Assets	60,622,340	17,276,021	14,946,421
Total Assets	$243,516,186	$89,496,548	$107,383,781
EQUITY AND LIABILITIES:			
Equity	68,964,799	27,486,487	39,063,257
Long-term Debt	121,105,202	53,522,420	57,641,085
Other Liabilities	53,446,185	8,487,641	10,679,439
Total Equity and Liabilities	$243,516,186	$89,496,548	$107,383,781
2010:			
ASSETS:			
Total Utility Plant [1]	$246,011,723	$96,282,654	$133,577,500
Depreciation	66,837,167	26,382,722	42,067,013
Net Plant	179,174,556	69,899,932	91,510,487
Other Assets	64,987,273	14,063,976	16,867,183
Total Assets	$244,161,829	$83,963,908	$108,377,670
EQUITY AND LIABILITIES:			
Equity	65,181,416	25,354,111	40,519,767
Long-term Debt	131,197,120	50,261,514	52,456,925
Other Liabilities	47,783,293	8,348,283	15,400,978
Total Equity and Liabilities	$244,161,829	$83,963,908	$108,377,670
2009:			
ASSETS:			
Total Utility Plant [1]	$239,783,186	$91,162,723	$126,585,904
Depreciation	62,290,462	24,560,838	39,314,177
Net Plant	177,492,724	66,601,885	87,271,727
Other Assets	60,673,832	12,737,097	19,302,499
Total Assets	$238,166,556	$79,338,982	$106,574,226
EQUITY AND LIABILITIES:			
Equity	$57,985,783	$23,169,273	$36,395,561
Long-term Debt	133,279,836	48,493,205	54,944,634
Other Liabilities	46,900,937	7,676,504	15,234,031
Total Equity and Liabilities	$238,166,556	$79,338,982	$106,574,226

(1) Including construction work in progress.

SUMMARY OF CERTAIN PROVISIONS OF THE MORTGAGE INDENTURE

The following is a summary of the provisions of the Mortgage Indenture. All references to the Mortgage Indenture are qualified by reference to such document. Capitalized terms used in this APPENDIX C but not otherwise defined in this Disclosure Statement shall have the meaning set forth in the Mortgage Indenture.

Security for Payment of the Mortgage Indenture Obligations

All obligations issued under the Mortgage Indenture are secured equally and ratably by a lien on substantially all the Company's owned tangible and some of the Company's intangible properties, including its electric generation and transmission facilities and certain of its contracts relating to the purchase, sale or transmission of electricity of more than one year in duration and relating to the ownership, operation or maintenance of electric generation, transmission or distribution facilities owned by the Company, but excluding all Excepted Property (defined below). The lien of the Mortgage Indenture also extends to revenue generated from the sale or transmission of electricity under certain of these contracts.

The Mortgage Indenture defines Excepted Property to include, among other things:

- Cash on hand or in banks or other financial institutions (excluding such cash to the extent it constitutes proceeds of the Trust Estate in which the security interest created by the Mortgage Indenture is perfected pursuant to the Uniform Commercial Code, for so long as such perfection continues, and also excluding cash deposited or required to be deposited with Trustee pursuant to the Mortgage Indenture);

- Contracts, contract rights and associated general intangibles not specifically subject to the lien of the Mortgage Indenture;

- Equity or debt securities (other than those securities specifically subject to the lien of the Mortgage Indenture), with limited exceptions;

- Allowances for emissions or similar rights granted by any governmental authority;

- Patents, patent licenses, and other patent rights, patent applications, service marks, trade names and trademarks (other than those specifically subject to the lien of the Mortgage Indenture);

- Claims, choses in action and judgments;

- Transportation equipment (including vehicles, vessels, airplanes and barges and all parts and supplies used in connection with that equipment);

- Goods or inventory acquired or produced for the purpose of resale in the ordinary course of business and other personal property consumable in the operation of the Company's business, and all hand and other portable tools, equipment and fuel;

- Office furniture, equipment and supplies and data processing, accounting and other computer equipment, software and supplies;

- The Company's leasehold interests as lessee (other than for office purposes) under leases for an original term of less than five years;

- The Company's leasehold interests as lessee for office purposes;

- Timber (separated from the land included in the Trust Estate), coal, ore, gas, oil, minerals, and other natural resources, and all electric energy, gas, steam, water, or other products generated, produced or purchased;

- Non-assignable permits, licenses, franchises, the Company's interest in leases as lessee or lessor, contracts and contractual and other rights not specifically subject to the lien of the Mortgage Indenture;

- Real, personal and mixed property located outside of the Commonwealth of Kentucky not specifically subject to the lien of the Mortgage Indenture;

- Any personal property located outside the Commonwealth of Kentucky in which a security interest cannot be perfected by filing a financing statement under the Uniform Commercial Code; and

- The Company's interest in other property in which a security interest cannot legally be perfected in the United States.

The Company's title to the Trust Estate and the lien of the Mortgage Indenture are subject to Permitted Exceptions which include, among other things, restrictions, exceptions, reservations, terms, conditions, agreements, leases, subleases, covenants, limitations, interests and other matters of record on the date of the Mortgage Indenture, or on property acquired by the Company after the date of the Mortgage Indenture as long as those matters do not materially impair the use of the property, reservations contained in U.S. patents, liens for non-delinquent taxes, and liens for delinquent taxes which are being contested in good faith, mechanics', materialmen's or contractors' liens arising in the ordinary course of business which are not delinquent or are being contested in good faith, local improvement district assessments, liens for judgments which are fully covered by insurance or as to which the Company is prosecuting an appeal and has set aside adequate reserves, leases as a lessor for a term of not more than ten years entered into after the date of the Mortgage Indenture, or, if more than ten years that do not materially impair the Company's use of the leased property in the conduct of the Company's business, easements, rights-of-way and other rights of others in the Company's property for limited purposes to the extent those rights do not in aggregate materially impair the use of the Trust Estate, liens for non-delinquent or contested rent, the undivided or other interests of other owners, liens on those undivided interests and rights of the owners in property owned jointly with the Company, the pledge of current assets in the ordinary course of business to secure current liabilities, and liens which have been bonded for the amount of obligations secured by those liens or for the payment of which a deposit had been made in the full amount of those liens or privileges of the Company's employees for salary or wages earned but not payable, any right of any municipal or governmental authority and the burdens of any law or regulations, restrictions or other deficiencies of title to easements used by the Company for pipelines, electric transmission lines or substations or similar facilities if the Company obtained sufficient right from the apparent owner for the use for which the same are used or the Company has power of eminent domain to correct the differences or the deficiencies may be remedied without undue effort or expense. The lien of the Mortgage Indenture will also be subject to the lien in favor of Trustee to recover amounts owed to it under the Mortgage Indenture.

The Mortgage Indenture contains provisions subjecting all of the Company's after-acquired property, other than Excepted Property, to the lien of the Mortgage Indenture with limited exceptions relating to purchase money and pre-existing liens (provided, in the case of real property, the Company files a Supplemental Indenture describing such property). In the case of any consolidation, merger, or conveyance or transfer of the Trust Estate substantially as an entirety, the Mortgage Indenture is not required to be a lien upon any property then owned or thereafter acquired by the successor entity other than upon:

- Betterments, extensions, improvements, additions, repairs, renewals, replacements, substitutions and alterations to or upon the Trust Estate;

- Property made the basis of withdrawal of cash from Trustee or the release of property from the lien of the Mortgage Indenture;

- Property acquired or constructed with the proceeds of (i) insurance on any part of the Trust Estate or (ii) any part of the Trust Estate released from the lien of the Mortgage Indenture or disposed of free from any such lien or taken by eminent domain;

- Property acquired to maintain and repair the property subject to the lien of the Mortgage Indenture in accordance with the requirements of the Mortgage Indenture;

- Property acquired or constructed with Trust Moneys (as defined below) paid upon the Company's request; and

- All property, leases, contracts, rights-of-way, franchises, licenses, permits or easements acquired in alteration, substitution, surrender or modification of those property rights, and all monies deposited with Trustee in connection with the disposition, alteration, or modification of those property rights.

In the event the Mortgage Indenture was not a lien on any such properties then owned or thereafter acquired by the successor entity, no additional Mortgage Indenture Obligations could be issued under the Mortgage Indenture (other than Mortgage Indenture Obligations issued in exchange or substitution for outstanding Mortgage Indenture Obligations).

Release and Substitution of Property

So long as no Event of Default exists under the Mortgage Indenture, the Company will be able to use and deal with the real and personal property (including licenses, permits, contracts and cash proceeds of the Trust Estate subject to the lien of the Mortgage Indenture, other than cash deposited or required to be deposited with the Indenture Trustee) subject to the lien of the Mortgage Indenture (including releasing, amending, terminating, abandoning or disposing of such property) to facilitate the Company's day-to-day operations. Certain of these transactions will require that the Company finds that such transactions will not adversely affect in any material respect the security afforded by the Mortgage Indenture and are:

- Desirable in the conduct of the Company's business; or

- Made in lieu and reasonable anticipation of the taking by eminent domain or purchase of such property by a governmental entity.

Certain of these transactions also would require the substitution of Bondable Additions, the deposit of cash with the Indenture Trustee or the retirement or defeasance of Mortgage Indenture Obligations, in each case of equivalent value of the fair value of the property to be released. Cash deposited with the

Indenture Trustee as a result of the authentication and delivery of Mortgage Indenture Obligations can be withdrawn against 90.91% of Bondable Additions or retired or defeased Mortgage Indenture Obligations of equivalent value. Trust Moneys (as hereinafter defined) can be withdrawn against Bondable Additions or retired or defeased Mortgage Indenture Obligations, in either case of equivalent value, and can, at the option of the Company, be used for the redemption of Mortgage Indenture Obligations prior to their maturity, for the payment of principal on Mortgage Indenture Obligations at their maturity or for the purchase of Mortgage Indenture Obligations. To the extent that any Trust Moneys consist of the proceeds of insurance upon any part of the property subject to the lien of the Mortgage Indenture, such Trust Moneys can be withdrawn to reimburse the Company for costs to repair, rebuild or replace the destroyed or damaged property.

"Trust Moneys" is defined in the Indenture as all money received by the Indenture Trustee:

- Upon the release of any part of the Trust Estate from the lien of the Mortgage Indenture, including all moneys received in respect of the principal of all purchase money obligations deposited with the Indenture Trustee in respect of its release of property;

- As compensation for, or proceeds of the sale of, any part of the Trust Estate subject to the lien of the Mortgage Indenture taken by eminent domain or purchased by, or sold pursuant to an order of, a governmental authority or otherwise disposed of;

- As proceeds of insurance upon any part of the Trust Estate subject to the lien of the Mortgage Indenture required to be paid to the Indenture Trustee pursuant to the Mortgage Indenture; or

- For application as Trust Moneys under the relevant provision of the Mortgage Indenture or whose disposition was not otherwise specifically provided for in the Mortgage Indenture.

Covenants

The Indenture requires the Company to establish and collect rates, rents, charges, fees and other compensation (collectively, the "Rates") that produce money sufficient, together with other moneys available to the Company, to enable the Company to comply with all covenants under the Mortgage Indenture. Subject to the approval or determination of any regulatory or judicial authority with jurisdiction over Rates, the Mortgage Indenture requires the Company to establish and collect Rates which are reasonably expected, together with other revenue of the Company, to yield a MFI Ratio equal to at least 1.10 for each fiscal year. Promptly upon any material change in the circumstances which were not contemplated at the time such Rates were most recently reviewed but not less frequently than once every 12 months, the Company will be required to review the Rates so established and, subject to any necessary regulatory approval and the approval of the RUS, if required, promptly establish or revise such Rates as necessary to comply with the foregoing requirements. The Company will not furnish or supply or cause to be furnished or supplied any use, output, capacity or service of the Company's business 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 Company's business. A failure by the Company to actually achieve a 1.10 MFI Ratio will not itself constitute an Indenture Event of Default under the Mortgage Indenture. A failure to establish Rates reasonably expected to achieve a 1.10 MFI Ratio, however, will be an Indenture Event of Default if such failure continues for 30 days after the Company receives notice thereof from either the Indenture Trustee or the holders of not less than 20% in principal amount of the outstanding Mortgage Indenture Obligations, unless such failure results from the Company's inability to obtain regulatory approval.

MFI Ratio, for any period, is (i) the sum of (a) Margins for Interest (as defined below) for such period, plus (b) Interest Charges (as defined below) for such period, divided by (ii) Interest Charges for such period. Margins for Interest means, for any period, the sum of each of the following for such period:

- Big Rivers' net margins which include revenues of the Company subject to refund at a later date but exclude provisions for (i) non-recurring charges to income, including the non-recoverability of assets or expenses, except to the extent the Company determines to recover such charges in Rates and (ii) refunds of revenues collected or accrued in any prior year subject to possible refund; plus

- Any amount included in net margins for accruals for federal and state income and other taxes imposed on income after deduction of interest expense; plus

- Any amount included in net margins for any losses incurred by any subsidiary or affiliate of the Company; plus

- Any amount the Company actually receives in such period as a dividend or other distribution of earnings of any subsidiary or affiliate of the Company (whether or not such earnings were for such period or any earlier period); minus

- Any amount included in net margins for any earnings or profits of any subsidiary or affiliate of the Company; and minus

- Any amount the Company actually contributes to the capital of, or actually pay 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), but only to the extent (i) such losses have not otherwise caused other contributions or payments to be included in net margins for purposes of computing Margins for Interest for a prior period and (ii) such amount has not otherwise been included in net margins.

Margins for Interest are determined in accordance with Accounting Requirements; provided, however, that such determination may not be made on a consolidated basis.

"Interest Charges" is defined in the Mortgage Indenture to mean, for any period, the total interest charges (whether capitalized or expensed) for such period (which, except as otherwise provided in this definition, shall be determined in accordance with Accounting Requirements) related to (i) Outstanding Secured Obligations or (ii) outstanding Prior Lien Obligations, in all cases including amortization of debt discount and premium on issuance, but excluding all interest charges related to Mortgage Indenture Obligations that have actually been paid by another Person that has agreed to be primarily liable for such Indenture 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 Mortgage Indenture Obligations included in the definition of Interest Charges without the economic substance of an assumption of liability on the part of such Person.

The Mortgage Indenture prohibits Big Rivers from making any distribution, payment or retirement of patronage capital to the members if, at the time thereof or after giving effect thereto:

- An Indenture Event of Default then exists;

- Aggregate margins and equities as of the end of the immediately preceding fiscal quarter would be less than 20% of the Company's total long-term debt and equities at such time; or
- The aggregate amount expended for all such distributions to the members on and after the date on which the Company's aggregate margins and equities first reached 20% of the Company's long- term debt and equities shall exceed 35% of the Company's aggregate net margins earned after such date.

Notwithstanding such restrictions, so long as no Indenture Event of Default exists, the Company may make distributions, payments or retirements of patronage capital to members if, after giving effect thereto, the Company's aggregate margins and equities as of the end of its most recent fiscal quarter would have been not less than 30% of the Company's total long-term debt and equities as of such date.

The Mortgage Indenture obligates the Company to keep all of its property subject to the lien of the Mortgage Indenture free and clear of other liens, subject to Permitted Exceptions and certain purchase money on after-acquired property not in excess of 80% (or with respect to property that is not necessary to the operations of the remaining portion of the Company's business, 100%) of the lesser of the cost or the fair value of such property and in the aggregate not in excess of 15% of the aggregate principal amount of all Mortgage Indenture Obligations.

Credit Enhancement

The Mortgage Indenture provides that Mortgage Indenture Obligations of any series may have the benefit of an insurance policy, letter of credit, surety bond, or other similar unconditional obligation to pay when due the principal and interest of the Mortgage Indenture Obligations of such series (each, a "Credit Enhancement") issued by a credit enhancer (a "Credit Enhancer").

Additional Mortgage Indenture Obligations

The principal amount of Mortgage Indenture Obligations that can be issued under the Mortgage Indenture is limited to three billion dollars ($3,000,000,000). However, the Mortgage Indenture may be amended to increase such limit without the consent of holders of Mortgage Indenture Obligations. Additional Mortgage Indenture Obligations, ranking equally and ratably with the Mortgage Indenture Obligations issued to refinance or evidence the Company's secured indebtedness outstanding at such time, may be issued from time to time:

- Against:
  - 90.91% of Bondable Additions;
  - 90.91% of Certified Progress Payments;
  - The aggregate principal amount of retired or defeased Mortgage Indenture Obligations;
  - The amount of cash deposited with the Indenture Trustee; and
- To evidence reimbursement Obligations to Credit Enhancers in connection with Credit Enhancement or guarantees of other Mortgage Indenture Obligations.

Bondable Additions are equal to (i) the bondable value of all certified Property Additions (as to which the lien of the Mortgage Indenture shall be subject only to Permitted Exceptions), less (ii) property ("Retirements") subject to the lien of the Mortgage Indenture that is retired after December 31, 2008 (the

"Cut-Off Date"). Property Additions are limited under the Mortgage Indenture to certain of the Company's property chargeable to its fixed plant accounts, subject to the lien of the Mortgage Indenture, acquired or constructed by the Company since the Cut-Off Date, and not subject to pre-existing liens securing indebtedness prior to or on a parity with the lien of the Mortgage Indenture. In addition Property Additions include tangible property the Company acquired from WKEC as part of the Unwind, including the flue gas desulphurization system and associated equipment at the Coleman Plant, regardless of when the Company acquired title to such property. For the purpose of calculating the amount of Property Additions and Retirements, (i) the bondable value of property acquired after the Cut Off Date is the lesser of its cost or fair value to the Company (determined as of the time of acquisition) and (ii) the bondable value of the tangible property acquired from WKEC in the Unwind is $98.5 million plus the cost of acquisition by WKEC of all such tangible property (other than the flue gas desulphurization system and associated equipment at the Coleman Plant) as reflected on the books of WKEC. The amount of Bondable Additions available for the issuance of additional Mortgage Indenture Obligations is the bondable value of all Property Additions (calculated as described above) after December 31, 2008 plus the bondable value of the tangible property acquired from WKEC in the Unwind on July 16, 2009, minus the bondable value of all property subject to the lien of the Mortgage Indenture that is retired or disposed after December 31, 2008. As a result, as of December 31, 2011, the Company could have issued approximately $233.5 million of additional Mortgage Indenture Obligations on the basis of Bondable Additions.

In order to finance the construction of generation and related facilities on a contract basis, the Company can issue additional Mortgage Indenture Obligations in an aggregate principal amount up to 90.91% of the progress payments ("Certified Progress Payments") made under qualified contracts for engineering, construction or procurement services which have been assigned to the Indenture Trustee ("Qualified EPC Contracts"). Such additional Mortgage Indenture Obligations are limited in principal amount to 30% of the Outstanding Secured Obligations under the Mortgage Indenture. As Property Additions are added to the Trust Estate as a consequence of Certified Progress Payments, the Company can certify such Property Additions as Bondable Additions to (i) issue additional Mortgage Indenture Obligations on the basis of Bondable Additions provided that the Company uses a portion of the proceeds of such additional Mortgage Indenture Obligations to pay a specified portion of the Mortgage Indenture Obligations issued on the basis of Certified Progress Payments or (ii) convert principal amounts outstanding under the Mortgage Indenture Obligations issued on the basis of Certified Progress Payments to principal amounts outstanding under the Mortgage Indenture Obligations issued on the basis of Bondable Additions.

Before the Company may issue additional Mortgage Indenture Obligations on the basis of Bondable Additions, retirement or defeasance of Mortgage Indenture Obligations, the deposit of cash with the Indenture Trustee or Certified Progress Payments, the Company must certify that its MFI Ratio was at least 1.10 during the immediately preceding fiscal year (or, if the certification is made within 90 days of the end of a fiscal year, the second preceding fiscal year) or during any consecutive 12-month period within the 15 month period immediately preceding the request for the issuance of additional Mortgage Indenture Obligations.

Events of Default and Remedies

The following are Indenture Events of Default:

- Failure to pay principal of or premium, if any, on any Indenture Obligation when due after any applicable grace period;

- Failure to pay any interest on any Indenture Obligation when due which continues for 5 days;

- Any other breach by the Company of any of its warranties or covenants contained in the Indenture which continues for 30 days after written notice thereof from the Indenture Trustee or the holders of not less than 25% in principal amount of the outstanding Mortgage Indenture Obligations, unless such default cannot be reasonably cured within such 30 day period in which case, so long as a cure is being diligently pursued, the Company shall have a reasonable period of time beyond such 30 day period to complete such cure;

- Failure to pay when due the principal of any other indebtedness for money borrowed, which failure has resulted in the declaration of acceleration of indebtedness in excess of $10 million, if such indebtedness is not discharged or such declaration of acceleration is not rescinded or annulled within 10 days after such acceleration;

- A judgment against the Company in excess of $10 million which remains unsatisfied or unstayed for 45 days after either entry of judgment or termination of stay, and such judgment remains unstayed or unsatisfied for a period of 10 days after notice thereof from the Indenture Trustee or the holders of not less than 25% in principal amount of the outstanding Mortgage Indenture Obligations; or

- Certain other proceedings in bankruptcy, receivership, insolvency, liquidation or reorganization.

Subject to the provisions of the Mortgage Indenture relating to the duties of the Indenture Trustee, in case an Indenture Event of Default should occur and be continuing, the Indenture Trustee is under no obligation to exercise any of its rights or powers under the Mortgage Indenture at the request or direction of any of the holders, unless such holders shall have offered to the Indenture Trustee a reasonable indemnity. Subject to provisions for the indemnification of the Indenture Trustee, the holders of a majority in aggregate principal amount of the outstanding Mortgage Indenture Obligations have the right to direct the time, method and place of conducting any proceeding for any remedy available to the Indenture Trustee or exercising any trust or power conferred on the Indenture Trustee, except that, so long as it is not in default with respect to its Credit Enhancement for any Mortgage Indenture Obligations, a Credit Enhancer for, and not the actual holders of, Mortgage Indenture Obligations subject to Credit Enhancement would be deemed to be the holder of such Mortgage Indenture Obligations for purposes of, among other things, taking action in connection with the remedies set forth in the Mortgage Indenture.

If an Indenture Event of Default should occur and be continuing, either the Indenture Trustee or the holders of at least 25% in aggregate principal amount of the outstanding Mortgage Indenture Obligations may accelerate the maturity of all Mortgage Indenture Obligations. However, after such declaration of acceleration, but before a sale of any of the property subject to the lien of the Mortgage Indenture or a judgment or decree based on such declaration of acceleration, the holders of a majority in aggregate principal amount of outstanding Mortgage Indenture Obligations may, under certain circumstances, rescind such declaration of acceleration if the Company has paid or deposited sufficient amounts with the Indenture Trustee and all Events of Default, other than the non-payment of accelerated principal, had been cured or waived as provided in the Mortgage Indenture.

No holder of any Indenture Obligation has any right to institute any proceeding with respect to the Mortgage Indenture or for any remedy thereunder, unless:

- Such holder had previously given to the Indenture Trustee written notice of a continuing Indenture Event of Default;

- The holders of not less than 25% in aggregate principal amount of the outstanding Mortgage Indenture Obligations had made written request and such holders (other than the Government) have offered reasonable indemnity to the Indenture Trustee to institute such proceeding as Indenture Trustee;

- The Indenture Trustee for 60 days after its receipt of such notice, request and indemnity had failed to institute any such proceeding; and

- The Indenture Trustee had not received during such 60 day period from the holders of a majority in aggregate principal amount of the outstanding Mortgage Indenture Obligations a direction inconsistent with such request.

However, such limitations on the holders' rights to institute proceedings would not apply to a suit instituted by a holder of an Indenture Obligation for the enforcement of payment of the principal of, and premium, if any, or interest on such Indenture Obligation on or after the respective due dates expressed in such Indenture Obligation.

The Mortgage Indenture provides that the Indenture Trustee, within 90 days after the occurrence of the Mortgage Indenture Event of Default (but at least 60 days after the occurrence of certain specified Indenture Events of Default), shall give to the holders of Mortgage Indenture Obligations notice of all uncured defaults known to it, provided that, except in the case of an Indenture Event of Default in the payment of principal of, and premium, if any, or interest on Mortgage Indenture Obligations, the Indenture Trustee would be protected in withholding such notice if it in good faith determines that the withholding of such notice is in the interest of the holders of Mortgage Indenture Obligations.

If an Indenture Event of Default should occur and be continuing, the Indenture Trustee may sell the property subject to the lien of the Mortgage Indenture, in either a judicial or nonjudicial proceeding, and the proceeds for disposition of such property, after payment of amounts owing to the Indenture Trustee, shall be applied as follows:

- *First*, to the payment of all amounts due to the Indenture Trustee;

- *Second*,

    - If all Mortgage Indenture Obligations shall have become due and payable, to the payment of outstanding Mortgage Indenture Obligations without preference or priority between interest or principal or among Mortgage Indenture Obligations, or

    - If the principal of all Mortgage Indenture Obligations shall not have become due and payable, then (A) first to interest installments in the order of their maturity and (B) second to principal or redemption price;

- *Third*, to payment of all other amounts due and unpaid on Mortgage Indenture Obligations;

- *Fourth*, to payment of amounts to maintain the value of reserve funds relating to certain tax exempt bonds; and

- *Fifth*, to the Company or whosoever may be lawfully entitled to receive any remaining amount.

The Indenture requires the Company to deliver to the Indenture Trustee, within 120 days after the end of each calendar year, a written statement as to its compliance with all its obligations under the Mortgage Indenture. In addition, the Company is required to deliver to the Indenture Trustee, promptly after any of its officers may be reasonably deemed to have knowledge of a default under the Mortgage Indenture, a written notice specifying the nature and duration of the default and the action the Company is taking and proposes to take with respect thereto.

Amendments and Supplemental Indentures

Waiver of Covenants

The Company's compliance with the covenants contained in the Mortgage Indenture relating to (i) limitation on liens, (ii) payment of taxes, (iii) maintenance of properties, (iv) insurance, (v) delivery of annual compliance certificates and notice of default under the Mortgage Indenture, (vi) establishing and reviewing certain Rates (other than establishing Rates necessary to comply with the covenants of the Mortgage Indenture), (vii) distributions to its members and (viii) investment of certain moneys, may be waived by a vote of the holders of a majority of the aggregate principal amount of the Mortgage Indenture Obligations outstanding.

Supplemental Indentures Without Consent of Holders

Without the consent of the holders of any Mortgage Indenture Obligations, the Company, when authorized by a board resolution, and the Indenture Trustee will be able, from time to time, to enter into one or more supplemental Indentures:

- To correct or amplify the description of any property at any time subject to the lien of the Mortgage Indenture;

- To confirm property subject or required to be subjected to the lien of the Mortgage Indenture or to subject additional property to the lien of the Mortgage Indenture;

- To add to the conditions, limitations and restrictions on the authorized amount, terms or purposes of the issue, authentication and delivery of Mortgage Indenture Obligations or of any series of Mortgage Indenture Obligations under the Mortgage Indenture;

- To create any new series of Mortgage Indenture Obligations;

- To modify or eliminate any of the terms of the Mortgage Indenture, provided in the event any such modification or elimination would adversely affect or diminish the rights of any holder, such supplemental Indenture shall state that any such modification or elimination shall become effective only when there are no Mortgage Indenture Obligations outstanding under any series created prior to such supplemental Indenture and provided the Indenture Trustee may decline to execute such supplemental Indenture which does not afford adequate protection to the Indenture Trustee;

- To evidence the succession of another corporation to the Company and the assumption by any such successor of the Company's covenants;

- To evidence the succession of another Indenture Trustee or the appointment of a co-Indenture Trustee or separate Indenture Trustee;

- To add to the Company's covenants or the Indenture Events of Default for the benefit of all or any series of Mortgage Indenture Obligations or to surrender any of the Company's rights or powers;

- To cure any ambiguity, to correct or supplement any provision in the Mortgage Indenture which may be inconsistent with any other provisions or to make any other provisions, with respect to matters or questions arising under the Mortgage Indenture, which shall not be inconsistent with the provisions of the Mortgage Indenture, provided such action shall not in the Company's opinion, as evidenced by an officer's certificate delivered to the Indenture Trustee, adversely affect the interests of the holders of the Mortgage Indenture Obligations in any material respect;

- To modify, eliminate or add to the provisions of the Mortgage Indenture to the extent necessary to effect the qualification of the Mortgage Indenture under any federal statute, to modify, eliminate or add to the provisions of the Indenture to the extent that any such provisions relating to requirements under the Trust Indenture Act of 1939 (the "TIA") have been modified or eliminated in the TIA after the date of the Mortgage Indenture, to add or change any provisions of the Indenture to the extent necessary to permit or facilitate the issuance of Mortgage Indenture Obligations in bearer or book-entry form;

- To permit the issuance of Mortgage Indenture Obligations in bearer or book-entry form;

- To make any change in the Mortgage Indenture that, in the reasonable judgment of the Indenture Trustee, would not materially and adversely affect the rights of holders of Mortgage Indenture Obligations. A supplemental Indenture will be presumed not to materially and adversely affect the rights of holders if (i) the Mortgage Indenture, as so supplemented and amended, secures equally and ratably the payment of principal of (and premium, if any) and interest on the Mortgage Indenture Obligations which are to remain outstanding and (ii) the Company shall furnish to the Indenture Trustee written evidence from (x) the nationally recognized statistical rating organization or organizations then rating the Mortgage Indenture Obligations (or other Obligations primarily secured by Mortgage Indenture Obligations) or (y) if there are more than two (2) such organizations, at least two (2) of such organizations, that its ratings of the Mortgage Indenture Obligations (or other Obligations primarily secured by Mortgage Indenture Obligations) will not be withdrawn or reduced as a result of the changes in the Indenture affected by such supplemental Indenture, provided that any changes in the Mortgage Indenture that require the consent of all of the holders of Mortgage Indenture Obligations affected thereby may not be made on the basis that they do not materially and adversely affect the rights of holders. See "Supplemental Indentures With Consent of Holders;" and

- To increase the maximum principal amount of Mortgage Indenture Obligations which may be authenticated and delivered under the Mortgage Indenture.

Supplemental Indentures With Consent of Holders

With the consent of the holders of not less than a majority in principal amount of the Mortgage Indenture Obligations of all series then outstanding affected by such supplemental Indenture, the Company and the Indenture Trustee will be able, from time to time, to enter into one or more supplemental Indentures to add, change or eliminate any of the provisions of the Mortgage Indenture or modify the rights of the holders of such Mortgage Indenture Obligations, but no such supplemental Indenture will, without the consent of the holder of each outstanding Indenture Obligation affected thereby:

- Change the Stated Maturity (the date specified in each Mortgage Indenture Obligations as the date on which the principal of such Mortgage Indenture Obligations or an installment of interest on any Indenture Obligation is due and payable);

- Reduce the principal of, or any installment of interest on, any Indenture Obligation, or any premium payable upon the redemption thereof;

- Change any Place of Payment (the city or political subdivision thereof in which the Company is required by the Indenture to maintain an office or agency for payment of the principal of or interest on the Mortgage Indenture Obligations) where any Indenture Obligation, or the interest thereon, is payable;

- Impair the right to institute suits for the enforcement of any such payment on or after the Stated Maturity thereof (or, in the case of redemption, on or after the redemption date);

- Reduce the percentage in principal amount of the outstanding Mortgage Indenture Obligations the consent of the holders of which is required for various purposes;

- Modify certain other provisions of the Mortgage Indenture;

- Permit the creation of any lien (other than as permitted in the Mortgage Indenture) ranking prior to or on a parity with the lien of the Mortgage Indenture with respect to all or substantially all of the property subject to the lien of the Mortgage Indenture; or

- Modify the provisions of any mandatory sinking fund so as to affect the rights of a holder to the benefits thereof.

Defeasance

Subject to certain other conditions, the Mortgage Indenture provides that Mortgage Indenture Obligations will be deemed to have been paid and any of the Company's Obligations to the holders of such Mortgage Indenture Obligations will be discharged, if the Company deposits with the Indenture Trustee or paying agent cash or Defeasance Securities (as defined below) maturing as to principal and interest in such amounts and at such times as are sufficient, without consideration of reinvestment of such interest, to pay when due the principal or (if applicable) redemption price and interest due and to become due on such Mortgage Indenture Obligations. "Defeasance Securities" is defined in the Mortgage Indenture to include non-callable bonds or other obligations of the principal and interest on which constitute direct obligations of, or are unconditionally guaranteed by the United States of America, or certificates of interest or participation in any such obligations, or in specified portions thereof (which may consist of specified portions of the interest thereon).

SUMMARY OF CERTAIN PROVISIONS OF THE SMELTER AGREEMENTS

The following is a summary of certain provisions of the Smelter Agreements. This summary does not purport to be complete or definitive and is qualified in its entirety by reference to the summarized documents. The Smelters have largely identical obligations under the agreements described below, so this summary does not distinguish between obligations to a particular Smelter, even though, from a legal perspective, their rights and obligations are separate and not joint. All capitalized terms used in this APPENDIX D summary and not defined herein or elsewhere in the Disclosure Statement shall have the meanings given to them in the Smelter Agreements.

Structure

The principal terms and conditions relating to the sale of electric services by Big Rivers to Kenergy for resale to the Smelters are set forth in six agreements, three with respect to service to each Smelter. The basic structure of the sale of electric services is that the Company sells the electric services to Kenergy and then Kenergy in turns sells those electric services to each Smelter. Because the Smelters are customers of Kenergy, Big Rivers has entered into two, separate wholesale service agreements (each a "Smelter Agreement") with Kenergy. Under each Smelter Agreement, the Company supplies Kenergy with electric service for resale to a particular Smelter. Kenergy has entered into a separate retail electric service agreement (a "Smelter Retail Agreement") with each Smelter. The Company and each Smelter have also entered into a Smelter Coordination Agreement (a "Smelter Coordination Agreement" and, together with the Smelter Agreements and the Smelter Retail Agreements, the "Smelter Agreements") that sets forth certain direct obligations between the Company and a Smelter. Due to the pass-through nature of the principal obligations between the Company and each Smelter, the Smelter Agreement and the Smelter Retail Agreement relating to each Smelter are substantially the same.

Nature of Service

The aggregate amount of energy made available to the Smelters under the Smelter Retail Agreements consists of three types of energy referred to as (1) Base Monthly Energy, (2) Supplemental Energy and (3) Back-Up Energy.

Base Monthly Energy

The primary type of energy provided is Base Monthly Energy. "Base Monthly Energy" is the actual amount of energy delivered to the Smelter other than Supplemental Energy provided by Big Rivers or Market Energy provided by third-party suppliers plus energy not delivered as a result of the Smelter's exercise of certain rights to curtail deliveries of energy. Base Monthly Energy is capped at 368 MW per hour for Alcan and 482 MW per hour for Century. The Smelter Retail Agreements do not require the Smelters to schedule Base Monthly Energy but do require each Smelter to use reasonable commercial efforts to inform Kenergy and the Company promptly of any material change in its intended usage of Base Monthly Energy.

Supplemental Energy

In addition to Base Monthly Energy, the Smelters may purchase Supplemental Energy in certain circumstances. "Supplemental Energy" itself consists of three distinct subsets of energy products in excess of Base Monthly Energy:

Interruptible Energy. Each of the Smelters may purchase up to 10 MW per hour in excess of Base Monthly Energy, from the Company's power supply resources on an interruptible basis ("Interruptible Energy"). Interruptible Energy may be interrupted if the Company determines in good faith that its energy resources will be insufficient to supply both the requested Interruptible Energy and its obligations to the Members, all other obligations to the Smelters, and any firm commitments to third parties made prior to the Company's agreement to sell such Interruptive Energy.

Buy-Through Energy. If the Company interrupts any Interruptible Energy, then the Company may, at its option, offer energy at a quoted price following the notice of interruption ("Buy-Through Energy"). In practice, the Company purchases this energy from a third-party supplier in the market and then re-sells it to Kenergy for resale to the Smelter. If the Smelter agrees to purchase Buy-Through Energy, the Company will have a firm obligation to supply Buy-Through Energy, subject to limited exceptions.

Market Energy. Apart from all other energy, at the request of a Smelter, Kenergy will use reasonable commercial efforts to purchase separately negotiated additional energy and related services ("Market Energy") from either the Company or third-party suppliers. The Company has no obligation to provide Market Energy to Kenergy for resale to the Smelters but may elect to do so.

Back-Up Energy

Because the Smelter's receive in each hour energy that meets their actual demand in the hour, the Smelters also purchase and pay for "Back-Up Energy." Back-Up Energy is, for any hour, energy in excess of Base Monthly Energy and Supplemental Energy. Back-Up Energy is intended to be imbalance energy, that is, energy actually used in excess of the Smelter's planned usage in any hour. The Smelters are not required to schedule Back-Up Energy, but the Smelters must use reasonable commercial efforts to inform Kenergy and Big Rivers promptly of any material change in their intended usage of Back-Up Energy.

Smelter Payment Obligations

Base Monthly Energy Charge

The calculation of the charges for Base Monthly Energy contains numerous components. In sum, the charges are intended to result in the Smelters making payments that help the Company achieve a net margin so that the Company's net margin plus interest expenses divided by interest expenses is 1.24. This ratio is referred to herein as a "TIER". The charges to reach a TIER of 1.24 are subject to specified limits on the maximum amount payable by the Smelters and certain other adjustments.

Base Energy Charge. The "Base Energy Charge" is the charge for Base Monthly Energy made available to the Smelters. The Base Energy Charge is equal to the Smelter's Base Demand (368 MW or 482 MW, respectively) per hour, assuming a 98% load factor, multiplied by the Company's tariff rate for sales to its Members for resale to large direct-served industrial customers (the "Large Industrial Rate") (inclusive of any surcharges, surcredits and rebates, exclusive of certain fuel adjustment charges and environmental surcharges, the Rebate and the Surcharge (each as defined below)), plus an additional amount of $0.25 per MWh. In addition, the Base Energy Charge includes an adjustment, either positive or negative, for specified variable costs, based on the Smelters' actual energy curtailments.

Supplemental Energy Charges. The charges for Supplemental Energy are the sum of charges for the Interruptible Energy Charge, the Buy-Through Energy Charge, and the Market Energy Charge, calculated as follows:

1. The "Interruptible Energy Charge" is the product of (a) the quantity of Interruptible Energy metered at the point of delivery during the billing month, and (b) the rate or rates for Interruptible Energy proposed by the Company and accepted by the Smelter with respect to such billing month;

2. The "Buy-Through Energy Charge" is a "pass-through" amount for the Company's costs to purchase such Buy-Through Energy from a third-party supplier for sale to Kenergy for resale to the applicable Smelter, including any amount paid for transmission and ancillary services and all other charges payable by the Company in connection with Buy-Through Energy; and

3. The "Market Energy Charge" equals the product of the rate agreed to by the supplier of the energy, which may be but is not necessarily the Company, and the amount of the Market Energy and any amount paid for transmission and ancillary services.

Back-Up Energy Charges. The rates for Back-Up Energy depend on whether the Company has to purchase that energy in the market. If so, the rate is 110% of the highest price for energy purchased by and delivered to the Company during that hour. If the Back-Up Energy was not purchased in the market, then the rate is the greater of the locational marginal price at the Company's interface with Midwest Independent System Operator or the Company's system lambda. If Back-Up Energy exceeds 10 MW in any hour, the rate for the excess over 10 MW is computed differently. If this excess Back-Up Energy is required due to a third-party breaching a contract to supply Market Energy (and thereby reducing the energy supplied to a Smelter), then the rate is 110% of the highest price for energy purchased by or sold by the Company in that hour. If there is no such contractual breach, then the rate for Back-Up Energy in excess of 10 MW is the higher of $250 per MWh or 110% of the highest hourly rate for energy purchased or sold by Big Rivers and delivered to an interconnection with the Company's transmission system in such hour.

TIER Adjustment Charge

Prior to each fiscal year, the Company determines the expected total amount of additional revenue it will need during the fiscal year to achieve a TIER of 1.24, subject to certain limitations (the "TIER Adjustment"). Each Smelter is obligated to pay a pro rata share (calculated based on its Base Demand) of the TIER Adjustment. If one Smelter's Retail Agreement terminates early, the other Smelter will continue to be obligated to pay only its pro rata share of the TIER Adjustment calculated based on the terminated Smelter's Base Demand, which is 368 MW for Alcan and 482 MW for Century. Each month, one-twelfth of each Smelter's share of the estimated TIER Adjustment for such fiscal year is charged to the Smelter as a "TIER Adjustment Charge". These monthly amounts are further subject to quarterly adjustments based on year-to-date results of operations.

The Smelters' obligations to pay amounts toward the Company achieving a TIER of 1.24 are not unlimited. Each Smelter's obligation with respect to the TIER Adjustment in any fiscal year may not exceed an amount equal to the product of (a) the Smelters' Based Fixed Energy, for such fiscal year, and (b) the applicable amount set forth below for such year:

Years	Applicable Amount
2009-2011	$0.00195 per kWh
2012-2014	$0.00295 per kWh
2015-2017	$0.00355 per kWh
2018-2020	$0.00415 per kWh
2021-2023	$0.00475 per kWh

Assumptions in the TIER Adjustment. Big Rivers and Kenergy have agreed with the Smelters to make certain assumptions and adjustments in the calculation of the TIER Adjustment. These assumptions and adjustments are intended to limit the Smelters' obligations in some specified circumstances. Specifically, for purposes of calculating the TIER Adjustment, it will be assumed that:

1. The Company raises its base rates for service to its Members for their non-Smelter customers by a weighted average of 2.00% in 2010, 2.50% in 2018 and 4.00% in 2021 to the extent the Company in fact previously had not increased revenues as a result of rate increases by at least such amount.

2. Any entity which becomes a direct-serve customer of a Member after the closing of the Unwind with firm demand in excess of 15 MW paid at least an amount equal to the Smelter Base Rate adjusted for the entity's actual load factor, plus a proportionate share of the TIER Adjustment, if any, and additional amounts relating to the Fuel Adjustment Clause, the Environmental Surcharge, the Purchased Power Adjustment, and the Surcharge. An entity which becomes a direct-serve customer of a Member with a demand of 15 MW or less paid at least an amount equal to the Large Industrial Rate, plus additional amounts relating to the Fuel Adjustment Clause, the Environmental Surcharge, and the Purchased Power Adjustment. This assumption will not be made in the last three years of the term of either Smelter Retail Agreement or following notice of termination of either Smelter Retail Agreement.

3. The Company's will have incurred no expenses that are impermissible for inclusion in rates of electric generation and transmission cooperative utilities subject to the jurisdiction of the KPSC or disallowed by another governmental authority, provided however that a denial by the KPSC or another governmental authority of expense recovery through the Fuel Adjustment Clause or the Environmental Surcharge shall not make such expense impermissible for the purpose of this assumption if the nature of the expense is recoverable in base rates.

4. There are no revenues and expenses associated with the Company's non-regulated businesses.

5. Additional costs related to a change in the Company's depreciation rates may not be included in calculation of the Tier Adjustment unless such changes have been approved, consented to, or accepted by the KPSC, or any other governmental authority if the KPSC no longer has jurisdiction over the change.

In general, these assumptions attempt to ensure that the TIER Adjustment payable by the Smelters is not changed in ways outside the expectations of the parties as a result of known anticipated events.

Other assumptions attempt to net out certain effects of, among other things, (a) patronage capital retirements, (b) interest imputed on debt related to new non-peaking facilities to the extent such new facilities are not included in the Company's revenue requirements for rate-making purposes, (c) interest related to construction-work-in-progress to the extent not included in the Company's revenue requirements for rate-making purposes, (d) possible future indemnification payments under a Smelter Agreement, (e) agreed curtailments, (f) certain penalties, including possible criminal penalties imposed by governmental authorities, (g) penalty interest due to Kenergy or the Company because of a default by a Smelter, (h) interest on payments made under protest by the Smelters, (i) certain excess reactive demand charges, (j) certain administrative fees paid in connection with certain energy curtailment and resale under a Smelter Agreement.

Rebate. If the Company's TIER in any year exceeds 1.24, as calculated under the Smelter Agreements, then during the next fiscal year the Company may elect to rebate on a kWh basis a portion of the excess amount, subject to certain limitations, to the Members. Big Rivers has a rider to its tariff to effect this transfer to the Members. Kenergy then would credit to the Smelters a pro rata portion of the amount it received from the Company on a kWh basis (the "Rebate"). If the Company does not elect to rebate such excess amount to all its Members, the Company will still distribute a pro rata portion of the excess to Kenergy for distribution to the Smelters (the "Equity Development Credit"), subject to certain limitations.

Additional Charges

Variable Charges. The Smelters pay charges under the Company's Fuel Adjustment Clause, and an environmental surcharge (the "Environmental Surcharge") as though they were large industrial tariff customers of one of the Members. The Smelters also pay a charge relating to a purchased power adjustment (the "Purchased Power Adjustment") with respect to purchased power costs not recovered under the Fuel Adjustment Clause.

Surcharge. In addition to any other amounts payable under the Smelter Agreements, the Smelters pay a Surcharge, comprised of four separate components. The first component of the Surcharge is a fixed annual payment, in such amount as follows: (1) an aggregate annual payment of $5,110,000, payable in equal monthly installments through 2011, (2) an aggregate annual payment of $7,300,000, payable in equal monthly installments from 2012 through and including 2016, and (3) an aggregate annual payment of $10,182,816, payable in equal monthly installments from 2017 through 2023. The second component is a fixed reduction to the Surcharge of $86,588 per month for Alcan and $113,412 per month for Century until July 2017. The third and fourth components of the Surcharge are not fixed dollar amounts. The third component is the product of Base Fixed Energy for the billing month (where "Base Fixed Energy" equals the product of the Base Demand (368 MW or 482 MW, respectively), the number of hours in the billing month, and 0.98) multiplied by $0.60 per MWh. The fourth component is the product of Base Fixed Energy for the billing month and the number of cents (between zero and 60) per MW per hour that the Company's budgeted annual average fuel costs for coal-fired generation per MWh for the fiscal year exceed the amounts specified in the Smelter Retail Agreements for that fiscal year, subject to a quarterly true-up based on a comparison of actual fuel costs to budgeted fuel costs and an annual true-up to insure that the Smelters do not pay under this fourth component more than 60 cents per MW per hour of Base Fixed Energy for the fiscal year.

Termination Rights

The obligation of Kenergy to supply electric services to the Smelters pursuant to the Smelter Retail Agreements will terminate on December 31, 2023, unless terminated earlier pursuant to the terms thereof. If no such early termination occurs, Big Rivers, and Kenergy are obligated, by no later than January 1, 2023, to undertake good faith negotiations with each other and the applicable Smelter for a replacement agreement.

A Smelter may terminate its Smelter Retail Agreement upon not less than one year's prior written notice of such termination to Kenergy and Big Rivers if it's corporate parent has made a business judgment in good faith to terminate and cease, and has no current intention to re-commence, aluminum smelting operations at the Smelter's Sebree, Kentucky site, in the case of Alcan, or Hawesville, Kentucky site, in the case of Century.

Curtailments

There are five specified circumstances under which the Smelters may curtail their receipt of energy from the Company. In each case, the Smelters remain obligated to pay for the amount of curtailed energy as though it had been delivered, and receive a credit with respect to the curtailed energy which differs depending on the circumstances of the curtailment.

Surplus Sales. The Company is required to use reasonable commercial efforts to market amounts of Monthly Energy for Kenergy that a Smelter is obligated to purchase under its Smelter Retail Agreement but which is surplus to such Smelter's needs, with some exceptions. The Company must credit back to Kenergy, for credit to the applicable Smelter, an amount of net proceeds from such sales which is generally equivalent to the amount of the Smelters' charges otherwise payable with respect thereto, less an administrative fee of $0.25 per MWh.

Undeliverable Energy Sales. If an event occurs that causes damage or destruction to the plant or equipment at a Smelter's facility that limits that Smelter's ability to engage in smelting operations for a period of 48 consecutive hours or longer and the Smelter's demand drops by at least 50 MW (other than as a result of the Smelter's willful or intentional misconduct), the Smelter can request such energy be resold for five or six months ("Undeliverable Energy Sales"). If the Smelter certifies that such condition cannot be remedied with reasonable diligence within six months, such sales may be extended for an additional three months. Big Rivers must credit back Kenergy, for credit to the Smelter, the net proceeds of the Undeliverable Energy Sales, less an administrative fee of $0.25 per MWh.

Potline Reduction Sales. A Smelter, upon the ceasing of aluminum smelting operations on one of its potlines (a "Potline Reduction"), may request that Kenergy cause the Company to sell 115 MW (plus or minus 10 MW) per hour on the open market ("Potline Reduction Sales") if certain other conditions are met These conditions include among others: (a) such Smelter is reasonably likely to be able to continue aluminum smelting operations with respect to all of its other potlines; (b) such Smelter reasonably estimates the Potline Reduction will equal or exceed 12 months; and (c) no Potline Reduction Sales have been made for a period of twelve consecutive months prior to the date of such notice. The Company must credit back Kenergy, for credit to the Smelter, the net proceeds of Potline Reduction Sales, less an administrative fee of $0.25 per MWh.

Economic Sales. Each Smelter may, not more than 12 times in any fiscal year, voluntarily curtail its energy requirements and request that the Company sell the curtailed energy ("Economic Sales"). Each Economic Sale is subject to the Company's consent, limited to up to 100 MW, and may not be longer than four hours. The Company must credit back to Kenergy, for credit to the Smelter, 75% of the net proceeds of Economic Sales.

Neither the Company nor Kenergy have any obligation to market energy as Surplus Sales, Undeliverable Energy Sales, Potline Reduction Sales or Economic Sales until the Company has sold or chosen not to sell all amounts of its own surplus power, nor do Kenergy or the Company have any obligation to the Smelters if the Company is unable to sell this energy as a result of transmission or other constraints.

Other Curtailments. If mutually agreed by a Smelter, Kenergy and Big Rivers, a Smelter may curtail its energy requirements in an amount and for a period agreed upon by such Smelter, Kenergy and Big Rivers. Regardless of whether the Company sells any of such curtailed energy, it must credit back to Kenergy, for credit to the Smelter, an amount equal to the product of (a) the amount of Base Demand per Hour curtailed and (b) the "Market Reference Rate." The Market Reference Rate is the rate (inclusive of all transmission and related charges on any third-party's transmission system) the Company estimates in good faith it would have paid to purchase energy from a third-party for such amount of curtailed energy to meet its energy delivery obligations under the Smelter Agreements during such period. This curtailment option allows the Company, if consented to by a Smelter in each instance, to mitigate its exposure to short-terms price spikes in the wholesale power markets during periods when the Company would otherwise need to purchase power from the market to meet its energy delivery obligations under the Smelter Agreements.

Other Matters

Covenants. Big Rivers is obligated to its Members to operate its system for the benefit of the Members consistent with prudent utility practices. Under the Smelter Agreements it will apply the same standards to operating decisions that may affect the monthly charges to the Smelters. The Company will not use a Smelter's payment obligation with respect to the Tier Adjustment as the basis for making an operating decision.

Restructuring. Because of the Smelters' obligations relating to the TIER Adjustment, the Company has agreed that the effects of certain restructuring transactions (a "Restructuring") on the TIER Adjustment will be implemented over an extended period of time. A restructuring will occur if (i) Big Rivers, any Affiliate or a Member engages in a merger, consolidation or other combination with another entity, or the Company admits a new member, and such transaction results in a 5% increase in sales to its Members on a pro forma basis or (ii) the Company is acquired. The Company may, however, seek approval of an increase in the Large Industrial Rate which will increase amounts otherwise payable by the Smelters pursuant to the Smelter Base Rate upon the occurrence of a Restructuring. In connection with such a Restructuring, Big Rivers, Kenergy and the Smelters will determine a good faith estimate of the cumulative increase or decrease in the TIER Adjustment that such a Restructuring would cause over the 24 Billing Month period following the date of the effectiveness of the Restructuring (the "Restructuring Amount") and would increase or decrease the Smelters' charges for 48 months by 1/48th of the Restructuring Amount (subject to a lower limit on the overall MWh rate payable by the Smelters). If the Company, Kenergy and the Smelters are not able to determine a mutually agreeable estimate of the appropriate economic adjustment according to the procedures set forth in the Smelter Retail Agreements, then Kenergy, Alcan, Century, or the Company may petition to the KPSC to determine the Restructuring Amount.

Budgets. Each year, the Company must provide the Smelters with a copy of its then-current projected operating and capital budgets for the following fiscal year. This estimated budget may be reviewed by a mutually agreed independent expert if requested by a Smelter who will evaluate the proposed budgeted operating expense and capital expenditures. The Smelters have the opportunity to present the conclusions and recommendations of the independent expert to the Coordinating Committee (defined below) and to the Board of Directors. The Company has no duty to take any action based on such report. The Company must also provide the Smelters with notice of certain significant capital expenditures or operating expenses in excess of its budget made during the fiscal year and allow the Smelters to make a presentation to its Board of Directors in some cases.

Coordinating Committee. The Smelter Agreements provide for the establishment of a committee (the "Coordinating Committee"), consisting of representatives of the Members, Alcan, Century, and the Company's management, organized for the purpose of analyzing information relating to the Company's operational and financial performance, including among others, (i) analysis criteria and procedures for evaluating plans and expenditures, (ii) budgets, (iii) fuel procurement or supply, and (iv) actual budget performance and variances.

Large Industrial Rate Service. The Company has agreed that if a Smelter's Retail Agreement is terminated pursuant to the termination rights with respect to a cessation of all smelting operations at the Smelter's site, the Smelter will be entitled to be served by Kenergy under the Company's Large Industrial Rate for any non-smelting load up to a maximum load of 15 MW.

Smelter Credit Support

The U.S. parent of Alcan and the ultimate parent of Century have entered into agreements guaranteeing the payment and performance of Alcan and Century, respectively, to Kenergy and to the Company of all obligations under the Smelter Coordination Agreements.

Because the parent guarantor of each Smelter does not have an "A+" or higher credit rating, each Smelter is required to provide and maintain credit support in the form of a letter of credit from a bank rated "A+" or higher, or other credit support acceptable to the Company and Kenergy, in an amount equal to the amounts estimated to be due for a period of two months under that Smelter's Smelter Retail Agreement and any amount that the Company estimates reasonably could be due with respect to taxes relating to certain sales of energy on behalf of the Smelters.

Both Smelters have negotiated other credit support acceptable to the Company and Kenergy. For their 2 month credit support, Century currently has in place a $30 million letter of credit from Wells Fargo and Alcan currently has in place a $21 million letter of credit from TD Bank and a Threshold Amount of $2 million pursuant to the PNC escrow agreement. Century has been requested to increase their credit support by $4 million, to $34 million by July 2, 2012, and Alcan recently increased theirs by $3 million, to $26 million.

Patronage Capital

The Company's and Kenergy's allocation and distribution of patronage capital is controlled by their respective by-laws. The Smelter Agreements restrict Kenergy and the Company from modifying their respective by-laws in a manner that would be adverse to the Smelters with respect to the distribution of patronage capital. The decision to make any payments with respect to the distribution of patronage capital is in the sole discretion of Kenergy or the Company, as applicable.

First Updated Response to KIUC 2-3 [*End*]

Big Rivers Electric Corporation Disclosure Statement, July 12, 2012