ORIGINAL

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

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PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES	)))	Case No. 2013-00199

Response to the Kentucky Industrial Utility Customers'
Second Request for Information
dated September 16, 2013

FILED: September 30, 2013

ORIGINAL

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2013-00199

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Item 1) *Based on the Company's production cost projection, for each year between 2014 and 2027, provide hourly results for the following:*

a. *Hourly load by each load category Big Rivers' models in its production cost model (BREC load, HMPL load, etc.)*

b. *Hourly unit generation by each unit that serves load (hydro, HMPL gen, BREC gen, etc.)*

c. *Hourly purchases by each purchase type*

d. *Hourly sales by each sale type*

e. *Hourly unit operating costs by each unit that serves load, hourly purchase costs for each purchase type, and hourly sales cost for each sale type*

f. *Hourly market price for each market price forecast modeled and as entered in the production cost model. Also, indicate which loads are priced against which market price forecast, and which generating units are priced against which market price forecast.*

g. *Please state whether based on the hourly results provided from above, and the hourly market price results provided from above, enough information is available to calculate the same monthly production costs that are supplied in the PCM file. If not please supply a list of items that are needed in addition*

to what has been requested above, and supply the additional hourly values that are necessary. Please supply this information electronically with all formulas intact.

Response)

a. Please see the attached CONFIDENTIAL electronic file entitled "KIUC 2-1(a) Att. Elec. CONFIDENTIAL - PCM Run(May-13 to Dec-28) Hourly Load Data.xlsx" displaying the hourly data. The same load data was utilized for all of the seven PCM runs performed for this rate case (Case No. 2013-00199).

b. Please see the attached CONFIDENTIAL electronic file entitled "KIUC 2-1(b) Att. Elec. CONFIDENTIAL -PCM Run(May-13 to Dec-28) Hourly Data.xlsx" displaying the hourly data for each of the seven PCM runs performed for this rate case (Case No. 2013-00199).

c. Please see Big Rivers' responses to subparts (a) and (b) above. Please understand that Big Rivers purchases its entire load from MISO at the BREC.BREC LMP price (in the hourly data file the entity is DI_BREC BREC_ATC).

d. Please see Big Rivers' responses to subparts (a) and (b) above. Please understand that Big Rivers sells all of its generation to MISO at the respective generator LMP price. In the hourly data file provided in Big Rivers' response to subpart (b) above, the three Coleman units utilize DI_COLEMAN_ATC, the other generating units utilize DI_BREC GEN_ATC and SEPA (hydro) utilizes the load LMP (DI_BREC BREC_ATC) for their respective LMP pricing.

e. The total hourly unit operating costs are not available as the PCM model utilizes the generation input data (heat rate, fuel cost, VOM cost, emission rates, start costs, unit operating parameters, etc.) and economically dispatches each unit. All the previously listed data would need to be downloaded hourly, and mathematic calculations would need to be performed on the downloaded data, to determine the total hourly unit operating cost. On the PCM Run exhibits provided, the monthly operations cost can be found on the "Monthly Resource Report" tab. The hourly purchase costs and hourly sales revenue can be calculated by multiplying the amount (MW) by the respective price LMP ($/MW).

f. Please see Big Rivers' responses to subparts (c) and (d) above.

g. Please see Big Rivers' response to subpart (e) above as the total hourly unit operating cost would be needed which is not available. The generation inputs file was provided in Big Rivers' response KIUC 1-12(b,d-f). Please recall that the PCM is only dealing with the variable costs and does not include any fixed costs.

Witness) Robert W. Berry

Electronic Attachment(s) Produced Separately

BIG RIVERS ELECTRIC CORPORATION

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Item 2) ***In the PCM file - Big Rivers PCM Run 4-22-13 (2013-2027).xlsx, tab Monthly Net Market Positions, there are columns - Sum of Net Purchases, and Sum of Net Sales. Please provide a narrative explanation of how these values are derived, and state what individual purchases and sales sum together to make up Net Purchases and Net Sales. Please provide those individual monthly purchases and sales electronically, with all formulas intact for each month from 2013 to 2027.***

Response) In the MISO market, Big Rivers is paid by MISO for all its generation sold into the market and Big Rivers pays MISO for purchase of its entire load on an hourly basis. So in any given hour, Big Rivers is paid for the generation from Coleman 1, Coleman 2, Coleman 3, Green 1, etc. including the SEPA power. Each generator is paid at its individual price node (LMP). Therefore, the generation can be summed (in MW) and each generator's production can be multiplied by its respective LMP to calculate the gross revenue from MISO, and these gross revenues can be summed. On the load side, Big Rivers' total load (in MW) and total cost paid to MISO (product of load MW and load LMP) is calculated. If the load in MW is greater than the generation total, then the difference is a MISO net purchase for that hour and the cost of that purchase is the difference between the MISO cost and MISO

revenue. If the load in MW is less than the generation total, then the difference is a MISO net sale for that hour. This calculation is repeated for every hour.

On the Monthly Net Market Positions tab, the Sum of Net Purchases is the sum of all MISO net purchases (hours where the Big Rivers' load is greater than the sum of Big Rivers' generation) and the Sum of Net Sales is the sum of all MISO net sales (hours where Big Rivers' load is less than the sum of Big Rivers' generation).

The individual sales and purchases (hourly values) can be calculated from the CONFIDENTIAL electronic file provided in Big Rivers' response to KIUC 2-1(b) entitled "KIUC 2-1,PCM Run(May-13 to Dec-28) Hourly Values.xlsx".

Witness) Robert W. Berry

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Item 3) ***Provide the file - Summary of SEPA Charges 2013-2016.xlsx, which was referenced in row 72 of the Monthly Sources and Uses tab of the PCM file - Big Rivers PCM Run 4-22-13 (2013-2027).xlsx.***

Response) Please see the attached CONFIDENTIAL electronic file(s).

Witness) Robert W. Berry

Electronic Attachment(s) Produced Separately

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Item 4) ***Please explain and supply (electronically with all formula intact) the derivation of row 45 (HMPL Excess to BREC) of tab - Monthly Sources and Uses in the PCM file - Big Rivers PCM Run 4-22-13 (2013-2027).xlsx?*** [redacted]

[redacted]

Response) HMPL Excess to BREC in row 45 of the "Monthly Sources and Uses" tab shows the amount of excess energy (MWH) per the HMP&L capacity requirements for the city load. The formula takes the HMP&L city capacity requirement (115 MW for May, 2013) and multiplies by number of hours (744 in May, 2013) then subtracts the HMP&L load net of HMP&L SEPA (HMP&L load 425,076 MWH in May, 2013 less HMP&L SEPA 11,328 MWH in May, 2013). The calculation for May, 2013 is shown below:

(115 MW x 744 hours) – (425,076 MWH – 11,328 MWH) = 39,246 MWH.

The formula for the calculation is shown on the Annual Source and Uses tab in row 45.

[redacted]

[redacted]

Witness) Robert W. Berry

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Item 5) ***The Company's response to Staff 2-14 indicates that the ACES forward power market price projection was based on broker values that are updated daily for the near term. Please provide copies of the broker values that were used in the format that ACES received them in, and explain how they were acquired. Also, provide all workpapers that were used to derive the market price forecast that was entered into the production cost model covering the period 2013 to 2027. Please provide this information electronically with all formula intact.***

Response) Please see the attached letter from ACES to Big Rivers.

Witness) Robert W. Berry

September 20, 2013

Mr. Tyson Kamuf
Sullivan, Mountjoy, Stainback & Miller, P.S.C.
100 St. Ann Street
Owensboro, KY 42303

RE: Application of Big Rivers Electric Corporation for a General Adjustment in Rates
Case No. 2013-00199
Your Client: Big Rivers Electric Corporation

Dear Mr. Kamuf:

Recently, the Alliance for Cooperative Energy Services Power Marketing LLC ("ACES") received a request from Big Rivers Electric Corporation ("BREC") for assistance in responding to questions and data requests concerning the above referenced matter.

Please allow this correspondence to serve as ACES' formal response to your client's request for assistance in responding to the Kentucky Industrial Utility Customers, Inc.'s ("KIUC") Second Request for Information.

The KIUC's has requested in Item(s) 5 and 9 the broker values, work papers, data and the Wood Mackenzie "no carbon case" report. Please be advised that ACES licenses the use of this proprietary data under contract with the providers, of this requested data. ACES is unable to release the requested documents as they are confidential, propriety and in some instances the trade secrets of the licensor. For ACES to release these materials would constitute a violation of our license agreement for which ACES could be subject to penalty for breach of contract.

Please note that the requested reports and/or documents may be available to BREC or KIUC for purchase from the various sources identified in the KIUC's request.

Additionally, the KIUC has requested "...the hourly market forecast after making all changes necessary to prepare the date for entry into the PAR production cost model." ACES is able to provide this data and will submit this data as you direct.

Should you need anything additional, please do not hesitate to contact our offices.

Sincerely,

Wayne Harris
Chief Counsel

WH/bab

cc: Bob Berry

BIG RIVERS ELECTRIC CORPORATION

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Item 6) ***Why did Big Rivers believe it was important to rely on forward market price forecasts in Case No. 2012-00063 (Environmental Cost Recovery Case) that included CO2 impacts, but not in this proceeding?***

Response) Big Rivers objects that the words "important" and "not [important]" mischaracterize the testimony and discovery responses provided by Big Rivers in this matter. Notwithstanding this objection, and without waiving it, Big Rivers responds as follows.

In Case No. 2012-00063, Big Rivers used power market price forecasts from both ACES (which did not include CO_2 impacts) and PACE Global ("Pace"). Pace used a stochastic model that incorporated a range of market uncertainties and risks. This process included the development of 200 iterations of CO_2 allowance price projections that captured a range of possibilities for CO_2 prices, including the probability of no CO_2 prices, the probability of low CO_2 prices, and the probability of high CO_2 prices.

The forecasted power market prices Big Rivers relied on for this case are the ACES forecasted prices used in the development of the 2014-2015 financial forecast for use both in setting rates and in operations. As noted in Big Rivers' response to PSC 2-14, for this time period, the ACES price forecast incorporates broker values, which "represent actual prices at which counterparties in the market have transacted; thus, these are not 'projections' but are

actual market prices." Big Rivers believed it was appropriate to use actual market prices, where available, for purposes of the rate case.

Witness) Robert W. Berry

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Item 7) ***While some utilities incorporate impacts of CO2 costs in their planning analyses, Big Rivers has chosen not to.***

a. ***Why does Big Rivers consider its approach to be more reasonable?***

b. ***The Company's response to KIUC 1-16 appears to suggest that the Company only incorporates in its planning assumptions information that is known today. If this is true please explain why the Company has included an assumption that it would add 800 MW of new load over the study period.***

Response)

a. Big Rivers does consider the impact of potential CO_2 regulation as a sensitivity in its overall planning analyses, as described in its last Integrated Resource Plan (see Case No. 2010-00443). Big Rivers also monitors proposals related to the regulation of CO_2 emissions, and it considered the impact of such potential regulation on power market prices in its 2012 Environmental Compliance Plan proceeding (see Case No. 2012-00063).

Big Rivers did not assume an impact from potential CO_2 regulation on the forecasted power market prices used in the development of the forecasted test period, except to the extent that the anticipated impact from potential CO_2

regulation is already incorporated into the actual market prices used by ACES to develop the forecast that Big Rivers relied upon in this filing. This is reasonable for the reasons stated in Big Rivers' response to KIUC 2-6.

b. KIUC 1-16 asked about consistency between market price forecasts and the production cost forecasts with regard to assumptions such as "the effects of carbon regulation, CSAPR court rulings, and other assumptions that generally would be expected to affect both market prices and the Company's costs of owning and operating coal-fired capacity." Big Rivers' response to that question was intended to convey that for assumptions such as the effects of carbon regulation and CSAPR court rulings, both production costs and the "ACES power price projections [filed in this case] only include what is known today (CAIR remains in effect and MATS goes in effect in April, 2015)." The more general inference stated in the question is not true. Big Rivers includes in its budget and forecast the assumptions that it considers reasonable, reliable, made in good faith, and justified for use by management. The incremental load assumption meets these criteria for the reasons explained in Big Rivers' responses to KIUC 2-32 and SC 2-7.

BIG RIVERS ELECTRIC CORPORATION

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1 **Witness)** Robert W. Berry

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Item 8) *Company witness Barron's testimony at page 6, beginning at line 4 states that the RUS reviewed the Company's load forecast and that Big Rivers is currently awaiting approval.*

a. Please provide a copy of the Company's request/filing/application seeking RUS approval of the Company's load forecast. Provide a copy of all documents and analyses provided to the RUS in support of the application or in response to inquiries.

b. Provide a copy of the RUS approval when received and a copy of the RUS approval of the Company's most recent prior load forecast.

c. Please describe the RUS review and approval process and provide a copy of all legal and procedural requirements for such a review and approval process.

d. Please describe the purpose, significance and applicability of the RUS approval. Address the applicability for any known RUS purpose or the applicability to the Commission's ratemaking authority, if any.

e. Is it the Company's understanding that if the RUS approves the load forecast that in effect the RUS will approve the assumption that 800 MW of load will be added to the Big Rivers system during the study period in the

amounts and in the years reflected in the load forecast? If not, then identify which assumptions and components of the forecast the RUS approval will apply to and for what purpose(s).

Response)

a. Please see the attached document. Additionally, the Load Forecast document was provided to RUS and was attached to Big Rivers' response to AG 1-139.

b. Please see the attached document. RUS approval of Big Rivers' most recent prior load forecast was supplied as Exhibit Barron-2 in Case No. 2012-00535.

c. The RUS review and approval process may be found in the U.S. Code of Federal Regulations, Title 7, Chapter XVII, Part 1710, Subpart E, which is publically available from the U.S Government Printing Office website, www.gpo.gov.

d. To Big Rivers' knowledge, the purpose, significance and applicability of the RUS approval of a load forecast is described in the regulation referenced in subpart c of this response. To Big Rivers' knowledge, the applicability of a load forecast to the Commission's ratemaking authority is described in the Commission's regulations, in particular 807 KAR 5:001, Section 16.

e. Big Rivers' general understanding of the use made by RUS of Big Rivers' load forecast is described in the regulation referenced in Big Rivers' response to subpart (c) of this response. In addition, in the RUS approval letter attached to Big Rivers' response to subpart (b), RUS stated that "[the methods and assumptions used are reasonable."

Witnesses) Lindsay N. Barron, John Wolfram

Big Rivers
ELECTRIC CORPORATION

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

May 3, 2013

Mr. Gerard M. Moore
Branch Chief – Energy Forecasting
Rural Development | Rural Utilities Service | Electric Program
U.S. Department of Agriculture Mail Stop 1569
1400 Independence Avenue, S.W.
Washington, DC 20250

Re: Big Rivers Electric Corporation
Updated 2013 Load Forecast

Dear Gerry:

Big Rivers is submitting an updated 2013 Load Forecast for approval by the RUS as required by regulation (7 CFR 1710). I have enclosed two copies of Big Rivers Electric Corporation's updated 2013 Load Forecast and Load Forecast Work Plan as well as an excerpt from the minutes of the Big Rivers' Board of Directors meeting approving the Load Forecast and Work Plan.

Thank you for your assistance in this matter. Please let me know if you have any questions.

Sincerely,

Big Rivers Electric Corporation

Lindsay N. Barron
Vice President Energy Services

Enclosures

C: Mr. Mark A. Bailey
Mr. Robert W. Berry
Ms. Billie J. Richert
Mr. Nicholas R. Castlen
Mr. James M. Miller

EXCERPT FROM THE MINUTES OF REGULAR MEETING OF THE BOARD OF DIRECTORS OF BIG RIVERS ELECTRIC CORPORATION HELD IN HENDERSON, KENTUCKY, ON APRIL 19, 2013

After a presentation by Lindsay Barron at the April 18 work session and upon management's recommendation, Director Denton moved that the 2013 Load Forecast and Load Forecast Work Plan be approved. The motion was seconded and unanimously adopted.

I, Paula Mitchell, Executive Secretary of the Board of Directors of Big Rivers Electric Corporation, hereby certify that the above is a true and correct excerpt from the minutes of the Regular Meeting of the Board of Directors of said Corporation held on 4-19-13.

Paula Mitchell

Big Rivers Electric Corporation

Henderson, Kentucky

2013 Load Forecast Work Plan

Big Rivers Electric Corporation

Kenergy Corp.

Jackson Purchase Energy Corporation

Meade County Rural Electric Cooperative Corporation

Prepared by

GDS Associates, Inc.

Table of Contents

1. Introduction

This document presents the work plan developed for developing the 2013 Load Forecast for Big Rivers and its three member distribution cooperatives, including Kenergy Corp, Jackson Purchase Energy Corporation, and Meade County Rural Electric Cooperative Corporation. The Work Plan addresses the current guidelines established by the Rural Utilities Service (RUS)[1]. This report is organized in five sections:

1. Introduction
2. Scope of Work
3. Project Outputs
4. Project Schedule
5. Project Team and Resources

The load forecasts developed during 2013 will provide projections of power requirements needed by Big Rivers and its member cooperatives for system and financial planning studies that will be conducted over the next two years. The load forecast will be presented in report form, including tables and charts exhibiting the energy and demand projections, a discussion of the forecast assumptions, and a description of the methodologies employed in developing the forecast. Upon final review and approval of the forecast by RUS, copies of the final 2013 Load Forecast will be distributed to Big Rivers and the member cooperatives.

The forecasts will be prepared during the February through July 2013 period. All preliminary discussions regarding the forecast will be completed by telephone. Meetings will be held at Big Rivers, or another agreed upon location, to review the preliminary forecasts, revise the projections as necessary, and to gain cooperative management and RUS agreement prior to preparing the final reports. All forecasts will be completed by July 31, 2013.

A project team will be assembled to work together in developing the forecasts. The team will consist of representatives from each member cooperative, Big Rivers, GDS Associates, and RUS. Big Rivers staff will be responsible for project oversight and coordination. GDS Associates will be responsible for developing the forecasting models upon which the forecasts are based and preparation of the final reports. The member cooperative team representatives will be responsible for reviewing their respective forecasts and insuring reasonableness of the forecast assumptions and resulting power requirements projections. RUS staff will be responsible for reviewing the forecasts and verifying that the studies were completed in accordance with RUS guidelines.

[1] Federal Register, January 1, 2006, Department of Agriculture, Rural Utilities Services, CFR, Title 7, Volume 11, Part 1710, http://www.usda.gov/rus/electric/regs/2006/1710.htm

2. Scope of Work

This section presents the tasks that will be completed in association with the project. The scope of work is in accordance with the current RUS guidelines as specified in 7 CFR Part 1710.

In 1995, Big Rivers began a process of updating its load forecast on a two-year cycle. The 2013 Load Forecast will represent the eleventh study completed under that planning cycle. The scope of work is based on econometric modeling technique and includes many of the same processes employed in the 2011 Load Forecast Work Plan, which was approved for use by RUS.

2.1 Load Forecast Database Updates

Big Rivers will provide to GDS copies of all database files developed during the 2011 Load Forecast. GDS will be responsible for updating the electronic files while Big Rivers will be responsible for collecting and providing various data to GDS. The data requirements for the project as listed as follows:

2.1.1 RUS Form 7

Big Rivers and the member cooperatives will be responsible for collecting and providing the 2011 and 2012 year-end Form 7 for each member system. GDS will update the existing electronic files, which contain system data on a monthly basis for years 1970 - 2010.

2.1.2 Large Commercial & Industrial Customer Data

Big Rivers and the member cooperatives will be responsible for collecting and providing updated demand and energy (monthly) for each account that has transformer capacity greater than 1,000 kVa. GDS will provide an electronic template to each member system for providing the data. Attention will be given to accounts with peak demands that have grown from less than 1,000 kW in historical years to expected amounts greater than 1,000 kW during the forecast period, and vice-versa.

2.1.3 EEI Hourly Load Data

Big Rivers will be responsible for providing, in electronic form, the 2011-2012 hourly loads for the Big Rivers system.

2.1.4 Rural System and Direct Serve Energy Sales and Peak Demand [2]

Big Rivers will be responsible for providing in electronic form rural system energy sales and peak demand on a monthly basis for each member cooperative and for Big Rivers.

[2] Rural system requirements are defined as total system requirements less those requirements corresponding to large commercial and industrial customers served from dedicated points of delivery. Direct serve is defined as any large commercial and industrial customers that are served directly from a dedicated point of delivery.

2.1.5 Climatological Reports

GDS will be responsible for collecting the Local Climatological Data Monthly Summary reports for Evansville, Indiana; Paducah, Kentucky; and Louisville, Kentucky for any periods for which data are not already available.

2.1.6 Economic Data

GDS will be responsible for obtaining historical and projected economic data, which will be collected from Moody's Analytics.

2.1.7 Wholesale Power Cost Forecast

Big Rivers will be responsible for developing projections of wholesale power cost and estimated increases in the price of rural system energy at the retail level.

2.2 Weather Normalization

Weather normalized energy sales and peak demand values for each member cooperative will be computed for historical years. The normalized values will provide a basis for computing weather normalized growth for future years.

2.3 Short-Term Forecast Development

A short-term peak demand and energy sales forecast will be prepared for Big Rivers and for each individual member cooperative. Projections will be developed on a monthly basis for years 2013-2017. Energy sales and peak demand will be projected by customer classification and aggregated to the Big Rivers level. The Big Rivers short-term forecast will also include, by member distribution cooperative, the following components: (1) monthly energy and demand requirements for each individual direct serve customer and (2) rural system energy and demand requirements.

Regression analysis will be utilized as the primary short-term forecasting methodology. Regression models will be developed to project rural system energy sales. Input from cooperative management and from industrial customers will be used in developing forecasts for each direct serve industrial customer. Regression analysis or historical trends will be used to break the rural system sales forecast down by member cooperative retail class. Econometrics provides the means quantifying the impacts of the following influential factors on energy consumption and customer growth:

- Number of households
- County household market share
- Real average household income
- Real price of electricity
- Market share of electric heating and air conditioning
- Appliance efficiencies of electric heating and air conditioning
- Heating and cooling degree days

A regression model will be developed to project rural system CP demand at the Big Rivers level. The model will be based on the following inputs:

- Rural system energy requirements
- Average temperature on the peak day
- Average temperature on the two days prior to the peak day
- Monthly binary variables, as deemed appropriate

Historical ratios will be used to allocate the Big Rivers rural CP demand forecast down to the member system level. A diversity factor will be applied to each member cooperative's contribution to the Big Rivers peak to produce each cooperative's respective one-hour rural system peak.

2.4 Long-Term Forecast Development

A long-term peak demand and energy sales forecast will be prepared for Big Rivers and each individual member distribution cooperative. The forecast period will be 2013-2028. The energy sales forecast will be presented on an annual, customer class basis. Coincident and non-coincident peak demand will be projected on an annual basis and include both summer and winter season amounts. The total system peak demand forecast will be broken down into the rural system and direct serve components. A base case forecast, plus scenarios to address optimistic/pessimistic economic conditions and extreme/mild weather conditions, will be provided.

Econometrics will be utilized as the primary forecasting methodology in development of the long-term forecast. Models will be developed to project the number of rural system customers, rural system average use per customer, and rural system peak demand. Energy sales and peak demand for all direct serve customers will be developed individually for each account based upon historical trends and input received from cooperative management. Consumer and energy models will be developed for each member cooperative. Rural system energy sales for each cooperative will be broken down to residential, small commercial, public building, public street lighting, and irrigation sales, as applicable, based on historical ratios.

Projections of rural system peak demand for Big Rivers in years 2013-2017 will be based on the regression model developed to produce the monthly forecast described in Section 2.3. Projections will be broken down to the member cooperative level using historical ratios. For years 2018-2028, rural system demand for each member cooperative will be based on rural system energy requirements and the derived load factor for 2017. A diversity factor will be applied to each member system's contribution to the Big Rivers one-hour rural CP demand to produce a one-hour member cooperative NCP. A second diversity factor will be applied to each member cooperative's one-hour NCP to produce a NCP demand that represents the sum of point of delivery NCPs. Member CP demand projections for 2018-2028 will be aggregated to produce the Big Rivers forecast of rural system peak demand.

2.5 Development and Review of the Forecast

Forecasts will be developed for each member cooperative based upon their respective short-term and long-term forecasts. Each member cooperative will be responsible for approving their respective forecasts. Representatives from the load forecast planning

committee, GDS, and RUS will meet, or teleconference, to review the projections. Upon presentation and review of the forecasts, revisions, if necessary, will be made at the meetings in efforts to obtain cooperative management and RUS GFR approval. The review will focus on the following items:

1. Recent history of demand, energy, number of consumers, consumer classes, and growth rates;
2. Land use, energy alternatives, wholesale power cost, known structural changes;
3. Trends in load mix, load factor, system losses;
4. Impacts of the model input variables;
5. Base case forecasts;
6. Load factor/peak demand projections;
7. Power requirements projections;
8. Load forecast documentation.

2.6 Member Cooperative Approval: Projections

Load forecast reports will be prepared based on the projections finalized at the review meetings. Reports, which will present the forecast for years 2013-2028, will be provided to each system for review and comment. Each report will address the following items:

1. Cooperative background/service area narrative;
2. Load forecast database;
3. Economic outlook;
4. Energy Efficiency/DSM;
5. Forecast assumptions;
6. Short-term forecast;
7. Long-term forecast;
8. Range forecasts;
9. Forecast methodology;
10. Forecast tables.

2.7 Board of Director Approval

Upon provisional RUS approval of the load forecasts, copies of the reports will be presented to each cooperative's Board of Directors for final approval.

3. Project Outputs

3.1 Preliminary Load Forecast Reports

Each member system will be provided draft copies of their respective load forecast report one week prior to the review sessions. These reports will include documentation for those items identified above in Section 2.6.

3.2 Final Load Forecast Reports

Upon completion of forecasts, revisions to the draft load forecast reports will be incorporated into the final drafts of the member system and Big Rivers load forecast reports.

3.3 Electronic Files

Big Rivers will be provided the electronic files created in developing the forecasts, including the economic outlook, the model input data, the model specifications and associated statistics, and the final reports.

4. Project Schedule

The load forecasts will be completed over the February 2013-July 2013 period. The schedule includes the following key tasks:

1. Project awarded by Big Rivers
2. Load Forecast Work Plan developed and approved
3. Data collection
4. Development of economic outlook
5. Model development
6. Development of preliminary forecasts
7. Review forecasts
8. Provisional approval by cooperative management
9. Delivery of final reports
10. Board approvals
11. RUS review and approval

5. Project Team and Resources

The resources necessary for Big Rivers and its member cooperatives to complete the load forecast project include qualified personnel, reliable data, and appropriate computer facilities.

5.1 Project Team

The project team will include representatives from Big Rivers Electric Corporation, each member cooperative, GDS Associates, and RUS. Oversight of the project is assigned to Big Rivers. Big Rivers and the member cooperatives will provide data and input into the development of the forecast assumptions and review of the forecasts. GDS Associates will complete the modeling and tasks required for producing the respective forecasts. RUS will review the forecasts and forecasting process to insure that they comply with RUS guidelines. Project team members will be responsible for the timely completion of tasks specifically assigned to them, including providing data, providing input into the development of forecast assumptions, reviewing the forecasts, and addressing any unforeseen issues that may arise during the project. Table 5.1 presents the project team.

Table 5.1
Project Team

Name	Company	Phone Number
Lindsay Barron	Big Rivers Electric Corporation	270-827-2561
Mike Mattox		
Eric Hebble		
Steve Thompson	Kenergy Corp.	270-826-3991
John Newland		
Chuck Williamson	Jackson Purchase Energy Corporation	270-441-0856
David Poe	Meade County Rural Electric Cooperative, Corporation	270-422-2162
Karen Brown		
John Hutts	GDS Associates, Inc.	770-425-8100
Jacob Thomas		
Gerard Moore	Rural Utilities Service	202-720-1920
Georg Shultz		

Data Requirements - The data requirements for this project are discussed in the Scope of Work, Section 2.1, Load Forecast Database Updates.

Computer Resources - All work requiring computer facilities will be conducted using PCs (IBM compatible). Microsoft Office products will be used for spreadsheet analysis, work processing, and graphics. Statistical Analysis System (SAS), MetrixND, and Excel are available for statistical analyses. All project files will be provided Big Rivers and the member cooperatives via CD.

Big Rivers Electric Corporation

Henderson, Kentucky

2013 Load Forecast Work Plan

Big Rivers Electric Corporation

Kenergy Corp.

Jackson Purchase Energy Corporation

Meade County Rural Electric Cooperative Corporation

Prepared by

GDS Associates, Inc.

Table of Contents

1. Introduction

This document presents the work plan developed for developing the 2013 Load Forecast for Big Rivers and its three member distribution cooperatives, including Kenergy Corp, Jackson Purchase Energy Corporation, and Meade County Rural Electric Cooperative Corporation. The Work Plan addresses the current guidelines established by the Rural Utilities Service (RUS)[1]. This report is organized in five sections:

1. Introduction
2. Scope of Work
3. Project Outputs
4. Project Schedule
5. Project Team and Resources

The load forecasts developed during 2013 will provide projections of power requirements needed by Big Rivers and its member cooperatives for system and financial planning studies that will be conducted over the next two years. The load forecast will be presented in report form, including tables and charts exhibiting the energy and demand projections, a discussion of the forecast assumptions, and a description of the methodologies employed in developing the forecast. Upon final review and approval of the forecast by RUS, copies of the final 2013 Load Forecast will be distributed to Big Rivers and the member cooperatives.

The forecasts will be prepared during the February through July 2013 period. All preliminary discussions regarding the forecast will be completed by telephone. Meetings will be held at Big Rivers, or another agreed upon location, to review the preliminary forecasts, revise the projections as necessary, and to gain cooperative management and RUS agreement prior to preparing the final reports. All forecasts will be completed by July 31, 2013.

A project team will be assembled to work together in developing the forecasts. The team will consist of representatives from each member cooperative, Big Rivers, GDS Associates, and RUS. Big Rivers staff will be responsible for project oversight and coordination. GDS Associates will be responsible for developing the forecasting models upon which the forecasts are based and preparation of the final reports. The member cooperative team representatives will be responsible for reviewing their respective forecasts and insuring reasonableness of the forecast assumptions and resulting power requirements projections. RUS staff will be responsible for reviewing the forecasts and verifying that the studies were completed in accordance with RUS guidelines.

[1] Federal Register, January 1, 2006, Department of Agriculture, Rural Utilities Services, CFR, Title 7, Volume 11, Part 1710, http://www.usda.gov/rus/electric/regs/2006/1710.htm

2. Scope of Work

This section presents the tasks that will be completed in association with the project. The scope of work is in accordance with the current RUS guidelines as specified in 7 CFR Part 1710.

In 1995, Big Rivers began a process of updating its load forecast on a two-year cycle. The 2013 Load Forecast will represent the eleventh study completed under that planning cycle. The scope of work is based on econometric modeling technique and includes many of the same processes employed in the 2011 Load Forecast Work Plan, which was approved for use by RUS.

2.1 Load Forecast Database Updates

Big Rivers will provide to GDS copies of all database files developed during the 2011 Load Forecast. GDS will be responsible for updating the electronic files while Big Rivers will be responsible for collecting and providing various data to GDS. The data requirements for the project as listed as follows:

2.1.1 RUS Form 7

Big Rivers and the member cooperatives will be responsible for collecting and providing the 2011 and 2012 year-end Form 7 for each member system. GDS will update the existing electronic files, which contain system data on a monthly basis for years 1970 - 2010.

2.1.2 Large Commercial & Industrial Customer Data

Big Rivers and the member cooperatives will be responsible for collecting and providing updated demand and energy (monthly) for each account that has transformer capacity greater than 1,000 kVa. GDS will provide an electronic template to each member system for providing the data. Attention will be given to accounts with peak demands that have grown from less than 1,000 kW in historical years to expected amounts greater than 1,000 kW during the forecast period, and vice-versa.

2.1.3 EEI Hourly Load Data

Big Rivers will be responsible for providing, in electronic form, the 2011-2012 hourly loads for the Big Rivers system.

2.1.4 Rural System and Direct Serve Energy Sales and Peak Demand [2]

Big Rivers will be responsible for providing in electronic form rural system energy sales and peak demand on a monthly basis for each member cooperative and for Big Rivers.

[2] Rural system requirements are defined as total system requirements less those requirements corresponding to large commercial and industrial customers served from dedicated points of delivery. Direct serve is defined as any large commercial and industrial customers that are served directly from a dedicated point of delivery.

2.1.5 Climatological Reports

GDS will be responsible for collecting the Local Climatological Data Monthly Summary reports for Evansville, Indiana; Paducah, Kentucky; and Louisville, Kentucky for any periods for which data are not already available.

2.1.6 Economic Data

GDS will be responsible for obtaining historical and projected economic data, which will be collected from Moody's Analytics.

2.1.7 Wholesale Power Cost Forecast

Big Rivers will be responsible for developing projections of wholesale power cost and estimated increases in the price of rural system energy at the retail level.

2.2 Weather Normalization

Weather normalized energy sales and peak demand values for each member cooperative will be computed for historical years. The normalized values will provide a basis for computing weather normalized growth for future years.

2.3 Short-Term Forecast Development

A short-term peak demand and energy sales forecast will be prepared for Big Rivers and for each individual member cooperative. Projections will be developed on a monthly basis for years 2013-2017. Energy sales and peak demand will be projected by customer classification and aggregated to the Big Rivers level. The Big Rivers short-term forecast will also include, by member distribution cooperative, the following components: (1) monthly energy and demand requirements for each individual direct serve customer and (2) rural system energy and demand requirements.

Regression analysis will be utilized as the primary short-term forecasting methodology. Regression models will be developed to project rural system energy sales. Input from cooperative management and from industrial customers will be used in developing forecasts for each direct serve industrial customer. Regression analysis or historical trends will be used to break the rural system sales forecast down by member cooperative retail class. Econometrics provides the means quantifying the impacts of the following influential factors on energy consumption and customer growth:

- Number of households
- County household market share
- Real average household income
- Real price of electricity
- Market share of electric heating and air conditioning
- Appliance efficiencies of electric heating and air conditioning
- Heating and cooling degree days

A regression model will be developed to project rural system CP demand at the Big Rivers level. The model will be based on the following inputs:

- Rural system energy requirements
- Average temperature on the peak day
- Average temperature on the two days prior to the peak day
- Monthly binary variables, as deemed appropriate

Historical ratios will be used to allocate the Big Rivers rural CP demand forecast down to the member system level. A diversity factor will be applied to each member cooperative's contribution to the Big Rivers peak to produce each cooperative's respective one-hour rural system peak.

2.4 Long-Term Forecast Development

A long-term peak demand and energy sales forecast will be prepared for Big Rivers and each individual member distribution cooperative. The forecast period will be 2013-2028. The energy sales forecast will be presented on an annual, customer class basis. Coincident and non-coincident peak demand will be projected on an annual basis and include both summer and winter season amounts. The total system peak demand forecast will be broken down into the rural system and direct serve components. A base case forecast, plus scenarios to address optimistic/pessimistic economic conditions and extreme/mild weather conditions, will be provided.

Econometrics will be utilized as the primary forecasting methodology in development of the long-term forecast. Models will be developed to project the number of rural system customers, rural system average use per customer, and rural system peak demand. Energy sales and peak demand for all direct serve customers will be developed individually for each account based upon historical trends and input received from cooperative management. Consumer and energy models will be developed for each member cooperative. Rural system energy sales for each cooperative will be broken down to residential, small commercial, public building, public street lighting, and irrigation sales, as applicable, based on historical ratios.

Projections of rural system peak demand for Big Rivers in years 2013-2017 will be based on the regression model developed to produce the monthly forecast described in Section 2.3. Projections will be broken down to the member cooperative level using historical ratios. For years 2018-2028, rural system demand for each member cooperative will be based on rural system energy requirements and the derived load factor for 2017. A diversity factor will be applied to each member system's contribution to the Big Rivers one-hour rural CP demand to produce a one-hour member cooperative NCP. A second diversity factor will be applied to each member cooperative's one-hour NCP to produce a NCP demand that represents the sum of point of delivery NCPs. Member CP demand projections for 2018-2028 will be aggregated to produce the Big Rivers forecast of rural system peak demand.

2.5 Development and Review of the Forecast

Forecasts will be developed for each member cooperative based upon their respective short-term and long-term forecasts. Each member cooperative will be responsible for approving their respective forecasts. Representatives from the load forecast planning

committee, GDS, and RUS will meet, or teleconference, to review the projections. Upon presentation and review of the forecasts, revisions, if necessary, will be made at the meetings in efforts to obtain cooperative management and RUS GFR approval. The review will focus on the following items:

1. Recent history of demand, energy, number of consumers, consumer classes, and growth rates;
2. Land use, energy alternatives, wholesale power cost, known structural changes;
3. Trends in load mix, load factor, system losses;
4. Impacts of the model input variables;
5. Base case forecasts;
6. Load factor/peak demand projections;
7. Power requirements projections;
8. Load forecast documentation.

2.6 Member Cooperative Approval: Projections

Load forecast reports will be prepared based on the projections finalized at the review meetings. Reports, which will present the forecast for years 2013-2028, will be provided to each system for review and comment. Each report will address the following items:

1. Cooperative background/service area narrative;
2. Load forecast database;
3. Economic outlook;
4. Energy Efficiency/DSM;
5. Forecast assumptions;
6. Short-term forecast;
7. Long-term forecast;
8. Range forecasts;
9. Forecast methodology;
10. Forecast tables.

2.7 Board of Director Approval

Upon provisional RUS approval of the load forecasts, copies of the reports will be presented to each cooperative's Board of Directors for final approval.

3. Project Outputs

3.1 Preliminary Load Forecast Reports

Each member system will be provided draft copies of their respective load forecast report one week prior to the review sessions. These reports will include documentation for those items identified above in Section 2.6.

3.2 Final Load Forecast Reports

Upon completion of forecasts, revisions to the draft load forecast reports will be incorporated into the final drafts of the member system and Big Rivers load forecast reports.

3.3 Electronic Files

Big Rivers will be provided the electronic files created in developing the forecasts, including the economic outlook, the model input data, the model specifications and associated statistics, and the final reports.

4. Project Schedule

The load forecasts will be completed over the February 2013-July 2013 period. The schedule includes the following key tasks:

1. Project awarded by Big Rivers
2. Load Forecast Work Plan developed and approved
3. Data collection
4. Development of economic outlook
5. Model development
6. Development of preliminary forecasts
7. Review forecasts
8. Provisional approval by cooperative management
9. Delivery of final reports
10. Board approvals
11. RUS review and approval

5. Project Team and Resources

The resources necessary for Big Rivers and its member cooperatives to complete the load forecast project include qualified personnel, reliable data, and appropriate computer facilities.

5.1 Project Team

The project team will include representatives from Big Rivers Electric Corporation, each member cooperative, GDS Associates, and RUS. Oversight of the project is assigned to Big Rivers. Big Rivers and the member cooperatives will provide data and input into the development of the forecast assumptions and review of the forecasts. GDS Associates will complete the modeling and tasks required for producing the respective forecasts. RUS will review the forecasts and forecasting process to insure that they comply with RUS guidelines. Project team members will be responsible for the timely completion of tasks specifically assigned to them, including providing data, providing input into the development of forecast assumptions, reviewing the forecasts, and addressing any unforeseen issues that may arise during the project. Table 5.1 presents the project team.

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Project Team

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Georg Shultz		

Data Requirements - The data requirements for this project are discussed in the Scope of Work, Section 2.1, Load Forecast Database Updates.

Computer Resources - All work requiring computer facilities will be conducted using PCs (IBM compatible). Microsoft Office products will be used for spreadsheet analysis, work processing, and graphics. Statistical Analysis System (SAS), MetrixND, and Excel are available for statistical analyses. All project files will be provided Big Rivers and the member cooperatives via CD.

USDA Rural Development

United States Department of Agriculture
Rural Development

JUN 26 2013

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

Dear Mr. Bailey:

We have reviewed the 2013 Load Forecast Update (Forecast) for Big Rivers Electric Corporation, Inc. (Big Rivers) and its members. The studies and board resolutions were submitted to the Rural Utilities Service (RUS) on May 6, 2013, and prepared pursuant to the 2013 Work Plan approved by the agency on May 16, 2013. The methods and assumptions used are reasonable. The Forecast was effectively coordinated with all of Big Rivers' members. A certified resolution dated April 18, 2013, from Big Rivers' Board of Directors approving the Forecast and its uses, was submitted to RUS.

This letter documents RUS approval of Big Rivers' 2013 Forecast. Member studies developed in coordination with this Forecast are also approved. The agency will consider the 2013 studies current, pursuant to 7 CFR 1710 Subpart E, Load Forecasts. Big Rivers and its members must use these Forecasts in all engineering, environmental, financial studies, financial forecasts, and in any studies in support of loan applications.

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

Sincerely,

LOUIS RIGGS
Acting Director
Electric Staff Division
Rural Utilities Service

Mr. Mark A. Bailey

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

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

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

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

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
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Item 9) ***The Company's response to PSC 2-14 states that Wood Mackenzie's no carbon case was used in the development of the forward market price forecast and that a new update is expected anytime. Please provide the new update when it is available exactly as received from Wood Mackenzie, and also supply the hourly market forecast after making all changes necessary to prepare the data for entry into the PAR production cost model. This data should contain all of the standard adjustments that the Company ordinarily makes to prepare the data for production cost modeling. Please provide this hourly for the entire 2014 - 2027 study period, and provide it electronically with all formula intact. Also, please supply all workpapers, electronically with all formula intact, used in the conversion of the market price data from the format received from Wood Mackenzie to the format required for entry into the PAR model. Also, please supply the Wood Mackenzie gas price forecast, electronically, consistent with this market price forecast.***

Response) The Woods Mackenzie no carbon prices were updated on 8/28/13. Please see the letter attached to Big Rivers' response to KIUC 2-5. ACES IN Hub power price forecasts were pulled from the ACES web site dated 9/19/13 that uses the updated Woods Mackenzie forecasts. The data on the ACES web site provides monthly on and off peak values along

with monthly ATC values. These monthly ATC values were averaged to estimate annual averages. These annual averages were then included (added) to the CONFIDENTIAL table included in Big Rivers' response to PSC 2-14. Please see the CONFIDENTIAL electronic attachment to this response.

Big Rivers does not have the hourly price forecasts for this update. Please see Big Rivers' response to AG 2-51. Big Rivers does not have the Woods Mackenzie gas price forecast. Please see the letter attached to Big Rivers' response to KIUC 2-5.

Witness) Robert W. Berry

Electronic Attachment(s) Produced Separately

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Item 10) ***The Company referred to Hedged Fuel, Contract Fuel, and Spot Fuel in its response to KIUC 1-12. Please explain the differences between each of these, and how the different fuel prices were used in the analyses the Company performed.***

Response) The reference to hedged fuel and contract fuel in Big Rivers' response to KIUC 1-12 are synonymous. Big Rivers procures a certain percentage of its fuel needs for up to a five-year period via fuel supply contracts. Thus, fuel supply contracts serve as a physical fuel hedge, or hedged fuel, for the Company. In planning and forecasting future pricing for fuel, the contracted fuel pricing is used per the Base Price per year for the Base Quantity assigned within the contract, along with contractual transportation charges. This is the known portion of pricing for the forecast.

Spot or open position fuel is/are forecasted requirements for fuel supply and transportation that have yet to be procured or under contract. For forecasting purposes, Big Rivers will review coal forecasts and journals to which it subscribes, along with current market information via coal bid responses, to formulate a forecasted future price for coal yet to be procured. In this forecast, Big Rivers utilized forecasted market pricing from: ACES Power Marketing (which is an ACES in-house consolidated near term coal forecast supplied by ICAP Energy, along with a longer term forecast supplied by Wood/MacKenzie); Argus

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Coal Daily physical market assessment for coal pricing; Coal Trader/Outlook coal forecast; and, J.D. Energy coal forecast subscription. For the time period of this evaluation, Big Rivers did not have any current market bid solicitation data to utilize for the forward forecast. The last market solicitation for term coal supply was issued by Big Rivers in September and received in October 2012 and was too dated (five to six months aged) for this evaluation. The next term solicitation for coal procurement was not received until May 31, 2013.

Also, in regard to transportation, Big Rivers' barge contractual agreement expires December 31, 2013. In this evaluation, Big Rivers utilized a basis of $[redacted]/ton (with [redacted]% year-to-year escalation, to include diesel fuel escalation) for its transportation forecast.

For examples of the various journals and calculation of spot / open position pricing, please see Big Rivers' response to AG 2–57.

Witness) Robert W. Berry

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Item 11) ***The 2016/2017 Base Residual Auction in PJM resulted in a Resource Clearing Price for the RTO of $59.37/MW-day, which is about $1.78/kW-month (http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2016-2017-base-residual-auction-report.ashx). If PJM prices are so low, please provide the economic rationale explaining why the MISO Capacity Market Prices for ACES, Wood Mackenzie, IHS Global, would be so much higher (around [redacted] for the same time period per the response to KIUC 1-13). Why wouldn't capacity owners in PJM offer capacity in the MISO market, which would then drive down prices in MISO and bring prices between MISO and PJM closer together.***

Response) Big Rivers relies on experts, like Wood Mackenzie and IHS Global, to project future market prices. It is, however, important to note that if PJM capacity owners sold their capacity in the PJM 2016/2017 Auction in 2013, they would not have capacity available to sell in MISO when the 2016/2017 MISO Auction occurs in early 2016. MISO's current auctions are conducted several months prior to the start of the MISO Planning Year; thus there is currently a significant disconnect in the timing of these two auctions. PJM owners who have already committed their capacity in the PJM Auction will be unable to take advantage of the MISO market until the 2017/2018 planning year. Also, please note that

there is a physical electrical transfer limit between PJM and MISO; thus, firm transmission capacity is not always available between the two markets to allow capacity auction participation.

Witness) Robert W. Berry

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Item 12) ***Where in the Company's analysis does the market capacity cost appear? Please provide the spreadsheet, worktab and cell location.***

Response) The financial model filed as the base case in this proceeding does not specifically include market capacity revenues; however, Big Rivers has performed sensitivities which include these projected revenues. The sensitivities were provided in this proceeding as "Financial Forecast (2014-2026) 8-15-2013 (capacity market base case).xlsx" and "Financial Forecast (2014-2026) 8-15-2013 (capacity market 50%).xlsx," attached to Big Rivers' response to PSC 2-14. Details regarding these files are discussed in Big Rivers' response to KIUC 2-13.

Witness) Robert W. Berry

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Item 13) ***The following 3 long-term financial forecasts were supplied:***

Financial Forecast (2014-2017) 5-16-2013 (Filed Confidential).xlsx

Financial Forecast (2014-2026) 8-15-2013 (capacity market 50%).xlsx

Financial Forecast (2014-2026) 8-15-2013 (capacity market base case).xlsx

Please identify and describe the differences in assumptions and data among the forecasts and describe the purpose and use of each forecast.

Response) The forecast "Financial Forecast (2014-2017) 5-16-2013 (Filed Confidential).xlsx" was developed for CN 2013-00199 and provided in PSC 1-57. The assumptions to create this case and outputs from the case are discussed throughout the witness testimony, filing requirements for the case, and in response to data requests. The sensitivities titled "Financial Forecast (2014-2026) 8-15-2013 (capacity market 50%).xlsx" and "Financial Forecast (2014-2026) 8-15-2013 (capacity market base case).xlsx" were provided in response to PSC 2-14. These sensitivities were performed to quantify the financial benefit to Big Rivers' Members of projected MISO capacity prices. The capacity market base case used capacity market price projections as of May 31, 2013 from Wood Mackenzie. The capacity market 50% scenario was performed to validate that participating in the capacity market would remain beneficial even if the price was 50% of the

base case projection. In both sensitivities the Wilson and Coleman units are operated in 2016 and significant benefits are experienced by Big Rivers' Members as a result of plant operation and the sale of capacity and energy into the market.

Witness) Christopher A. Warren

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Item 14) ***Concerning the following 2 production cost results files that were supplied:***

Big Rivers PCM Run 4-22-13 (2013-2027).xlsx

Big Rivers PCM Run All Running 4-22-13 (2013-2027).xlsx

Please identify and describe the differences in assumptions and data among the forecasts and describe the purpose and use of each of these production cost results.

Response) "Big Rivers PCM Run 4-22-13 (2013-2027).xlsx" is the production cost model run used for this rate case (Case No. 2013-00199). In this PCM run, Wilson Station is idled from September, 2013 through May, 2018 and Coleman Station is idled from February, 2014 through July, 2019. "Big Rivers PCM Run All Running 4-22-13 (2013-2027).xlsx" does not idle any generation. This "All Running" PCM Run is used to analyze when to idle and when to return the generation station back to service. The PCM Run determines the gross margins the generating station earns on the variable cost side. These gross margins can be compared with the fixed cost savings from idling a generating station. If the fixed cost savings are greater than the variable cost net margins, then the generating station should remain idled. If the variable cost gross margins are greater, then the generating station should be restarted.

All assumptions and inputs are identical except for the following items. The fuel pricing is different in the 2013 to 2016 time frame due to Big Rivers' current fuel contracts. In the "All Running" model, Big Rivers will be purchasing fuel on the spot market (or will be in the market to procure additional term contracts) while the "Big Rivers PCM Run 4-22-13 (2013-2027)" is nearly 100% hedged with existing coal contracts. Finally, the outage schedule is slightly different due to idled generating units and dates when they are expected to be brought back into service.

Witness) Robert W. Berry

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Item 15) ***Please supply the same revenue requirement information as supplied in response to KIUC 1-21 and 1-22 (for Wilson and Coleman), but for the entire period of 2014 through 2027. Please supply this electronically with all formula intact.***

Response) Please see the attached CONFIDENTIAL electronic file which shows the costs for Wilson and Coleman from 2014 through 2027.

Witness) Jeffrey R. Williams

Electronic Attachment(s) Produced Separately

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Item 16) ***The Company's response to KIUC 1-46 states that the run attached to PSC 2-14 shows Coleman and Wilson idled, then profitably back in service in May 2018 and July 2019 respectively. Please provide, or specify where the Company already provided, the Company's analysis showing that Wilson and Coleman are profitably back in service on the dates specified. Please provide a narrative explanation of how the economic evaluation was performed that shows this.***

Response) Wilson and Coleman are idled, and then profitably back in service in May 2018 and July 2019 in the "Financial Forecast (2014-2027) 5-16-2013.xlsx" run attached to PSC 2-14. The units were brought back in service to serve the projected load for the system. A series of rate decreases for the members are also forecasted after 2019 due to the additional margins received from operating these units. Please note, in the sensitivities "Financial Forecast (2014-2026) 8-15-2013 (capacity market 50%).xlsx" and "Financial Forecast (2014-2026) 8-15-2013 (capacity market base case).xlsx" provided in response to PSC 2-14, assuming the capacity prices projected by Wood Mackenzie, the units are back and providing significant Member benefit in 2016.

Witness) Robert W. Berry

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Item 17) ***See file = Financial Forecast (2014-2027) 5-16-2013.xlsx , worktab = Bud. Adj., some of the cells around AD23 refer to the files Wilson RUS Loan Application Scenario V2.xlsx, or Coleman RUS Loan Application Scenario V2.xlsx, which do not appear to have been provided. Please provide those files electronically, and any other files referenced by those. If there are any other workpapers, memos, reports, emails etc. concerning how the data in those files were developed, please provide that information electronically, with all formula intact.***

Response) Please see the attached CONFIDENTIAL electronic files entitled "*Wilson RUS Loan Application Scenario V2.xlsx*" and "*Coleman RUS Loan Application Scenario V2.xlsx.*"

Witness) Christopher A. Warren

Electronic Attachment(s) Produced Separately

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Item 18) ***In the file = Financial Forecast (2014-2026) 8-15-2013 (capacity market 50%).xlsx, worktab = Bud. Adj, the cells around AD23 are either pasted in or refer to files that have not been provided such as Coleman Scenario V2.xlsx. Please provide those files electronically, and any other files referenced by those. If there are any other workpapers, memos, reports, emails etc. concerning how the data in those files were developed, please provide that information electronically, with all formula intact.***

Response) Please see the attached CONFIDENTIAL electronic files entitled "*Wilson Scenario V2.xlsx*" and "*Coleman Scenario V2.xlsx*."

Witness) Christopher A. Warren

Electronic Attachment(s) Produced Separately

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2013-00199

Response to the Kentucky Industrial Utility Customers, Inc.'s
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dated September 16, 2013

September 30, 2013

Item 19) ***In the file = Financial Forecast (2014-2017) 5-16-2013 (Filed Confidential).xlsx, worktab = Bud. Adj contains no values. What is the implication of this tab having no values, versus the other Financial Forecast models having values in the Bud. Adj worktab? Please provide a detailed explanation.***

Response) Please reference the attachment in Big Rivers' response to AG 1-155 (page 4 of 9) for a description of the Bud. Adj. worksheet.

Witness) Christopher A. Warren

BIG RIVERS ELECTRIC CORPORATION

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Item 20) ***The financial forecast file - "Financial Forecast (2014-2027) 5-16-2013.xlsx" contains references to files that were not supplied, though the same files may have been supplied, but with different names. It appears there are 17 files referenced from the financial model, which are identified in a screen print found below. Please provide these files, or if they already have been provided with different names, then please provide a translation between the 17 file names and the file names of the files that were provided already in Big Rivers' confidential data responses.***

Source	Type
2013-16 Capital Plan (Alcan RC) 4-12-2013.xlsx	Worksheet
2013-2014 Depreciation-New Rates-Net Value (Alcan RC) with CWIP.xlsx	Worksheet
2014 ALCAN.xlsx	Worksheet
2014-2016 Forecast Support (Debt Work Paper - 2013 03).xlsm	Worksheet
2015 ALCAN.xlsx	Worksheet
2015-2016 Depreciation-New Rates-Net Value (Alcan RC) with CWIP.xlsx	Worksheet
2016 ALCAN.xlsx	Worksheet
Big Rivers PCM Run 4-22-13 (2013-2027).xlsx	Worksheet
CFC 2012 Term Equity Loans and Investments in CTCs.xlsx	Worksheet
CoBank, CFC, and Series A Note (rev 07-27-12).xlsx	Worksheet
Coleman RUS Loan Application Scenario V2.xlsx	Worksheet
Debt (PCB and RUS B) July 2011.xlsx	Worksheet
Debt Work Paper - 2012 09.xlsx	Worksheet
Demand Energy Budget 2013-2017 for Alcan Rate Case-2013-04-18.xlsx	Worksheet
Demand Energy Budget 2018 thru 2026.xlsx	Worksheet
Financial Forecast (3 + 9) 05-7-13.xlsx	Worksheet
Wilson RUS Loan Application Scenario V2.xlsx	Worksheet

Response) The file "2013-16 Capital Plan (Alcan RC) 4-12-2013.xlsx" was provided in response to PSC 1-57 and was labeled "2013-16 Capital Plan (Alcan RC).xlsx."

The file "2013-2014 Depreciation-New Rates-Net Value (Alcan RC) with CWIP.xlsx" was provided in response to PSC 1-57 and was labeled "2013-2014 Depreciation.xlsx."

The files "2014 Alcan" and "2015 Alcan" were provided in response to PSC 1-57.

The file "2016 Alcan" was provided in response to AG 1-227.

The file "2014-2016 Forecast Support (Debt Work Paper - 2013 03).xlsm" was provided in response to PSC 1-57 and was labeled "Debt Work Paper – 2013.xlsm."

The file "2015-2016 Depreciation-New Rates-Net Value (Alcan RC) with CWIP.xlsx" was provided in response to PSC 1-57 and was labeled "2015-2016 Depreciation.xlsx."

The file "Big Rivers PCM Run 4-22-13 (2013-2027).xlsx" was provided in response to PSC 1-57 and was labeled "Big Rivers PCM Run 4-22-13 (Filed Confidential).xlsx."

The file "CFC 2012 Term Equity Loans and Investments in CTCs.xlsx" was provided in response to PSC 1-57 and was labeled "CFC 2012."

The file "CoBank, CFC, and Series A Note (rev 07-27-12).xlsx" was provided in response to PSC 1-57 and was labeled "CoBank, CFC, and Series A Note.xlsx."

The files "Coleman RUS Loan Application Scenario V2.xlsx" and "Wilson RUS Loan Application Scenario V2.xlsx" were provided in response to KIUC 2-17.

The file "Debt (PCB and RUS B) July 2011.xlsx" was provided in response to PSC 1-57 and was labeled "Debt (PCB and RUS B).xlsx."

The file "Debt Work Paper – 2012 09.xlsx" was provided in response to PSC 1-57 and was labeled "Debt Work Paper – 2012.xlsx."

The file "Demand Energy Budget 2013-2017 for Alcan Rate Case-2013-04-18.xlsx" was provided in response to PSC 1-57 and was labeled "Demand Energy Budget 2013-2017.xlsx."

The file "Demand Energy Budget 2018 thru 2026.xlsx" is provided as an attachment to this response.

The CONFIDENTIAL file "Financial Forecast (3 + 9) 05-7-13.xlsx" is provided as an attachment to this response and submitted under a petition for confidential treatment.

Witness) Christopher A. Warren

Electronic Attachment(s) Produced Separately

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Item 21) ***It appears that the source of the capital expenditures for the financial models is the spreadsheet "2013-16 Capital Plan (Alcan RC).xlsx". However, the capital expenditures in that spreadsheet do not extend out beyond 2016. It also appears that costs in the financial model that are beyond 2016 are derived by escalating prior year values at an inflation rate. Please explain why this approach has been used as opposed to developing long-term forecasts for capital expenditures.***

Response) The spreadsheet "2013-16 Capital Plan (Alcan RC).xlsx" reflects Big Rivers' forecasted capital expenditures through 2016. For capital expenditures beyond 2016, Big Rivers applied the standard approach for developing longer-term forecasts: deriving capital expenses by escalating prior year values at an inflation rate. In circumstances where Big Rivers forecasted an event expected to drive capital to be higher or lower than the normal escalation rate, Big Rivers added or subtracted capital dollars in the financial model to account for that event.

Witness) Christopher A. Warren

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Item 22) ***Please explain why no Baseline capital costs have been included for Wilson and Coleman after the units are brought back into service. If that was an oversight, please provide the annual values that should be included. Please state whether the Company is aware of any other costs for Wilson or Coleman that have not been included in the Company's analysis, and provide an annual schedule of those costs by cost category.***

Response) The baseline capital costs that have been included for Wilson and Coleman after the units are brought back into service can be located on the Bud. Adj. worksheet of the financial model, rows 29 and 37. Big Rivers is not aware of any costs for Wilson or Coleman that have not been included in its analysis.

Witness) Christopher A. Warren

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Item 23) ***In the spreadsheet - 2013-16 Capital Plan (Alcan RC).xlsx, two categories of HAPS/MATS costs appear, HAPS/MATS - Capitalized Interest, and HAPS/MATS Project. Please discuss what these relate to, and provide a schedule breaking these costs down to the specific project being performed, and the unit where the project is being performed.***

Response) The category 'HAPS/MATS – Capitalized Interest' is simply the capitalized interest for the HAPS/MATS project. Big Rivers capitalizes interest expense on capital projects greater than $250,000. The remainder of capitalized interest is budgeted in the Transmission section of budget, located in the file entitled "2013-16 Capital Plan (Alcan RC).xlsx".

The category HAPS/MATS Project refers to projected capital expenditures for the MATS work. This work includes foundations, silos, blowers, piping, electrical and controls for both DSI (dry sorbent injection) and ACI (Activated Carbon Injection) systems. For 2014, this work is broken down as follows:

Green	$[redacted]
Wilson	$[redacted]
Coleman	$[redacted]

In addition, there is a third line item that represents $[redacted] for monitors at HMP&L Station Two.

The file "2013-16 Capital Plan (Alcan RC).xls" was submitted with Big Rivers' response to PSC 1-57. At the time Big Rivers filed its Application it fully intended to proceed with installation of all MATS equipment as approved by the Commission in Case No. 2012-00063. Big Rivers' management currently believes it is prudent to defer MATS expenditures at the Coleman and Wilson plants until closer to the time they will return to service, thus the capital budget associated with the Coleman and Wilson MATS compliance will be less than what has been filed in this case.

Witness) Robert W. Berry

BIG RIVERS ELECTRIC CORPORATION

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Item 24) ***The tab, ECP, in the financial model has a pasted in value in cell F14. Please provide a detailed breakdown of what makes up that cost, and provide an explanation of how that value is used in the financial model analysis.***

Response) The value in cell F14 on the ECP worksheet in the financial model represents the projected spending in 2013 for the Environmental Compliance Plan at the time this case was filed. The detail for MATS compliance in the Environmental Compliance Plan was provided as projects 8-11 in Exhibit Berry-2 for Case No. 2012-00063. This amount combined with the forecasted spending for 2014 makes up the total amount for the project to be placed in service. For the current assumptions for the MATS project, please refer to KIUC 2-23.

Witness) Christopher A. Warren

BIG RIVERS ELECTRIC CORPORATION

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Item 25) ***Please provide a similar table to what was provided in response to KIUC 1-67, but provide the savings for each year through 2019, at which time both units will be brought back on line. Please provide this electronically with all formulas intact.***

Response) The table in Big Rivers' response to KIUC 1-67 provided the 2014 – 2015 average annual fixed cost savings for Wilson and Coleman Stations comparing the stations running versus the stations idled. Please see the attached CONFIDENTIAL electronic table displaying the annual fixed cost savings for the 2014 – 2016 time period. Big Rivers does not have this comparison past 2016 as it does not have the forecasted costs compared to budgeted, i.e. if the station is budgeted to be idled, there is no cost forecasted for the station running after 2016 and vice versa. The annual fixed cost savings will be slightly different depending on what maintenance is planned for that year so the average annual savings are a good indicator to utilize for planning purposes.

Witness) Robert W. Berry

Electronic Attachment(s) Produced Separately

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Item 26) ***Please provide a similar table to what was provided in response to KIUC 1-29, but provide the information for the entire period of 2013 through 2027. It is sufficient to provide the information on an annual basis and just for the Coleman and Wilson plants. Please provide this information electronically with all formula intact.***

Response) Big Rivers objects to this request on the grounds that it is overly broad and unduly burdensome. Notwithstanding these objections, but without waiving them, please see the attached CONFIDENTIAL electronic file for a table similar to what was provided in Big Rivers' response to KIUC 1-29 for the period 2013 - 2016. The information is provided on an annual basis just for the Coleman and Wilson plants. Big Rivers does not have an approved capital expenditure plan beyond 2016. The current Wilson Station 2013-2016 capital plan was developed in 2012 with much uncertainty surrounding the timing of the unit lay-up and restoration. The 2014-2017 Wilson Station capital plan that will be presented to the Big Rivers Board for approval in November 2013 will include only layup related expenditures for 2014, and will not include any capital dollars for Wilson Station in 2015 or 2016.

Witness) Robert W. Berry

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Item 27) ***The Company's response KIUC 1-53 contain historic fixed and variable O&M values for Coleman and Wilson. Please identify the originating spreadsheet, worktab and cell where the fixed and variable O&M costs for Coleman and Wilson are loaded into (for the 2014 - 2027 case) that ultimately flow to the Financial Model. Also, identify which line or lines in the worktab - Stmts RUS of the financial model - Financial Forecast (2014-2027) 5-16-2013.xlsx, the Coleman and Wilson fixed and variable O&M are included in.***

Response) Fuel and reagent expenses are loaded into the financial model on the PCM worksheet in rows 21, 23-25, 40, 43-45, 52, 54-56 and 121-135. The fixed expenses included for Coleman and Wilson are provided from the budget department in the Hyperion output files "2014 Alcan.xlsx", "2015 Alcan.xlsx" and "2016 Alcan.xlsx." The expenses for Coleman and Wilson are loaded into the financial model on the O&M worksheet in rows 127-139 and 149-160.

These expenses are included on rows 92, 93 and 104 of the Stmts RUS worksheet.

Witness) Christopher A. Warren

BIG RIVERS ELECTRIC CORPORATION

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Item 28) ***With regard to the Wilson Plant Costs found in the response to KIUC 1-21 (Rows 1-9), and the financial forecasts model - Financial Forecast (2014-2027) 5-16-2013.xlsx, please provide the following for all the values contained in the table from KIUC 1-21:***

a. ***The cell reference (file, tab, row, column) of where the exact values can be found in the financial model or in the associated model spreadsheets.***

b. ***If the values are not incorporated directly into the financial model or the associated model spreadsheets, please explain why not.***

c. ***If the values are incorporated in an indirect way, please explain how they have been incorporated.***

d. ***If the values are embedded in an item used in the financial model or associated model spreadsheets, please provide that cost value, the other values comprising this value, and the cell reference of that value in the financial model or linked spreadsheet.***

Response:

a. The exact values of Wilson Plant Costs found in Big Rivers' response to KIUC 1-21 (Rows 1-9) cannot be found directly in the financial model. Please see the attachment to KIUC 1-21, labeled 'Property Insurance

Calculation' for the calculated monthly amounts of property insurance for the Wilson plant.

b. All costs found in Big Rivers' response to KIUC 1-21 are linked by account into the financial forecast model, not by individual plant or department. The source files are the Hyperion budget files, and were provided in Big Rivers' responses to PSC 1-57 and AG 1-227. Please see files '2014 ALCAN' and '2015 ALCAN' that were included in Big Rivers' response to PSC 1-57, and '2016 ALCAN' that was provided in Big Rivers' response to AG 1-227, and view the worksheets 'LABOR', 'PROP INS', 'PROP TAX', 'DEPR', 'OTHER' and 'PROD NL'.

c. Please see Big Rivers' response to subpart (b) above.

d. Please see Big Rivers' response to subpart (b) above. Please note that the costs are included in worksheets 'O&M', 'Capex & Depr' and 'Debt' in the 'Financial Forecast (2014-2027) 5-16-2013.xlsx' file distributed by account number as shown in the Hyperion budget files mentioned in (b) above. For property insurance, view the 'O&M' worksheet, lines 70-79. For property tax, view the 'O&M' worksheet, lines 84-96. For production non-labor (or fixed departmental expense), view the 'O&M' worksheet, lines 127-145. For labor, view the 'O&M' worksheet, lines 149-181. For depreciation, view the

'Capex & Depr' worksheet, lines 37-38. For interest expense, view the 'Debt' worksheet, lines 105-109.

Witness) Jeffrey R. Williams

BIG RIVERS ELECTRIC CORPORATION

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Item 29) ***With regard to the Coleman Plant costs found in the response to KIUC 1-22 (Rows 1-9), please provide the same information as requested in the prior question.***

Response:

a. The exact values of Coleman Plant Costs found in Big Rivers' response to KIUC 1-22 (Rows 1-9) cannot be found directly in the financial model. Please see the attachment to KIUC 1-21, labeled 'Property Insurance Calculation' for the calculated monthly amounts of property insurance for the Coleman plant.

b. All costs found in Big Rivers' response to KIUC 1-22 are linked by account into the financial forecast model, not by individual plant or department. The source files are the Hyperion budget files, and were provided in response to PSC 1-57 and AG 1-227. Please see files '2014 ALCAN', '2015 ALCAN' that were included in Big Rivers' response to PSC 1-57, and '2016 ALCAN' that was provided in Big Rivers' response to AG 1-227, and view the worksheets 'LABOR', 'PROP INS', 'PROP TAX', 'DEPR', 'OTHER' and 'PROD NL'.

c. Please see Big Rivers' response to subpart (b) above.

d. Please see Big Rivers' response to subpart (b) above. Please note that the costs are included in worksheets 'O&M' , 'Capex & Depr' and 'Debt' in the 'Financial Forecast (2014-2027) 5-16-2013.xlsx' file distributed by account number as shown in the Hyperion budget files mentioned in (b) above. For property insurance, view the 'O&M' worksheet, lines 70-79. For property tax, view the 'O&M' worksheet, lines 84-96. For production non-labor (or fixed departmental expense), view the 'O&M' worksheet, lines 127-145. For labor, view the 'O&M' worksheet, lines 149-181. For depreciation, view the 'Capex & Depr' worksheet, lines 37-38. For interest expense, view the 'Debt' worksheet, lines 105-109.

Witness) Jeffrey R. Williams

BIG RIVERS ELECTRIC CORPORATION

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Item 30) ***Refer to the Company's response to KIUC 1-2(b). Please provide the calculation of the 1846.5 mW of capacity that was sought in this request, but was not provided in the response.***

Response) Big Rivers objects to this request on the grounds that Big Rivers has previously provided all information and documents necessary for the intervenor to determine the response without further input. Notwithstanding this objection, but without waiving it, Big Rivers states that MISO's calculation is [effective ICAP]-([effective ICAP]*[XEFORd]), as shown in the attachment to Big Rivers' response to KIUC 1-2(b).

Witness) Robert W. Berry

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Item 31) ***Refer to the Company's response to KIUC 1-2(i). Please provide the calculations of the reserve margins for the load forecast period that were sought in this request, but were not provided in the response.***

Response) As previously stated, in Big Rivers' response to KIUC 1-2(i), the requested table does not exist and as such the calculations requested in this data request do not exist.

Witness) Robert W. Berry

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Item 32) ***Refer to the Company's response to KIUC 1-48 in which it provides the assumptions used for "replacement load" starting in 2016 at 100 mW, additional annual increments of 100 mW from 2017 through 2019 and then additional annual increments of 200 mW from 2020 through 2021. Please provide all support for these load growth assumptions, including all underlying assumptions, such as the composition and sources of the additional load, the pricing discounts necessary to entice and obtain each of these loads, if any, and whether each of these loads is new load due to a new facility or load transferred from and presently served by another utility or supplier.***

Response) Big Rivers objects to this request on the grounds that it is overly broad and unduly burdensome. Notwithstanding these objections, but without waiving them, Big Rivers states that the replacement load forecasted in Big Rivers' long-term load forecast was determined based on informed judgment. Big Rivers forecasted replacement load assuming the replacement load could take many forms. Please see Big Rivers' response to PSC 2-16 for a detailed discussion of the various replacement load efforts undertaken by Big Rivers in determining Big Rivers' replacement load forecast. The replacement load was not meant to be specific, but rather represented what Big Rivers' management believed was a reasonable expectation for load replacement given all of the information available to it at the time. The

replacement load was assumed to have a 75% load factor because Big Rivers believed it was likely to be composed of a combination of rural, large industrial, and market transactions.

Witness) Lindsay N. Barron

BIG RIVERS ELECTRIC CORPORATION

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Item 33) ***Refer to page 3 lines 2-3 of the Company's response to KIUC 1-51 wherein Mr. Berry states that "It just does not make sense for Big Rivers to retire these plants and deprive Members of the future benefits these plants will provide." Please provide a copy of all economic studies performed by the Company to demonstrate and quantify that there are "future benefits" on a net present value basis.***

Response) Big Rivers has not performed net present value analyses on the plants; however, there have been a number of production cost models and financial models presented in this case that demonstrate that these plants will add value to Big Rivers' Members in the future. Most recently, the sensitivity analysis which factors in the value of capacity revenues to Big Rivers' Members, as projected by Wood Mackenzie, demonstrates significant future benefits provided by the plants to Big Rivers' Members.

Witness) Robert W. Berry

BIG RIVERS ELECTRIC CORPORATION

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Item 34) ***Refer to the Company's response to KIUC 1-58. Please provide all support for the assumption of a 2% TVA rate increase.***

Response) In 2009, the cost of TVA transmission was $201,700 monthly. In 2013, the cost was $220,100 monthly. The compound annual growth rate (CAGR) for the four year period was 2.21%. Because Big Rivers actually experienced this increase over the last four years, it was assumed to be reasonable for projecting future increases. A copy of the 2009 and 2013 invoice is attached for reference.

Witness) Robert W. Berry

V# 4560
PO 02/02/09
WR# 007695
WR date 02/02/09

TVA

543971

Transmission Service Invoice

BIG RIVERS ELECTRIC CORPORATION
M. DEE MCDOWELL, CPA
201 THIRD STREET
HENDERSON, KY 42420

Invoice Number: E09-01-5051-P
Service for Period Ending: 12/31/2008
Invoice Date: 01/13/2009
Payment Due Date: 02/02/2009

	Quantity (MWh)	Rate	Amount
Contract: 00016433			
FIRM			
TRANSMISSION			
YEARLY	100	$1,617.000	$161,700.00
TOTAL			**$161,700.00**
SCHEDULING, SYSTEM CONTROL, AND DISPATCH			
YEARLY	100	$175.000	$17,500.00
TOTAL			**$17,500.00**
REACTIVE CONTROL AND VOLTAGE SUPPORT SERVICE			
YEARLY	100	$225.000	$22,500.00
TOTAL			**$22,500.00**
TOTAL FIRM			**$201,700.00**
Contract: TV-99904V			
NON FIRM			
TRANSMISSION			
HOURLY	350	$2.920	$1,022.00
TOTAL			**$1,022.00**
SCHEDULING, SYSTEM CONTROL, AND DISPATCH			
HOURLY	350	$0.240	$110.00
TOTAL			**$110.00**
REACTIVE CONTROL AND VOLTAGE SUPPORT SERVICE			
HOURLY	350	$0.310	$142.50
TOTAL			**$142.50**
TOTAL NON FIRM			**$1,274.50**
TOTAL CHARGES			**$202,974.50**

256017 565.100 202,974.50

MDM-1-13-09
BJ 1-13-09

Late charges will be assessed if payment is not received by the due date.

Big Rivers Electric Corporation
Case No. 2013-00199

Wire #: 52133
ck date: 2/5/13

Attachment for Response to KIUC 2-34

Transmission Service Invoice

BIG RIVERS ELECTRIC CORPORATION
M. DEE MCDOWELL, CPA
201 THIRD STREET
HENDERSON, KY 42420

Invoice Number:	E13-01-5051-P
Service for Period Ending:	12/31/2012
Invoice Date:	01/16/2013
Payment Due Date:	02/05/2013

	Quantity (MWh)	Rate	Amount
Contract: 00016433			
FIRM			
TRANSMISSION			
YEARLY	100	$1,741.000	$174,100.00
TOTAL			**$174,100.00**
SCHEDULING, SYSTEM CONTROL, AND DISPATCH			
YEARLY	100	$180.000	$18,000.00
TOTAL			**$18,000.00**
REACTIVE CONTROL AND VOLTAGE SUPPORT SERVICE			
YEARLY	100	$280.000	$28,000.00
TOTAL			**$28,000.00**
TOTAL FIRM			**$220,100.00**
TOTAL CHARGES			**$220,100.00**

Late charges will be assessed if payment is not received by the due date.

Make remittance to:

TENNESSEE VALLEY AUTHORITY
P.O. BOX 1000
DEPT. 87
MEMPHIS, TN 38148-0087

ACH Credit Payment Instructions:

ABA# 051036706; Account# [redacted]
Please include addenda record listing invoice number.
Note: Fedwire instructions are different from above.
Contact (865) 632- 4410 or 7143
For Billing inquiries contact (865) 632-2690

Emb 01-18-13

YP 1/18/13

BRSTMOPS
565100-0000
0801
0999

 A/P Rcvd 1/18/13

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Item 35) *Refer to the file Demand Energy Budget 2013-2017.xlsx.*

a. *Please indicate if the Company's BOD approved this Demand Energy Budget 2013-2017, and if so, for what purpose(s) it was approved. If so, then please provide all documents that were provided to the BOD prior to its approval, including all support for the projected new load and related assumptions, and a copy of all documentation of the BOD's approval of this Demand Energy Budget.*

b. *Please identify each of the projected new loads that will commence taking service on January 1, 2016. Describe the status of each such new load and the terms used to attract the new load, e.g., discounted tariff rates, fixed price contracts, etc.*

c. *Please identify each of the projected new loads that will commence taking service on January 1, 2017. Describe the status of each such new load and the terms used to attract the new load, e.g., discounted tariff rates, fixed price contracts, etc.*

d. *Please provide a copy of all analyses prepared by, available to Big Rivers through its various economic development affiliations/memberships, and/or otherwise relied on by Big Rivers to assess the lead time necessary for a new*

Large Industrial load to locate and develop a new site and production facility.

e. *Please provide the source of the "Projected New Load MW" line item (line 38). Provide all analyses in support of and underlying this projection.*

f. *Please provide the source of the load factor that was used to derive the "Projected New Load MWh" line item (line 74). Provide all analyses in support of and underlying this assumption.*

g. *Please separate the new load into Rural Residential, Rural Commercial, and Large Industrial for each month 2016-2017.*

h. *Please identify, describe, and provide a copy of all programs adopted or that the Company plans to adopt to increase its Rural Residential load by 2016 for purposes of the "Projected New Load."*

i. *Please identify, describe, and provide a copy of all programs adopted or that the Company plans to adopt to increase its Rural Commercial load by 2016 for purposes of the "Projected New Load."*

j. *Please identify, describe, and provide a copy of all programs adopted or that the Company plans to adopt to increase its Large Industrial load by 2016 for purposes of the "Projected New Load."*

Response)

a. The referenced Demand and Energy file is an input to the overall Big Rivers corporate budget that is approved by the Board of Directors. Please see the attachment to Big Rivers' response to PSC 2-19 for the presentation given to the Board related to the budget. Please also see page 864 of the CONFIDENTIAL attachment to Big Rivers' response to AG 1-38 in Case No. 2012-00535 for documentation of the Board's approval of the budget.

b. Please see Big Rivers' response to KIUC 2-32.

c. Please see Big Rivers' response to KIUC 2-32.

d. There are no such analyses; however, based on past experience, Big Rivers is aware that there is a significant lead time for new large industrial load site development.

e. Please see Big Rivers' response to KIUC 2-32.

f. Please see Big Rivers' response to KIUC 2-32.

g. Please see Big Rivers' response to KIUC 2-32.

h. No specific programs have been adopted by the company for these purposes.

i. Big Rivers' members (Kenergy Corp., Jackson Purchase Energy Corporation, and Meade County Rural Electric Cooperative Corporation (collectively, the "Members")) continue to aggressively seek new commercial and industrial loads within their territory. Each Member has resources dedicated to this task. The Members' staffs actively work with local, regional and state economic development officials to identify and provide technical planning support and electricity pricing quotes to interested economic development prospects. Big Rivers' staff supports the Members' economic development efforts by attending economic development visits at the request of its Members while providing timely transmission infrastructure cost projections and energy rate pricing estimates given the specific load parameters of the prospect. Big Rivers and the Members have recently joined Kentucky United, which is a collaborative partnership to market and promote economic development within Kentucky. Kentucky United works alongside the Kentucky Cabinet for Economic Development and other economic development professionals from across the state to proactively attract and recruit new industry to the Commonwealth.

j. See Big Rivers' response to subpart (i) above.

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2013-00199

Response to the Kentucky Industrial Utility Customers, Inc.'s
Second Request for Information
dated September 16, 2013

September 30, 2013

1

2 **Witness)** Lindsay N. Barron

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2013-00199

Response to the Kentucky Industrial Utility Customers, Inc.'s
Second Request for Information
dated September 16, 2013

September 30, 2013

Item 36) *Refer to the Company's response to PSC 2-16.*

a. Has the Company offered discounts off the tariffed rates that it proposes in this proceeding to attract any of the potential customer loads? If so, please provide this additional detail for each such transaction identified in response to PSC 2-16.

b. If the Company has offered discounts off the tariffed rates that it proposes in this proceeding, then please provide all principles relied on for this purpose and the quantitative basis for each such discount. Also provide all documentation of these principles and their application to the specific transactions set forth in the response to PSC 2-16.

c. Does the Company plan to offer discounts off the tariffed rates that it proposes in this proceeding to attract any of the potential customer loads?

d. Is the Company agreeable in principle to discounting the tariffed rates that it proposes in this proceeding to attract potential customer loads? If so, then provide all principles the Company will apply for such discounts and describe how it plans to determine and quantify the discount for a potential customer load.

e. ***If the Company has offered or is willing to offer discounts off the tariffed rates that it proposes in this proceeding, identify the officers who approved these discounts and indicate if the Company's BOD approved these discounts. Provide all documentation.***

f. ***Is it the Company's position that it can discount tariffed rates without approval by the Commission? If the Company's position is that it must obtain the Commission's approval to discount tariffed rates, does the Company plan to do so, and if so, when does it plan to do so?***

g. ***Is the Company aware of any other cooperative or other supplier that has successfully acquired customer loads that previously were supplied by TVA?***

Response)

a. Big Rivers has made a number of proposals to counterparties, some of which were market-based products and others of which were tariff-based products. Many of the proposals combined fixed demand charges with tariff-based energy charges. Big Rivers has proposed an economic development incentive rate in a number of its proposals. The economic development incentive rate

contemplated by Big Rivers includes a fixed demand component of $[redacted] with energy charges and riders charged at [redacted].

b. Big Rivers relied on the principles outlined in an order by the Kentucky Public Service Commission in Administrative Case No. 327 (September 24, 1990), which is attached hereto for reference.

c. Yes.

d. Yes, please see Big Rivers' response to subpart (b) above.

e. Big Rivers' CEO and COO have authorized the proposal of economic development rates to potential counterparties; however, any retail agreements that deviate from tariffed rates will require approval by Big Rivers' board of directors, RUS, and the PSC prior to execution.

f. Big Rivers' position is that economic development rates offered to encourage new or expanded large industrial load should be implemented by special contract between and among Big Rivers, its respective distribution cooperative, and the large industrial customer. Any such contract would be submitted to the Commission for review in accordance with the principles established by the Commission in Administrative Case No. 327.

g. Big Rivers is not currently aware of loads that were previously supplied by TVA that have been successfully acquired by others; however, Big Rivers has not historically monitored TVA customer base changes.

Witness) Robert W. Berry

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN INVESTIGATION INTO THE IMPLEMENTATION OF ECONOMIC DEVELOPMENT RATES BY ELECTRIC AND GAS UTILITIES	)))	ADMINISTRATIVE CASE NO. 327

O R D E R

On February 10, 1989, the Commission initiated this proceeding to examine its guidelines regarding economic development rates and to seek comments and recommendations from the major gas and electric utilities in the state on the use of these special rates. For the purposes of this investigation, an economic development rate ("EDR") is considered to be a gas or electric rate discount, offered to large commercial and industrial customers, which is intended to stimulate the creation of new jobs and capital investment both by encouraging existing customers to expand their operations and by improving the likelihood that new large commercial and industrial customers will locate in Kentucky.

The Commission's EDR guidelines were outlined in its July 1, 1988 Order in Case No. 10064[1]. As stated in that Order, any utility wishing to offer economic development rates to specific customers should satisfy the following six guidelines:[2]

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1 Case No. 10064, Adjustment of Gas and Electric Rates of Louisville Gas and Electric Company.

2 Case No. 10064, Order dated July 1, 1988, pages 93-94.

1. Each utility should be required to provide an affirmative declaration and evidence to demonstrate that it has adequate capacity to meet anticipated load growth each year in which an incentive tariff is in effect.

2. Each utility should be required to demonstrate that all variable costs associated with the transaction during each year that the contract is in effect will be recovered and that the transaction makes some contribution to fixed costs. Furthermore, the customer-specific fixed costs associated with adding an economic development/incentive customer should be recovered either up front or as a part of the minimum bill over the life of the contract.

3. Each utility that offers an economic development rate should be required to document and report any increase in employment and capital investment resulting from the tariff and contract. These reports should be filed on an annual basis with the Commission.

4. Each utility that intends to offer economic incentive rates should be required to file a tariff stating the terms and conditions of its offering. Furthermore, each utility should be required to enter into a contract with each customer which specifies the minimum bill, estimated annual load, and length of contracting period. No contract should exceed 5 years. All contracts shall be subject to the review and approval of the Commission.

5. Each utility should be required to include a clause in its contract that states that the tariff will be withdrawn when the utility no longer has adequate reserve to meet anticipated load growth.

6. Each utility should be required to demonstrate that rate classes that are not party to the transaction should be no worse off than if the transaction had not occurred. Under special circumstances, the Commission will consider utility proposals for contracts that share risk between utility shareholders and other ratepayers. However, if a utility proposes to charge the general body of ratepayers for the revenue deficiency resulting from the EDR through a risk-sharing mechanism then the utility will be required to demonstrate that these ratepayers should benefit in both the short- and long-run. In addition, at least one-half of the deficiency will be absorbed by the stockholders of the utility and will not be passed on to the

> general body of ratepayers. The amount of the deficiency will be determined in future rate cases by multiplying at least one-half of the billing units of the EDR contract(s) by the tariffed rate that would have been applied to customer(s) if the EDR contract(s) had not been in effect.

The following gas and electric utilities were made parties to this proceeding: Louisville Gas and Electric Company ("LG&E"); Kentucky Power Company ("KPC"); Kentucky Utilities Company ("KU"); The Union Light, Heat and Power Company ("ULH&P"); Big Rivers Electric Corporation ("Big Rivers"); East Kentucky Power Cooperative, Inc. ("EKPC"); Columbia Gas of Kentucky, Inc. ("Columbia"); Delta Natural Gas Company, Inc. ("Delta"); and Western Kentucky Gas Company ("Western"); collectively ("participating utilities"). In addition, the following parties sought and were granted intervention status: the Office of the Attorney General ("AG"); Green River Electric Corporation ("Green River"); Henderson-Union Rural Electric Cooperative Corporation ("Henderson-Union"); and the Kentucky Cabinet for Economic Development ("Cabinet").

In its February 10, 1989 Order in this case, the Commission posed several questions pertaining to the feasibility, design and implementation of EDRs. The responses filed by the participating utilities and testimony filed by the Cabinet greatly assisted the Commission in its consideration of effective EDR guidelines. In addition, testimony provided at a hearing conducted on June 22, 1989, and post-hearing briefs filed by several parties further elucidated some of the important issues related to EDRs. The primary issues to be addressed by the Commission in this Order are

adequate capacity requirements, variable cost recovery, customer-specific fixed cost recovery, job creation and capital investment criteria, implementation of EDRs, risk allocation, load eligibility, retention rates, waivers of gas main extension costs, and the appropriate term of EDR contracts. Finally, the Commission will address a Cabinet proposal that it be allowed to file comments pertaining to utilities' EDR contracts.

ADEQUATE CAPACITY REQUIREMENT

The capacity requirements contained in Guidelines 1 and 5 are based on two premises. First, additional load resulting from discounted rates should not create a need for new plant capacity. Second, during periods of excess capacity, the load resulting from EDRs increases a utility's operating efficiency and allows sales of capacity that may not have occurred without the EDRs. Any capacity in excess of a reserve margin normally considered adequate to ensure system reliability could be used to provide service under EDRs without unduly hastening the need for new capacity.

Several participating utilities contend that specific capacity requirements should not be imposed on utilities offering EDRs. Columbia and Delta assert that adequate capacity availability is a responsibility of the utility and should not be a specific requirement of an EDR.[3] EKPC contends that, as long as EDRs exceed marginal costs, EDRs should be offered, even if a

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3 Columbia's Response to the Commission's Order dated February 10, 1989, Item 11; Delta's Response to the Commission's Order dated February 10, 1989, Item 11.

utility must add capacity to serve the load.[4] Similarly, KPC states that economic growth should not be capped by a desire to avoid electric capacity additions.[5]

LG&E, on the other hand, contends that without an adequate capacity requirement, new capacity additions could be required to serve a load that is not sharing fully in the fixed cost associated with the capacity addition.[6] Big Rivers states that a utility should demonstrate that adequate capacity is available to serve EDR customers unless the utility can show that any additional capacity needed to serve the new load would not increase its cost of service.[7] Western states that the availability of EDRs should be contingent on a demonstration of adequate capacity.[8]

The Commission finds that EDRs should only be offered during periods of excess capacity and that each utility should demonstrate, upon submission of each EDR contract, that the load expected to be served during each year of the contract period will not cause the utility to fall below a reserve margin that is considered essential for system reliability. Such a reserve

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4 EKPC's Response to the Commission's Order dated February 10, 1989, Item 11.

5 KPC's Response to the Commission's Order dated February 10, 1989, Item 11.

6 LG&E's Response to the Commission's Order dated February 10, 1989, Item 11.

7 Big Rivers' Response to the Commission's Order dated February 10, 1989, Item 11.

8 Western's Response to the Commission's Order dated February 10, 1989, Item 11.

margin should be identified and justified with each EDR contract filing.

Guideline 5 currently requires utilities to withdraw the EDR if adequate reserves are not available to meet anticipated load growth. There is a general feeling among the participating utilities that once the Commission approves an EDR contract for a customer it should not be withdrawn. Columbia maintains that the use of EDRs should be discontinued if adequate capacity is not available to serve new EDR load, however EDRs should not be withdrawn from customers to whom commitments have already been made.[9] Big Rivers states that, at the time an EDR contract is being considered, if the added load cannot be served without increasing system costs, a contractual commitment should not be made.[10] The Commission concludes that, while the load of EDR customers should not create a need for additional capacity, an EDR should not be withdrawn from a customer already under contract.

VARIABLE COST RECOVERY

Guideline 2 currently requires all EDRs to recover variable costs and make some contribution to system fixed costs. The requirement that EDRs exceed variable costs is essential to an effective EDR policy. Revenues received from EDRs that exceed variable costs contribute to a portion of the utility's fixed costs that otherwise would have been paid by nonparticipating

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9 Columbia's Response to the Commission's Order dated February 10, 1989, Item 11(b).

10 Big Rivers' Response to the Commission's Order dated February 10, 1989, Item 11(b).

ratepayers. This contribution results in lower costs for all ratepayers as utility fixed costs are spread over a larger total load.

The participating utilities agree that discounted rates should, in all instances, cover the variable costs associated with serving EDR customers. In addition, EKPC maintains that short-run marginal (variable) costs should include the marginal cost of capacity as well as the marginal cost of energy.[11] LG&E contends that EDRs should not only recover all customer and variable costs, but should also make a contribution to system fixed costs.[12] Western, Big Rivers, KPC and ULH&P assert that utilities should be required to demonstrate that the discounted rate recovers variable cost each time an EDR contract is submitted to the Commission for approval.[13] ULH&P also suggests that a follow-up analysis be performed after the EDR has been in place for at least one year. This analysis should use cost-of-service principles to compare scenarios with and without the EDR customer. Similarly, EKPC states that utilities should submit an annual report to the Commission showing revenues collected from each EDR customer as

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11 EKPC's Response to the Commission's Order dated February 10, 1989, Item 12, page 1 of 3.

12 LG&E's Response to the Commission's Order dated February 10, 1989, Item 12.

13 Western's Response to the Commission's Order dated February 10, 1989, Item 12(a); Big Rivers' Response to the Commission's Order dated February 10, 1989, Item 12(a); KPC's Response to the Commission's Order dated February 10, 1989, Item 12(a); ULH&P's Response to the Commission's Order dated February 10, 1989, Item 12(a).

well as the variable and customer-specific costs associated with serving each customer.[14]

The Commission finds that variable cost recovery is a fundamental requirement of EDRs. Therefore, each time an EDR contract is submitted for approval, utilities should demonstrate that the discounted rate exceeds the total short-run marginal (variable) costs associated with serving that customer for each year of the discount period. Short-run marginal costs will include both marginal capacity costs and marginal energy costs. Demonstration of marginal cost recovery should be accomplished through the use of a current marginal cost-of-service study. A current study is one conducted no more that one year prior to the date of the contract. Furthermore, utilities should submit an annual report to the Commission showing revenues received from each EDR customer and the marginal costs associated with serving each EDR customer. Finally, during rate proceedings, utilities with EDR customers should demonstrate through detailed cost-of-service analysis that nonparticipating ratepayers are not adversely affected by these EDR customers.

CUSTOMER-SPECIFIC FIXED COST RECOVERY

Guideline 2 requires that customer-specific fixed costs associated with serving an EDR customer be recovered either as an up-front payment or as part of a minimum bill over the life of the contract. The participating utilities were fairly evenly divided

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[14] EKPC's Response to the Commission's Order dated February 10, 1989, Item 12(a).

on this issue. Columbia, Western, and ULH&P contend that, although customer-specific fixed costs should, in most instances, be recovered from the EDR customer, the recovery mechanism should be developed on a case-by-case basis.[15] EKPC suggests that customer-specific fixed costs be recovered either by a lump-sum payment by the EDR customers or through annual or monthly payments amortized over the EDR period.[16] Big Rivers recommends recovery through a contribution in aid of construction, monthly facilities charge, termination charge, minimum billing demand, or a combination of these methods.[17]

Delta, KU, and LG&E, on the other hand, contend, for various reasons, that customer-specific fixed costs should not be recovered from EDR customers.[18] KU asserts that EDR-specific fixed costs should be assigned to the EDR class as a whole, not to individual customers within the class. LG&E proposes to handle the customer-specific fixed costs associated with EDR customers in a manner similar to its present handling of other customer-specific capital expenditures. LG&E currently provides

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15 Columbia's Response to the Commission's Order dated February 10, 1989, Item 13; Western's Response to the Commission's Order dated February 10, 1989, Item 13; ULH&P's Response to the Commission's Order dated February 10, 1989, Item 13.

16 EKPC's Response to the Commission's Order dated February 10, 1989, Item 13.

17 Big Rivers' Response to the Commission's Order dated February 10, 1989, Item 13.

18 Delta's Response to the Commission's Order dated February 10, 1989, Item 13; KU's Response to the Commission's Order dated February 10, 1989, Item 13; LG&E's Response to the Commission's Order dated February 10, 1989, Item 13.

capital expenditures in an amount up to three times the expected annual net revenues of a customer. The customer must then provide the balance.

The Commission finds that nonparticipating ratepayers should be protected from contributing to the customer-specific fixed costs associated with serving customers who will be receiving a rate discount. It is not unreasonable to require these customers to reimburse the utility for these capital expenditures over the term of an EDR contract. However, the Commission finds that utilities should have the flexibility to design particular mechanisms by which these customer-specific fixed costs are to be recovered. Therefore, all EDR contracts should include a provision allowing for the recovery of customer-specific fixed costs over the term of the contract.

JOB CREATION AND CAPITAL INVESTMENT CRITERIA

Increased economic activity is the major objective of EDRs. Two key indicators of economic activity are job creation and capital investment. EDRs are expected to promote growth in both of these areas. The issue to be addressed here is whether specific job creation and capital investment levels necessary to qualify for EDRs should be established by the Commission, or whether these levels should merely be monitored by the Commission in order to assess the impact of EDRs on economic activity in the state.

The Commission finds that, while job creation and increases in capital investment are the desired outcome of EDRs, requiring

specific levels of job creation and capital investment for EDR eligibility might, in some instances, impede rather than promote economic activity. For instance, such a requirement might prevent a customer from participating in an EDR program even if tangible economic benefits unrelated to job creation or capital investment would have been realized. Furthermore, specific job creation and capital investment levels would be arbitrary and would not recognize the needs and characteristics of individual service areas and of new and expanding customers.

Several participating utilities express similar concerns. EKPC states that while job creation and increased capital investment are expected results of an EDR, an explicit requirement for increases in these areas would not necessarily help an existing customer whose current investment in facilities and employees is underutilized.[19] KPC asserts that, if the Commission establishes a threshold level of jobs or capital investment necessary to qualify for an EDR, some desired new industry might be lost.[20] Columbia and Western both maintain that job creation and capital investment potential are secondary to the load characteristics of the potential EDR customer.[21]

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19 EKPC's Response to the Commission's Order dated February 10, 1989, Item 5.

20 KPC's Response to the Commission's Order dated February 10, 1989, Item 5.

21 Columbia's Response to the Commission's Order dated February 10, 1989, Item 5; Western's Response to the Commission's Order dated February 10, 1989, Item 5.

The Commission finds that a uniform job creation and capital investment requirement for each EDR contract is inappropriate. However, the Commission has determined that monitoring the job creation and capital investment performance of EDRs would provide it with important information with which to measure the effectiveness of its EDR program. Therefore, all utilities with active EDR contracts should file annual reports to the Commission providing information as shown in Appendix A, which is attached hereto and incorporated herein.

IMPLEMENTATION OF EDRs

An EDR can be implemented by either of two methods. First, a standard EDR tariff or rider, explicitly stating all rates, terms and conditions, is filed by a utility and made available to a general classification of customers. Second, a utility files a special contract with an individual customer, which stutes rates, terms and conditions applicable to that specific customer. Guideline 4 currently requires a utility to submit a general EDR tariff, as well as individual contracts with each EDR customer. This procedure was intended to ensure the uniformity of EDRs while identifying the unique usage characteristics of the EDR customers.

The participating utilities have expressed varying opinions regarding the methods by which EDRs should be implemented. Columbia and Western contend that utilities should have the flexibility to design EDRs to match their individual situations.[22]

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22 Columbia's Response to the Commission's Order dated February 10, 1989, Item 8; Western's Response to the Commission's Order dated February 10, 1989, Item 8.

Big Rivers, KPC, and ULH&P assert that EDRs should be negotiated and offered through special contracts.[23] KPC further states that special contracts would allow the greatest amount of freedom in identifying a customer's needs, while at the same time minimizing the needless revenue reduction that occurs when all new industrial load is granted an EDR concession. Similarly, ULH&P contends that circumstances to be encountered in implementing an EDR are too diverse in nature to be covered by a general tariff. The utility needs to be flexible in negotiating EDRs.

Conversely, EKPC feels that a general tariff would allow better coordination of the review process by the Commission.[24] LG&E contends that a general tariff would avoid a proliferation of individual contracts that could hamper consistent planning.[25] However, LG&E further states that special contracts may be warranted in cases involving extenuating circumstances (i.e. those instances when application of a tariff would be inequitable to the customer class or to the customer).

Initially, the Commission was concerned that implementing EDRs through special contracts would increase the likelihood of the discriminatory use of EDRs by utilities. Even if price discrimination is unintended, EDR contracts would give utilities

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23 Big River's Response to the Commission's Order dated February 10, 1989, Item 8; KPC's Response to the Commission's Order dated February 10, 1989, Item 8; ULH&P's Response to the Commission's Order dated February 10, 1989, Item 8.

24 EKPC's Response to the Commission's Order dated February 10, 1989, Item 8.

25 LG&E's Response to the Commission's Order dated February 10, 1989, Item 8.

the right to selectively choose the customers to whom discounted rates would be offered. This would be unfair to customers whose usage characteristics were similar to customers receiving EDRs through special contracts but for some reason were not offered an EDR by the utility.

On the other hand, however, the Commission realizes that customers do not require identical incentives in order to locate a new facility in a particular area or to expand existing operations. In fact, for some customers, utility rate incentives may not even be a factor in their locational or expansionary decision-making process. Customers who would have decided to locate in Kentucky or expand existing operations even in the absence of rate discounts, but who would take advantage of EDRs that are offered to all new or expanding customers, in effect, become "free riders" on the utility system at the expense of all other ratepayers.

Current Commission EDR guidelines require utilities to file a general EDR rate schedule. This requirement, in effect, fixes the rate discount that is offered to all EDR customers regardless of their individual needs or usage characteristics. This precludes utilities from determining the minimum discount necessary to provide an incentive to new and existing customers and to identify potential free riders who do not require a discounted rate.

The Commission concludes that the revenue loss resulting from free riders taking advantage of rate discounts offered through general EDR tariffs is detrimental to the utility and all nonparticipating ratepayers. The Commission seeks to minimize the

number of free riders taking advantage of discounted utility rates in Kentucky. Therefore, the Commission finds that utilities should have the ability to negotiate discounted rates with individual customers through the use of special contracts. This flexibility should enable the utilities to limit the number of EDRs they offer, thereby reducing the amount of foregone revenues resulting from discounted rates. Consequently, full contributions to system fixed costs would be made by some industrial customers that, under general EDR tariff provisions, would have automatically received rate discounts.

The Commission has previously approved EDR tariffs for Delta[26], Big Rivers[27], Green River[28], and Henderson-Union.[29] These utilities are hereby advised that the Commission will no longer require the implementation of EDRs through general tariffs. EDRs should now be implemented solely through special contracts negotiated with individual large commercial and industrial customers. The Commission finds that Delta, Big Rivers, Green River, and Henderson-Union should continue to honor all existing

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26 Delta's Economic Development Rate was initially approved in 1986. An extension of the tariff was subsequently approved on November 1, 1988.

27 Case No. 10424, The Notice of Big Rivers Electric Corporation of a Proposed Contract with Henderson-Union RECC to Implement an Industrial Incentive Rate.

28 Case No. 89-215, Green River Electric Corporation's Establishment of an Economic Development Rate.

29 Case No. 10422, The Notice of Henderson-Union RECC of a Proposed Contract with Valley Grain Products, Inc., to Implement an Industrial Incentive Plan.

contracts executed pursuant to an approved EDR tariff, but no new contracts related to an EDR tariff should be executed. Furthermore, each of these utilities should modify the availability clause of its EDR tariff to prohibit new customers after the date of this Order.

RISK ALLOCATION

Guideline 6 was developed to allocate fairly between utility shareholders and ratepayers the risk of revenue deficiencies created by discounted rates. A revenue deficiency is the difference between revenue which would have been received in the absence of an EDR (standard rates) and revenue actually received (discounted rates). The Commission sought to ensure that nonparticipating ratepayers were not negatively impacted by discounted rates. To accomplish this, the Commission ordered that utilities allocate at least one-half of all revenue deficiencies to their shareholders. This would likely have been achieved in a rate case by imputing to a utility's test-year revenue an amount equal to one-half of any revenue deficiency.

The participating utilities argue that if a discounted rate covers the marginal cost associated with serving an EDR customer and makes a contribution to system fixed costs, any difference between the regular tariff and the EDR should not be considered a deficiency and recovery of such revenues should not be imputed to the utility in rate proceedings. KPC states that all ratepayers will benefit from the economic improvements stimulated in part by

EDRs.[30] EKPC contends that EDR customers will not be receiving a subsidy from other ratepayers when their rate is equal to or greater than marginal cost.[31]

The Commission concludes that EDRs which are designed to recover all marginal costs and make a contribution to a utility's system fixed costs will benefit all nonparticipating ratepayers. Furthermore, the ratepayers of Kentucky are likely to enjoy additional benefits as a result of increased economic activity in the state. For these reasons, the Commission finds that a specific risk sharing mechanism designed to allocate revenue deficiencies to utility ratepayers and shareholders would be inappropriate and unnecessary. However, the Commission will continue to require all utilities with EDR contracts to demonstrate during rate proceedings that nonparticipating ratepayers are not adversely affected by EDR customers.

LOAD ELIGIBILITY

An important element in the development of an EDR program is the determination of which type load will be eligible for a rate discount. For new large commercial and industrial customers, an EDR is usually applied to all load in excess of a predetermined minimum usage level. For example, if required minimum usage levels are 1,000 KW per month for new electric customers and

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30 KPC's Response to the Commission's Order dated February 10, 1989, Item 12(c).

31 EKPC's Response to the Commission's Order dated February 10, 1989, Item 12(c).

100,000 Mcf per year for new gas customers, a new large commercial or industrial customer that initially contracts for more than 1,000 KW or 100,000 Mcf would qualify for an EDR on all KW or Mcf in excess of those minimum usage levels. For existing large commercial and industrial customers, new load in excess of a specific incremental usage level above a normalized base level may qualify for an EDR. For example, if required incremental usage levels are 1,000 KW per month for existing electric customers and 100,000 Mcf per year for existing gas customers, an existing customer that increases its load by more than 1,000 KW or 100,000 Mcf above its normalized base load would qualify for an EDR on all load in excess of the required incremental usage levels. EDRs applied to either of these type customers serve as an incentive for customers to locate or expand facilities and create new jobs.

The participating utilities agree that EDRs should apply both to the incremental load of existing customers and the load of new customers which exceed certain threshold amounts. All agree that an existing customer should be required to satisfy a minimum level of incremental load above a normalized base load and that new customers should be required to satisfy a minimum usage level before qualifying for EDRs. Most of the participating electric utilities state that a minimum incremental usage level of 1,000 KW above a normalized base load should be required for existing customers and a threshold usage level of 1,000 KW should be required of new customers. EKPC, however, suggests that lower levels be established. EKPC contends that by allowing loads in

excess of a minimum incremental usage level of 100 KW to qualify for an EDR, the opportunities for participation by smaller businesses increase significantly.[32] EKPC maintains that lower incremental usage levels would create an incentive for smaller industries in eastern Kentucky to expand, thereby providing more employment opportunities.

Columbia suggests that the threshold for an EDR offering to an existing gas customer be 100,000 Mcf per year of sustained new gas consumption of a high load factor.[33] The other participating gas utilities did not recommend a specific threshold amount.

The Commission concurs that the job creation potential of EDRs might be enhanced by setting required minimum usage levels as low as possible. Providing an opportunity for smaller commercial and industrial customers to qualify for EDRs would likely result in an increase in new jobs in Kentucky. In addition, free riders will be limited since minimum incremental usage requirements would be retained, although at lower levels.

The Commission will not attempt to determine specific minimum incremental usage levels required for existing customers or the base usage levels required for new customers. Rather, the Commission finds that utilities should have the flexibility to determine the usage levels that will best serve to promote economic development in their service areas. However, at the time

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32 EKPC's Response to the Commission's Order dated February 10, 1989, Item 3(b).

33 Columbia's Response to the Commission's Order dated February 10, 1989, Item 3(b).

an EDR contract is filed, the Commission will expect the utility to identify and justify the minimum incremental usage level and the normalized base load required for an existing customer or the minimum usage level required for a new customer, whichever is applicable. In its review of EDR contracts, the Commission will not only consider the customer's load which is eligible for an EDR, but also the number of new jobs, amount of new capital investment, and the general economic benefits associated with the new or expanding load.

RETENTION RATES

Several participating utilities maintain that EDRs should also be used for the retention of existing load. ULH&P contends that the economic benefits derived from a new customer are the same as those derived from the retention of an existing customer.[34] Big Rivers suggests that EDRs could work for the retention of customers.[35] EKPC expresses its support of the concept of retention rates and states that retaining existing customers is an essential economic development goal.[36]

The Commission finds that EDRs used for the purpose of retaining existing load should be strictly limited and closely monitored. Any utility that files such an EDR contract will also be expected to file a sworn affidavit of the customer stating

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34 Transcript of Evidence ("T.E."), page 133.

35 Id., page 97.

36 EKPC's Response to the Commission's Order dated February 10, 1989, Item 5.

that, in the absence of a discounted rate, business operations will cease or be severely restricted. The utility must also demonstrate the financial hardship experienced by the existing customer seeking discounted rates in order to maintain its load on the utility's system.

WAIVERS OF GAS MAIN EXTENSION COSTS

Western proposes that gas utilities be allowed to offer discounts or waivers of the costs of gas main extensions as an alternative to rate discounts.[37] Similarly, the Cabinet stresses the importance of gas utilities being allowed to assist industrial customers with gas main extensions.[38]

The Commission believes that inherent differences which exist between the services provided by gas and electric utilities might necessitate certain differences in the style and format of incentives offered to new and existing customers. Discounts or waivers of gas main extension costs could encourage new large commercial or industrial customers to locate in Kentucky. The Commission, therefore, finds that gas utilities proposing to offer a discount or waiver of gas main extension costs should provide a detailed cost-benefit analysis which compares, among other things, the total costs incurred by the utility by offering such a discount or waiver to the expected revenue stream from the new or expanding customer and the number of new jobs and the amount of

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37 Western's Response to the Commission's Order dated February 10, 1989, page 2.

38 T.E., page 17.

new capital investment to be created. Furthermore, the Commission finds that EDR contracts that include a discount or waiver of gas main extension costs should also include a provision which requires the customer to remain on gas service for a specified term. Gas utilities proposing to offer a discount or waiver of gas main extension costs should provide justification for the required contract term.

TERM OF EDR CONTRACTS

Some of the participating utilities have indicated that the term of an EDR contract should extend for a period of time following the end of the discount period. Service during the final years of the contract would be provided at the rates contained in the standard tariffs. This ensures that each EDR customer will contribute fully to system fixed costs during a portion of their special contract. KU contends that an EDR customer should agree to be served on a standard rate for a period of time commensurate with the discount period.[39] Big Rivers states that a total ten-year contract period should be allowed so that the utility will receive five years of standard rate revenues following a five-year discount period.[40] Finally, EKPC asserts that it would be appropriate to require a customer to sign a

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39 KU's Response to the Commission's Order dated February 10, 1989, Item 10.

40 Big Rivers' Response to the Commission's Order dated February 10, 1989, Item 10.

contract which extends for some period of time beyond the expiration of the discount period.[41]

The Commission concurs with these participating utilities and finds that an EDR contract should extend for a period twice the length of the discount period. Furthermore, the discount period should not extend beyond five years. During the second half of an EDR contract, the rates charged to the customer should be identical to those contained in a standard rate schedule that is applicable to the customer's rate class and usage characteristics.

CABINET'S PROPOSAL TO COMMENT ON EDR CONTRACTS

The Cabinet has suggested that it be afforded the opportunity to assist the Commission in its review of EDR contracts by providing comments on each filed EDR contract and the individual merits of the potential EDR customers.[42] The Cabinet asserts that some potential customers, especially those in declining industries, might not deserve an EDR.[43]

The Cabinet currently works closely with utilities in their efforts to locate industries in the state through the activities of an economic development task force known as the Kentucky Industrial Team ("Team").[44] In addition to locating industries in Kentucky, the Team, which is comprised of utility representatives,

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41 T.E., page 89.

42 Cabinet Testimony filed on May 31, 1980, page 5 and T.E., pages 21-22.

43 T.E., page 22.

44 Id., page 23.

Cabinet officials and local economic developers, helps prepare communities for industry.

The Commission acknowledges that Cabinet officials are experienced in dealing with economic development issues as they pertain to Kentucky communities. Furthermore, through its work with the Team, the Cabinet is likely involved in the development of economic development proposals and negotiations, possibly including EDRs, with new and existing large commercial and industrial customers. The Commission believes that comments submitted by the Cabinet pertaining to EDR contracts filed by utilities may be helpful and pertinent.

As stated in 807 KAR 5:011 Section 13, the Commission's regulations applicable to tariffs containing rates, rules and regulations, and general agreements, also apply to the rates and schedules set out in special contracts. Accordingly, the Commission has 30 days following the filing of a special contract during which it can accept, reject, or suspend the contract. Hence, in order to be sufficiently reviewed and considered by the Commission, any written comments prepared by the Cabinet or other interested parties pertaining to an EDR contract filed by a utility must be received by the Commission no more than 20 days after the filing of an EDR contract.

SUMMARY

The Commission, having considered the evidence of record and being otherwise sufficiently advised, finds that:

1. EDRs will provide important incentives to new large commercial and industrial customers to locate facilities in Kentucky and to existing large commercial and industrial customers to expand their operations, thereby bringing much needed jobs and capital investment into Kentucky.

2. Utilities should have the flexibility to design EDRs according to the needs of their customers and service areas and to offer EDRs to those new and existing customers who require such an incentive to locate new facilities in the state and to expand existing ones.

3. EDRs should be implemented by special contracts negotiated between the utilities and their large commercial and industrial customers.

4. An EDR contract should specify all terms and conditions of service including, but not limited to, the applicable rate discount and other discount provisions, the number of jobs and capital investment to be created as a result of the EDR, customer-specific fixed costs associated with serving the customer, minimum bill, estimated load, estimated load factor, and length of contract.

5. EDRs should only be offered during periods of excess capacity. Utilities should demonstrate, upon submission of each EDR contract, that the load expected to be served during each year of the contract period will not cause them to fall below a reserve margin that is considered essential for system reliability. Such a reserve margin should be identified and justified with each EDR contract filing.

6. Upon submission of each EDR contract, a utility should demonstrate that the discounted rate exceeds the marginal cost associated with serving the customer. Marginal cost includes both the marginal cost of capacity as well as the marginal cost of energy. In order to demonstrate marginal cost recovery, a utility should submit, with each EDR contract, a current marginal cost-of-service study. A current study is one conducted no more than one year prior to the date of the contract.

7. Utilities with active EDRs should file an annual report with the Commission detailing revenues received from individual EDR customers and the marginal costs associated with serving those individual customers.

8. During rate proceedings, utilities with active EDR contracts should demonstrate through detailed cost-of-service analysis that nonparticipating ratepayers are not adversely affected by these EDR customers.

9. All EDR contracts should include a provision providing for the recovery of EDR customer-specific fixed costs over the life of the contract.

10. The major objectives of EDRs are job creation and capital investment. However, specific job creation and capital investment requirements should not be imposed on EDR customers.

11. All utilities with active EDR contracts should file an annual report to the Commission providing the information as shown in Appendix A, which is attached hereto and incorporated herein.

12. For new industrial customers, an EDR should apply only to load which exceeds a minimum base level. For existing

industrial customers, an EDR shall apply only to new load which exceeds an incremental usage level above a normalized base load. At the time an EDR contract is filed, a utility should identify and justify the minimum incremental usage level and normalized base load required for an existing customer or the minimum usage level required for a new customer.

13. EDR contracts designed to retain the load of existing customers should be accompanied by an affidavit of the customer stating that, without the rate discount, operations will cease or be severely restricted. In addition, the utility must demonstrate the financial hardship experienced by the customer.

14. The term of an EDR contract should be for a period twice the length of the discount period, with the discount period not exceeding five years. During the second half of an EDR contract, the rates charged to the customer should be identical to those contained in a standard rate schedule that is applicable to the customer's rate class and usage characteristics.

15. Gas utilities proposing to offer a discount or waiver of gas main extension costs should provide a detailed cost-benefit analysis which compares, among other things, the expected revenue stream from the new or expanding customer and the number of new jobs and the amount of new capital investment to be created to the total costs incurred by the utility by offering such a discount or waiver.

16. EDR contracts that include a discount or waiver of gas main extension costs should include a provision which requires the customer to remain on gas service for a specified term. Gas

utilities proposing to offer a discount or waiver of gas main extension costs should provide justification for the required contract term.

17. Comments submitted by the Cabinet or other interested parties pertaining to EDR contracts should be filed with the Commission no more than 20 days following the filing of an EDR contract by a utility.

18. Delta, Big Rivers, Green River, and Henderson-Union should continue to honor all existing contracts executed pursuant to an approved EDR tariff, but no new contracts related to an EDR tariff should be executed. Each of these utilities should modify the availability clause of its EDR tariff to prohibit new customers after the date of this Order.

IT IS THEREFORE ORDERED that:

1. When filing EDR contracts, all jurisdictional gas and electric utilities shall comply with Findings 3-17 as if the same were individually so ordered.

2. Delta, Big Rivers, Green River, and Henderson-Union shall continue to honor all existing contracts executed pursuant to an approved EDR tariff, but no new contracts related to an EDR tariff shall be executed. Within 20 days of the date of this Order, each of these utilities shall file new economic development tariffs in which the availability clause has been modified to prohibit new customers after the date of this Order.

Done at Frankfort, Kentucky, this 24th day of September, 1990.

PUBLIC SERVICE COMMISSION

Chairman

Vice Chairman

Commissioner

ATTEST:

Executive Director

Attachment for Response to KIUC 2-36

APPENDIX A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN ADMINISTRATIVE CASE NO. 327 DATED 9/24/90

ECONOMIC DEVELOPMENT RATE CONTRACT REPORT

UTILITY: _____ YEAR: _____

	Current Reporting Period	Cumulative
1) Number of EDR Contracts -		
Total:		
Existing Customers:		
New Customers:		
2) Number of Jobs Created -		
Total:		
Existing Customers:		
New Customers:		
3) Amount of Capital Investment -		
Total:		
Existing Customers:		
New Customers:		

4) Consumption -

	Current Reporting Period	Cumulative
(A) DEMAND:		
Total:	KW | MCF	KW | MCF
Existing Customers:	KW | MCF	KW | MCF
New Customers:	KW | MCF	KW | MCF
(B) ENERGY/CONSUMPTION:		
Total:	KWH | MCF	KWH | MCF
Existing Customers:	KWH | MCF	KWH | MCF
New Customers:	KWH | MCF	KWH | MCF

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
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Item 37) *Refer to the Company's response to PSC 2-16 with respect to the* [redacted] *transaction.*

a. Please provide a current status report on this transaction, including the Company's quantifications of the net margin (gross revenues less variable costs) that the Company projects for each month during the term of the transaction.

b. Please provide the amount of the net margin included in the Company's test year revenue requirement, if any. Provide all assumptions, data, and computations, including electronic workpapers with formulas intact.

Response)

a. Big Rivers continues to have substantive conversations with [redacted] on this transaction. [redacted]

b. [redacted]

Witness) Robert W. Berry

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Item 38) ***Please provide a schedule of the Company's temporary investments at month end by type of investment from January 2011 through the most recent month for which actual information is available. Also provide the interest income for each month***

Response) Please see Attachment 1 to this response for temporary investment balances at month end by type of investment from January 2011 through August 2013 (the most recent month for which actual information is available). Please see Attachment 2 to this response for interest income on temporary investments, by investment, from January 2011 through August 2013.

Witness) Billie J. Richert

Big Rivers Electric Corporation
Case No. 2013-00199
Attachment 1 for Response to KIUC 2-38
Temporary Investment Account Balance by Month
January 2011 through August 2013 (Actuals)

Fidelity Prime Money Market Portfolio		**Balance**
January 31, 2011	$	49,446,794.11
February 28, 2011	$	55,863,997.10
March 31, 2011	$	91,374,566.59
April 30, 2011	$	61,495,379.40
May 31, 2011	$	67,021,168.92
June 30, 2011	$	76,437,057.24
July 31, 2011	$	71,255,941.68
August 31, 2011	$	76,636,038.16
September 30, 2011	$	77,682,827.02
October 31, 2011	$	58,882,050.09
November 30, 2011	$	55,158,644.95
December 31, 2011	$	44,843,790.64
January 31, 2012	$	46,610,515.67
February 29, 2012	$	49,465,745.85
March 31, 2012	$	49,461,159.10
April 30, 2012	$	40,761,628.52
May 31, 2012	$	39,621,359.09
June 30, 2012	$	47,652,971.03
July 31, 2012	$	105,756,525.84
August 31, 2012	$	107,521,746.13
September 30, 2012	$	113,244,033.84
October 31, 2012	$	117,329,395.78
November 30, 2012	$	112,017,886.54
December 31, 2012	$	110,165,436.23
January 31, 2013	$	112,281,637.63
February 28, 2013	$	116,720,184.82
March 31, 2013	$	116,374,045.17
April 30, 2013	$	124,602,977.78
May 31, 2013	$	66,559,167.02
June 30, 2013	$	67,033,862.95
July 31, 2013	$	72,002,136.90
August 31, 2013	$	78,293,021.06

Big Rivers Electric Corporation
Case No. 2013-00199
Attachment 2 for Response to KIUC 2-38
Interest Income on Temporary Investments by Month
January 2011 - August 2013 (Actuals)

Fidelity Prime Money Market Portfolio	**Interest Income**	
January 31, 2011	$	6,977.80
February 28, 2011	$	6,805.66
March 31, 2011	$	9,469.49
April 30, 2011	$	8,212.81
May 31, 2011	$	7,989.52
June 30, 2011	$	7,088.32
July 31, 2011	$	6,084.44
August 31, 2011	$	7,696.48
September 30, 2011	$	7,488.86
October 31, 2011	$	5,783.07
November 30, 2011	$	5,794.86
December 31, 2011	$	6,045.69
January 31, 2012	$	5,225.03
February 29, 2012	$	5,630.18
March 31, 2012	$	6,913.25
April 30, 2012	$	4,569.42
May 31, 2012	$	4,030.57
June 30, 2012	$	4,311.94
July 31, 2012	$	5,554.81
August 31, 2012	$	13,020.29
September 30, 2012	$	13,587.71
October 31, 2012	$	14,561.94
November 30, 2012	$	12,590.76
December 31, 2012	$	12,549.69
January 31, 2013	$	9,501.40
February 28, 2013	$	8,747.19
March 31, 2013	$	9,760.35
April 30, 2013	$	9,032.61
May 31, 2013	$	8,389.24
June 30, 2013	$	3,795.93
July 31, 2013	$	3,273.95
August 31, 2013	$	3,984.16

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Item 39) ***Please provide a schedule of the Company's temporary investments at month end by type of investment from January 2013 through December 2013 based on the Company's budget for 2013 and for January 2014 through December 2017 based on the corporate financial model forecast for those years consistent with the Company's rate filing proceeding. Also provide the interest income for each month.***

Response) Please see the attachment to this response for Big Rivers' temporary investments at month end by type of investment from January 2013 through December 2013 based on Big Rivers' budget for 2013. Please refer to the attachment to Big Rivers' response to PSC 2-19, page 11 of 23, for the interest income by month for January 2013 through December 2013 based on Big Rivers' budget for 2013.

Please refer to Big Rivers' "Financial Forecast (2014-2027) 5-16-2013" attached to Big Rivers' response to PSC 1-57, tab "Stmts RUS", rows 150 and 120, for Big Rivers' temporary investments at month end and interest income each month, respectively, for January 2014 through December 2017 based on the corporate financial model forecast for those years consistent with Big Rivers' rate filing proceeding.

Witness) Billie J. Richert

Big Rivers Electric Corporation
Case No. 2013-00199
Attachment for Response to KIUC 2-39
Temporary Investment Account Balances by Month (2013 Budget)

Fidelity Prime Money Market Portfolio *(Whole $)*	2013 Budgeted Amounts
January 31, 2013	$ 107,678,230.68
February 28, 2013	$ 110,082,574.25
March 31, 2013	$ 114,271,290.76
April 30, 2013	$ 113,780,230.67
May 31, 2013	$ 102,031,718.33
June 30, 2013	$ 101,933,779.94
July 31, 2013	$ 100,198,356.27
August 31, 2013	$ 94,012,694.20
September 30, 2013	$ 114,205,354.92
October 31, 2013	$ 105,976,444.82
November 30, 2013	$ 95,159,390.56
December 31, 2013	$ 82,843,418.27

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Item 40) *The Company included amortization expense of $102,110 to reflect a 5 year amortization of the capacity replacement charges projected for February 2014 through May 2014 assuming the shutdown of the Coleman plant. This amount is shown on Wolfram Reference Schedule 1.14. However, the Company excluded $442,329 in surcredit revenue for February 2014 through December 2014, according to Mr. Wolfram at 14.*

a. *Please confirm that if the Coleman plant is not shutdown during this period that the Company will not incur the capacity replacement charges.*

b. *Please indicate if there are any capacity replacement charges assuming the shutdown of the Wilson plan in the test year. If so, then please provide the charges by month and the total amount included in the test year revenue requirement.*

c. *Please provide the Company's best estimate at this time as to whether Coleman will be shutdown during some or all of the period February 2014 through January 2015. Describe the basis for the Company's best estimate and provide a copy of all documentation that addresses whether Coleman will be shutdown during this period.*

d. *Please provide the Company's best estimate at this time as to whether Wilson will be shutdown during some or all of the period February 2014*

through January 2015. Describe the basis for the Company's best estimate and provide a copy of all documentation that addresses whether Coleman will be shutdown during this period.

e. *Mr. Wolfram states at 14 that "the surcredit [revenue] amounts in the forecast test period are non-recurring and should be eliminated." Please explain why the capacity replacement charges should not be eliminated given that they too are nonrecurring.*

Response)

a. Confirmed.

b. Big Rivers could incur capacity replacement charges from February 1, 2014 through May 31, 2014 if Wilson is shutdown during the forecasted test period of February 1, 2014 through January 31, 2015. The costs incurred would depend on whether Coleman was idled between February and May 2014. Big Rivers has 552 unused MISO Zonal Resource Credits (ZRCs) that could be used to satisfy MISO capacity replacement requirements. To idle Coleman prior to May 31, 2014 would require 425.4 replacement ZRCs. To idle Wilson prior to May 31, 2014 would require 402.4 replacement ZRCs. ZRCs

would have to be acquired bilaterally in the market to the extent Big Rivers needed more than 552 ZRCs. The bilateral market for MISO ZRC is illiquid; however, as shown in response to PSC 2-21 Big Rivers estimated the cost at $12/MW-day.

c. Big Rivers requested, via a MISO Attachment Y notification, that Coleman be idled September 1, 2013 through December 31, 2015. MISO subsequently determined in their Attachment Y Study Report, provided in response to KIUC 1-46e, that Coleman could not be idled due to reliability concerns. Should Century Aluminum successfully install and receive necessary regulatory approvals and reduce load to a level as determined by MISO, Coleman would no longer be needed for reliability. Century expects these actions to be complete by May 31, 2014. Therefore Coleman is currently expected to be idled June 1, 2014 through December 31, 2015.

d. Big Rivers requested that Wilson be idled beginning February 1, 2014. Big Rivers has not yet received final notification from MISO on whether Wilson will be required to operate for reliability. Big Rivers' request to MISO was based on Century Sebree (formerly Alcan), giving notice to terminate its

Retail Electric Service Agreement with Kenergy and cease operations effective February 1, 2014.

e. The smelter surcredit revenue amounts are coupled with the smelter surcharge amounts and should be eliminated in order to comply with the matching principle, since both the surcharge and surcredit amounts stem from the smelter contracts, which have been terminated. Please see the responses to PSC 2-24 and PSC 3-4. The capacity replacement charges are different and should not be eliminated because such treatment is consistent with the Commission's practice of amortizing prudently-incurred "extraordinary" expenses over a five-year period. As the Commission has explained, "Historically, the Commission has exercised its discretion to approve regulatory assets where a utility has incurred: (1) an extraordinary, nonrecurring expense which could not have reasonably been anticipated or included in the utility's planning; (2) an expense resulting from a statutory or administrative directive; (3) an expense in relation to an industry sponsored initiative; or (4) an extraordinary or nonrecurring expense that over time will

result in a saving that fully offsets the cost."[1] It is appropriate for the Commission to allow Big Rivers to recover the amortized portion of the non-recurring capacity charges as an extraordinary expense "which could not have been reasonably anticipated or included in the utility's planning" because the one-time expense of $510,522 for these costs in the test period is prudent, material, and could not have been reasonably anticipated by Big Rivers before the smelter contract termination notice was provided.

Witnesses) Lindsay N. Barron (a-b), Robert W. Berry (c-d), and John Wolfram (e)

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

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Item 41) ***Refer to the Company's response to KIUC 1-24 regarding steps taken or that will be taken to reduce the Company's property tax expense on the Wilson and Coleman plants.***

a. ***Please provide the Company's understanding of the statutory bases for the valuation of the Company's property for property tax purposes.***

b. ***Please provide the Company's understanding of all other bases for the valuation of the Company's property for property tax purposes.***

c. ***Please describe the Company's understanding as to the methods and the application of the methods used by each of the applicable taxing authorities for the valuation of the Wilson and Coleman plants for property tax purposes in 2011, 2012, and 2013.***

d. ***Please confirm that one method used to determine the valuation of the Company's property for property tax purposes is the income method whereby the tax assessor computes the valuation based on the net present value of the future income stream of the property.***

e. ***Please confirm that one method used to determine the valuation of the Company's property for property tax purposes is the market value whereby***

the tax assessor computes the valuation by using comparables or other sources of market value.

f. Please provide all evidence that the market value of the Wilson and Coleman plants is greater than or equal to the net book value of those plants.

g. Please explain why the Company has taken no steps to appeal and/or negotiate downward the valuation of the Wilson and Coleman plants for property tax purposes knowing that it intends to shut down both plants.

Response) Big Rivers objects to this request on the grounds that it is overly broad and unduly burdensome. Big Rivers also objects to this request on the grounds that it seeks information that is protected by the attorney-client and attorney work product privileges. Notwithstanding these objections, but without waiving them, Big Rivers states as follows:

a. In accordance with Section 172 of the Kentucky Constitution, and Chapter 132, Section 191 of the Kentucky Revised Statutes ("KRS"), the Kentucky Department of Revenue ("Department of Revenue") determines property value using a variety of valuation methods, including but not limited to:

(1) A cost approach, which is a method of appraisal in which the estimated value of the land is combined with the current depreciated reproduction or replacement cost of improvements on the land.

(2) An income approach, which is calculated using thirteen different averaging methods to estimate the pretax operating income. These thirteen income values are then averaged to arrive at a final income amount. From this final income amount, an estimated pretax operating income is determined for the current tax year and is used to calculate the unit value of the property based the following equation: The sum of (estimated pretax operating income + depreciation + amortization) divided by the capitalization rate plus the construction work-in-progress plus the value of operating leased property. The capitalization rate is determined using value lines and the Forbes rate. The capitalization rate may change from year to year.

(3) A correlated value approach, in which the assessed value is calculated by weighting each of the values derived from the cost approach and the income approach. The weight is determined by the assessor based upon the current situation of each company.

(4) A sales comparison approach, which is a method of appraisal based on comparison of the property with similar properties sold in the recent past.

b. Other bases for valuation used for property tax purposes include net book value. Net book value is the historical cost less the accumulated book depreciation.

c. In 2011, 2012 and 2013, the Wilson and Coleman plants were assessed at net book value for property tax purposes.

d. The Department of Revenue has used the income approach method described above as a tool to determine the valuation of Big Rivers' property for property tax purposes.

e. The Department of Revenue has not used the market approach as a tool to determine the valuation of Big Rivers' property for property tax purposes.

f. Information regarding the market value of the Wilson and Coleman plants was produced in Big Rivers' response to PSC 2-18 in Case No. 2012-00535. The best evidence of market value exists when there is a good faith offer to purchase the plants at a particular price. Any other information is simply an estimate of market value.

g. Big Rivers has not taken steps to appeal and/or negotiate downward the current valuation of the Wilson and Coleman plants for property tax purposes because Big Rivers is still operating those plants. Although Big Rivers anticipates that the statuses of these plants will change, the details of these status changes depend on a number of variables, including third-party business decisions, Public Service Commission orders, and the implementation of Big Rivers' Load Concentration and Mitigation Plan. In light of these contingencies, Big Rivers' management determined that a challenge of the Wilson and Coleman plant property taxes would be premature and would constitute an inefficient use of resources at this time; however, Big Rivers has been and will continue to be diligent about ensuring the accuracy of its property tax assessments.

During 2009 and years prior, when the valuation of Big Rivers' plants for property tax purposes was based on income and cost valuation methodologies, Big Rivers filed protest letters with the Department of Revenue disputing the property valuation assessments for property tax purposes during those years. In those protest letters Big Rivers proposed using net book value as the assessed property value for property tax purposes,

which was lower than the assessed value based on the income and cost valuation methodologies used. Since 2010, when the Department of Revenue began using net book value for property tax purposes, as proposed by Big Rivers in previous years, Big Rivers has not protested the valuation assessments for property tax purposes.

Witness) Billie J. Richert

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Item 42) ***Refer to the Company's response to KIUC 1-42(a);***

a. ***Please describe the capital expenditures shown for the Wilson plant in 2014. Are these related solely to the layup in the same manner that the capital expenditures for the Coleman plant are related solely to the layup?***

b. ***Please indicate if any of the capital expenditures shown for HAP/MATS in 2014 are for the Wilson or Coleman plants. If so, then provide the amounts for each plant in 2014 and explain why these capital expenditures will not be delayed until a later date commensurate with a return to service of the plants.***

Response)

a. Please see Exhibit Berry-2 in the Direct Testimony of Robert W. Berry for a description of the capital expenditures shown for the Wilson plant in 2014. The capital expenditures shown for the Wilson plant in Exhibit Berry-2 are not solely related to the layup. The current Wilson Station 2013-2016 capital plan was developed in 2012 when there was still much uncertainty surrounding the timing of the unit lay-up and its return to service. The 2014-2017 Wilson Station capital plan that will be presented to the Big Rivers

Board for approval in November 2013 will include only layup related expenditures for Wilson in 2014, and will not include any capital dollars for Wilson in 2015 or 2016.

b. There is $[redacted] for Wilson MATS and $[redacted] for Coleman MATS included in this number (before capitalized interest). These figures were included in the original 2013 capital expenditure budget, which is the basis for Big Rivers' response to KIUC 1-42(a). As a result of termination of the smelter contracts by Century and Rio Tinto, and the subsequent uncertainty over future operation of these plants, Big Rivers' management agrees that the MATS capital expenditures for Wilson and Coleman should be delayed until a later date that supports the return to service of these plants.

Witness) Robert W. Berry

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Item 43) ***Refer to the Company's response to AG 1-41 showing the dates of the most recent actual and scheduled outages due to maintenance on the Company's transmission lines.***

a. ***For each of the transmission lines, please provide the dates of the actual 2013 outages and the projected dates in 2013 for any outages that have not yet occurred.***

b. ***For each of the transmission lines, please provide the actual maintenance expense for each outage that has occurred in 2013 and provide the projected maintenance expense for each outage that has not yet occurred in 2013.***

Response)

a. An outage of the Coleman to Newtonville 161 kV line was taken on July 8, 2013, August 19, 2013 and August 28, 2013 to perform line maintenance and related substation maintenance. Additional outages are necessary to complete the maintenance work in mid-October. The Coleman EHV to Daviess EHV 345 kV line was taken out of service on May 1, 2013 and May 2, 2013. Additional outages are necessary to complete planned maintenance work

[redacted]

[redacted]. Outages of the Coleman EHV to Coleman 161 kV lines were taken on August 29, 2013 (C1 line) and September 3, 2013 (C2 line) to perform line maintenance and related substation maintenance work. Additional outages are necessary to complete the planned maintenance work [redacted]. No outages have been taken in 2013 to perform line maintenance on the Reid to Daviess County 161 kV line. Planned outages to perform line maintenance will be necessary in mid-October.

b. The 2013 actual and forecasted line maintenance expenses for each requested line follows:

	Actual 2013 Expense Through September 20, 2013	Remaining Expenses Forecasted for 2013
CEHV to Coleman 161 kV 1 & 2	$7,145	[redacted]
Coleman to Newtonville 161 kV	$16,984	[redacted]
Reid to Daviess Co. 161 kV	n/a	[redacted]
DEHV to CEHV 345 kV	$41,730	[redacted]

Witness) Christopher S. Bradley

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2013-00199

Response to the Kentucky Industrial Utility Customers, Inc.'s
Second Request for Information
dated September 16, 2013

September 30, 2013

Item 44) ***Refer to the Company's response to SC 1-25 and the description of the Company's model inputs for developing the rural peak demand model starting at the bottom of page 3 and continuing on the top of page 4 of this response. Please provide all support for the 50% reduction in the elasticity effect for peak load compared to the elasticity effect for energy.***

Response) Big Rivers did not perform an analysis to determine elasticity of demand with respect to electricity prices. The 50% reduction in the elasticity effect for peak demand relative to the effect for energy is based on the assumption that the impacts of customer efforts to cut consumption due to price increases will be achieved predominately during non-peaking hours rather than during peaking periods.

Witness) Lindsay N. Barron

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2013-00199

Response to the Kentucky Industrial Utility Customers, Inc.'s
Second Request for Information
dated September 16, 2013

September 30, 2013

Item 45) *Please refer to the model inputs and outputs provided in response to SC 1-25.*

a. *Please confirm that GDS determined the price elasticity effect based on historic price data for Big Rivers from 1995-2012.*

b. *Please confirm that the historic price data reflects essentially flat or declining prices for all years until 2012.*

c. *What is the rationale for assuming that the magnitude of the combined price increases on an "all-in" basis resulting from the loss of the Century and Alcan loads will have the same elasticity effects on average as the historical period where price changes were not of this magnitude? Please provide all support relied on for your response.*

d. *Please describe the price elasticity analyses the Company performed for the commercial customers in the Rural class, if any. If none, please confirm that the Company agrees that residential and commercial customers have different price elasticity responses.*

e. *Please confirm that the Company's price elasticity analyses do not address the loss or addition of customers, but rather address the average customer energy usage for actual customers in the historic years.*

Response)

a. Price elasticity effects result from the application of the price elasticity coefficient (a ratio) to the anticipated rate adjustments. In this study, the price elasticity coefficient was determined for each of Big Rivers' three member distribution cooperatives using regression analysis. The model developed for JPEC was based on data from 1995-2012. The model developed for Kenergy was based on data from 1991-2012. The model developed for Meade County Rural Electric Cooperative Corporation was based on data from 2003-2012. Then, the price elasticity coefficients were applied to the anticipated rate adjustments related to the instant proceeding. Thus, while the price elasticity coefficients are derived from historical data, the price elasticity impacts are related to the anticipated rate adjustments that correspond to the instant filing.

b. The average price of electricity, expressed in deflated terms, demonstrated a general negative trend through 2007-2008, depending on cooperative, and a general upward trend thereafter.

c. Big Rivers conducted a search for information and/or studies that identified changes in price impacts between periods with moderate price changes and

periods with significantly larger price changes. Big Rivers identified no information or studies that specifically addressed changes in price elasticity given significant changes in price relative to prior years; therefore, the price elasticity coefficients derived for the historical period through the regression models were assumed to be the same during the forecast period. Note, however, that while the price elasticity coefficients rely on the historical data, the price elasticity effects result from the application of those coefficients to the anticipated rate adjustments corresponding to the instant filing.

d. The price elasticities derived through the regression models were for all rural system customers, which includes residential and commercial customers. No specific analysis was conducted for the residential or commercial class; therefore, Big Rivers cannot confirm differences in the price elasticity between the two classes, if any.

e. Confirmed.

Witness) Lindsay N. Barron

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2013-00199

Response to the Kentucky Industrial Utility Customers, Inc.'s
Second Request for Information
dated September 16, 2013

September 30, 2013

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a. Please confirm that GDS determined the price elasticity effect based on historic price data for Big Rivers from 1995-2012.

b. Please confirm that the historic price data reflects essentially flat or declining prices for all years until 2012.

c. What is the rationale for assuming that the magnitude of the combined price increases on an "all-in" basis resulting from the loss of the Century and Alcan loads will have the same elasticity effects on average as the historical period where price changes were not of this magnitude? Please provide all support relied on for your response.

d. Please describe the price elasticity analyses the Company performed for the commercial customers in the Rural class, if any. If none, please confirm that the Company agrees that residential and commercial customers have different price elasticity responses.

e. Please confirm that the Company's price elasticity analyses do not address the loss or addition of customers, but rather address the average customer energy usage for actual customers in the historic years.

Response)

a. Price elasticity effects result from the application of the price elasticity coefficient (a ratio) to the anticipated rate adjustments. In this study, the price elasticity coefficient was determined for each of Big Rivers' three member distribution cooperatives using regression analysis. The model developed for JPEC was based on data from 1995-2012. The model developed for Kenergy was based on data from 1991-2012. The model developed for Meade County Rural Electric Cooperative Corporation was based on data from 2003-2012. Then, the price elasticity coefficients were applied to the anticipated rate adjustments related to the instant proceeding. Thus, while the price elasticity coefficients are derived from historical data, the price elasticity impacts are related to the anticipated rate adjustments that correspond to the instant filing.

b. The average price of electricity, expressed in deflated terms, demonstrated a general negative trend through 2007-2008, depending on cooperative, and a general upward trend thereafter.

c. Big Rivers conducted a search for information and/or studies that identified changes in price impacts between periods with moderate price changes and

periods with significantly larger price changes. Big Rivers identified no information or studies that specifically addressed changes in price elasticity given significant changes in price relative to prior years; therefore, the price elasticity coefficients derived for the historical period through the regression models were assumed to be the same during the forecast period. Note, however, that while the price elasticity coefficients rely on the historical data, the price elasticity effects result from the application of those coefficients to the anticipated rate adjustments corresponding to the instant filing.

d. The price elasticities derived through the regression models were for all rural system customers, which includes residential and commercial customers. No specific analysis was conducted for the residential or commercial class; therefore, Big Rivers cannot confirm differences in the price elasticity between the two classes, if any.

e. Confirmed.

Witness) Lindsay N. Barron

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2013-00199

Response to the Kentucky Industrial Utility Customers, Inc.'s
Second Request for Information
dated September 16, 2013

September 30, 2013

Item 46) ***Please refer to the Company's response to AG 1-52 page 3 of 64.***

a. ***Please provide a copy of the Company's revised capitalization policy.***

b. ***Please identify and describe all reasons for revising the Company's capitalization policy.***

c. ***Please indicate whether the test year expense in the Company's filing reflects the Company's revised capitalization policy.***

d. ***If the response to part (c) of this question is that it does not, then please provide a quantification of the pro forma expense that would be necessary to reflect the Company's revised capitalization policy.***

Response:

a. Please see the attached document for a copy of Big Rivers' revised capitalization policy, effective July 2013.

b. Big Rivers' capitalization policy reflects the following revisions:

- Incorporates three separate existing policies related to Capital Expenditures, Capitalized Spare Parts, and Capitalized Interest into a single Capitalization Policy.

- Documents the dollar and percentage criteria agreed to at the "Unwind" and currently being applied in making capitalization versus O&M expenditure decisions.
- Provides references to the applicable RUS regulations and Generally Accepted Accounting Principles that establish the accounting requirements that the Capitalization Policy must follow. In addition, provides a listing of the debt provisions that require that accounting records are maintained in accordance with RUS and GAAP accounting requirements.

c. Yes, Big Rivers' filing reflects the revised capital policy.

d. Please see Big Rivers' response to subpart (c).

Witness) Billie J. Richert

Attachment for Response to KIUC 2-46
Big Rivers revised capitalization policy

Scope: Big Rivers Electric Corporation's ("Big Rivers" or "Company") Capitalization Policy establishes guidance related to costs to be capitalized and reported in "Electric Plant in Service" (account 101). Capitalized costs consist of both direct costs (e.g. labor, materials, supplies, equipment, services, etc.) and indirect costs (e.g. overheads, funding costs, etc.) attributable to the acquisition, construction and improvements of electric plant. The Rural Utilities Service (RUS) regulations have established guidelines to be followed in determining whether expenditures incurred are to be capitalized as electric plant or expensed as maintenance. In addition, Generally Accepted Accounting Principles (GAAP) have established standards of financial accounting and reporting for capitalizing interest on certain additions to electric plant. Big Rivers' Capitalization Policy is structured to assist in the determination of what constitutes *Capital Expenditures* and under what criteria *Capitalized Interest* will be charged to construction projects.

Capital Expenditures — include direct purchase expenditures (i.e. electric plant requiring no or minimal installation), construction expenditures (i.e. electric plant requiring installation), and capitalized spare parts. The guidance for determination of capital expenditures (whether individually or in combination) that constitute electric plant assets are defined in ***Section A – Capital Expenditures*** on page 3.

Capitalized interest — allowance for funds used during construction is included on projects with an estimated total cost of $250,000 or more before consideration of such allowance. The interest capitalized is determined by applying Big Rivers' effective weighted average interest rate on long term debt to the accumulated expenditures for qualifying projects included in construction work in progress. The guidance for determination of when interest should be capitalized on electric plant assets and the determination of the amount of interest is defined in the policy set out in ***Section B – Capitalized Interest*** on page 7.

Regulations Applicable
Rural Utilities Service (RUS):
7 CFR Part 1767—*Accounting Requirements for RUS Electric Borrowers*
Subpart B—*Uniform System of Accounts* (RUS Bulletin 1767 B-1)

Kentucky Public Service Commission (KPSC):
KRS 278.220—*Uniform system of accounts for utilities* (as applied to Big Rivers the KPSC has adopted the RUS *Uniform System of Accounts*)

Generally Accepted Accounting Principles
Financial Accounting Standards Board:
FASB ASC 835-20—*Interest – Capitalization of Interest*
(formerly SFAS 34 *Capitalization of Interest Cost*)
Debt Provisions Applicable

Indenture —Section 1.1(H) *Accounting Requirements* (defined) | Section 13.10 *To Keep Books; Inspection by Trustee*

RUS—Amended and Consolidated Loan Contract—Section 4.5 *Financial Books* | (see Indenture).

CFC—Secured Term Loan—Section 5.01(C)(vi) *Financial Books; Financial Reports; Right of Inspection* | (see Indenture).

CoBank—Secured Term Loan—Section 6.01 *Financial Reports* | Section 7.03 *Accounting Changes* | (see Indenture).

US Bank—2010A Bonds—(see Indenture).

CFC—Unsecured Revolving Credit Agreement—Section 5.01(D) *Financial Books; Financial Reports; Right of Inspection* | Section 5.01(E) *Compliance With Laws.*

CoBank—Unsecured Revolving Credit Agreement— Section 6.01 *Financial Reports* | Section 7.05 *Accounting Changes*

NOTE: An Authorization for Investment Proposal (AIP) is required when purchasing, constructing, fabricating, modifying, installing, or removing capital facilities or equipment. Capital purchases and projects are subject to the AIP process and are not considered approved until an AIP Form is submitted and proper approvals are obtained through that process. Therefore, no capital costs covered by this Capitalization Policy shall be incurred until the requirements of the AIP Policy have been met.

Section A – Capital Expenditures

1. Purpose

This section of Big Rivers' Capitalization Policy is to establish guidance for determining when expenditures are to be capitalized to "Electric Plant in Service" (account 101) as opposed to being expensed to operations or maintenance.

This guidance is based on the codified policies and procedures found in 7CFR Part 1767, *Accounting Requirements for RUS Electric Borrowers*, and the requirements set out in Section 3.15 (*Big Rivers Capitalization Policy*) of the Smelter Coordination Agreements. (Appendix A contains the definitions of certain terms used in this policy. Appendix B contains the text of Sections of 7 CFR Part 1767 cited in this policy and the text of Section 3.15 of the Smelter Coordination Agreements concerning Big Rivers Capitalization Policy).

2. Policy

RUS accounting requirements state: *For the purpose of avoiding undue refinement in accounting for additions to and retirements and replacements of electric plant, all property shall be considered as consisting of retirement units and minor items of property [7 CFR Part 1767 Subpart B § 1767.16(j)(1)].*

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

a. New retirement unit
b. Retirement unit replacement
c. Retirement system addition
d. Retirement system replacement
e. New minor property item
f. Minor property item replacement with betterment
g. Computer software and software upgrades
h. Capitalized Spare Parts
i. Capital in accordance with the Smelter Coordination Agreement in Section 3.15

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

Note: Dollar values and percentages can be updated with senior management approval. However, changes should be supported by the reasons for such changes, explaining the deviation from consistency in applying the policy.

3. Rules

a. New Retirement Unit — *7 CFR Part 1767 Subpart B §1767.16(j)(2)*

1. Cost more than $2,000 in Steam and Other Production Plant or $500 in other accounts, and
2. Be readily separable and separately useable, and
3. Have an expected useful life of more than one year.

b. Retirement Unit Replacement — *7 CFR Part 1767 Subpart B §1767.16(j)(2)* and *7 CFR Part 1767 Subpart B §1767.16(j)(3)(i)*

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

c. Retirement System Addition — *7 CFR Part 1767 Subpart B §1767.16(j)(2)*

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

d. Retirement System Replacement — *7 CFR Part 1767 Subpart B §1767.16(j)(2)* and *7 CFR Part 1767 Subpart B §1767.16(j)(3)(i)*

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

e. New Minor Property Item — *7 CFR Part 1767 Subpart B §1767.16(j)(3)(i)*

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

f. Minor Property item Replacement with Betterment — *7 CFR Part 1767 Subpart B §1767.16(j)(3)(iii)*

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

g. Computer Software and Software Upgrades *7 CFR Part 1767 Subpart B §1767.16(j)(2)* and *7 CFR Part 1767 Subpart B §1767.16(j)(3)(i)*

1. Capitalize any <u>new</u> software purchase of $2,000 or more if used with a computer associated with Steam and Other Production Plant operations or $500 or more if used for any other computer as long as the new software has a useful life of more than one year.
2. Any software <u>upgrade</u> should be capitalized if the cost of the upgrade exceeds 25% of the software which it will become a part or $10,000 the smaller of the two. The 25% must be $2,000 or more if used with a computer associated with Steam and Other Production Plant operations or $500 or more if used for any other computer. The software upgrade must have a life of more than one year.

h. Capitalized Spare Parts — *7 CFR Part 1767 Subpart B §1767.16(j)(3)(i)*

Determining when to capitalize a spare part as a minor property item as opposed

to expense through the inventory system.

To be capitalized, a spare part must meet all of the following guidelines:

1. Parts have to be purchased or ordered prior to the commercial operation date of the equipment for which they are designed.
2. Parts are considered critical and peculiar to the original equipment so as to result in unacceptable downtime when needed.
3. Parts are purchased with the intention of being retired along with the equipment for which they were designed and are not subject to any periodic, frequent, or anticipated replacements.
4. Parts can usually be restored to serviceable condition (refurbished) in the event of use.
   Note: Valves that are requisitioned, including those inventoried, which cost more than $2,000 and are over 2" in size are to be capitalized.

i Retirement Unit in accordance with the Smelter Coordination Agreement in Section 3.15

§3.15 Big Rivers Capitalization Policy. To the extent consistent with Accounting Principles, Applicable Law and guidance of applicable Governmental Authorities or RUS, Big Rivers shall capitalize expenditures for the replacement of the items related to Big Rivers' generation facilities identified in the list of the retirement units set forth in the Schedule 3.15. (text taken from the Smelter Coordination Agreement)

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

Section B – Capitalized Interest

1. Purpose

This section of Big Rivers' Capitalization Policy is to establish guidance for determining when interest should be capitalized on construction (installation) projects and determining the amount of interest to be capitalized for inclusion in "Electric Plant in Service" (account 101) as a cost of an electric plant asset.

This guidance is based on the FASB ASC 835-20 *Interest – Capitalization of Interest* (formerly SFAS 34 *Capitalization of Interest Cost*). FASB ASC 835-20 establishes financial accounting and reporting criteria for capitalizing interest cost as a part of the historical cost of acquiring certain electric plant assets.

2. Policy

The objectives of capitalizing interest are (a) to obtain a measure of acquisition cost that more closely reflects Big Rivers' total investment to bring an item of property to the condition and location necessary for its intended use, and (b) to charge a cost that relates to the acquisition of a resource that will benefit future periods against the revenues of the periods benefited.

It is the policy of Big Rivers to capitalize interest as follows:

1. The Company will capitalize interest on any construction (installation) project which meets both of the following criteria: (a) estimated total cost of $250,000 or more (excluding consideration of capitalized interest) and (b) requires more than a minimal amount of construction (installation) time.

2. The amount of interest to be capitalized for a qualifying construction project is that portion of interest cost incurred during the project's construction period that could have been avoided if expenditures for that project had not been made.

3. The amount of interest capitalized during a month shall be determined by applying an interest rate (the capitalization rate) to the amount of to-date accumulated expenditures for qualifying construction projects as described below:

    a. The capitalization rate used shall be Big Rivers' monthly effective weighted average interest rate on long term debt.

    b. Accumulated expenditures, to be included in the calculation of monthly capitalized interest for a project, is calculated as set out below:

        Prior month project balance in construction work in progress (CWIP)

(+) ½ current month project expenditures
(-) Retainage
(-) Internal labor costs
(-) Capitalized interest previously recorded
(=) Accumulated expenditures

4. The capitalization of interest shall start when both the first dollar is expended and the construction has begun on the qualifying project.

5. The capitalization of interest shall cease when the qualifying construction project is substantially complete and ready for its intended use.

6. The capitalization of interest shall be suspended on a qualifying construction project during any period in which no activity necessary to ready the project for its intended use is taking place. Notify the Finance/Accounting department if this situation occurs.

Appendix A

Definitions:

Retirement Unit – those items of electric plant which, when retired with or without replacement, are accounted for by removing its cost from the plant account in which included.

Minor Property Item - the associated parts or items of which retirement units are composed. The addition and retirement of minor items of property shall be accounted for as defined in this capitalization policy.

Record Unit - unit designed for accounting convenience and to facilitate record keeping of plant costs on a practical basis. It is never smaller than a retirement unit but is sometimes a combination of associated retirement units serving a single basic operating purpose.

Attachment for Response to KIUC 2-46
Big Rivers revised capitalization policy

Appendix B

Code of Federal Regulations

Title 7: Agriculture

PART 1767—ACCOUNTING REQUIREMENTS FOR RUS ELECTRIC BORROWERS
Subpart B—Uniform System of Accounts

§1767.16* (j) *Additions and retirements of electric plant.

(1) For the purpose of avoiding undue refinement in accounting for additions to and retirements and replacements of electric plant, all property shall be considered as consisting of retirement units and minor items of property.

(2) The addition and retirement of retirement units shall be accounted for as follows:

(i) When a retirement unit is added to electric plant, the cost thereof shall be added to the appropriate electric plant account, except that when units are acquired in the acquisition of any electric plant constituting an operating system, they shall be accounted for as provided in paragraph (e) of this section.

(ii) When a retirement unit is retired from electric plant, with or without replacement, the book cost thereof shall be credited to the electric plant account in which it is included, determined in the manner set forth in Item in paragraph (j)(4) of this section. If the retirement unit is of a depreciable class, the book cost of the unit retired and credited to electric plant shall be charged to the accumulated provision for depreciation applicable to such property. The cost of removal and the salvage shall be charged or credited, as appropriate, to such depreciation account.

(3) The addition and retirement of minor items of property shall be accounted for as follows:

(i) When a minor item of property which did not previously exist is added to plant, the cost thereof shall be accounted for in the same manner as for the addition of a retirement unit, as set forth in Item in paragraph (j)(2)(i) of this section, if a substantial addition results, otherwise the charge shall be to the appropriate maintenance expense account.

(ii) When a minor item of property is retired and not replaced, the book cost thereof shall be credited to the electric plant account in which it is included; and, in the event the minor item is a part of depreciable plant, the account for accumulated provision for depreciation shall be charged with the book cost and

cost of removal and credited with the salvage. If, however, the book cost of the minor item retired and not replaced has been or will be accounted for by its inclusion in the retirement unit of which it is a part when such unit is retired, no separate credit to the property account is required when such minor item is retired.

(iii) When a minor item of depreciable property is replaced independently of the retirement unit of which it is a part, the cost of replacement shall be charged to the maintenance account appropriate for the item, except that if the replacement effects a substantial betterment (the primary aim of which is to make the property affected more useful, more efficient, of greater durability, or of greater capacity), the excess cost of the replacement over the estimated cost at current prices of replacing without betterment shall be charged to the appropriate electric plant accounts.

(4) The book cost of electric plant retired shall be the amount at which such property is included in the electric plant accounts, including all components of construction costs. The book cost shall be determined from the utility's records and if this cannot be done, it shall be estimated. When it is impracticable to determine the book cost of each unit, due to the relatively large number or small cost thereof, an appropriate average book cost of the units with due allowance for any differences in size and character, shall be used as the book cost of the units retired.

(5) The book cost of land retired shall be credited to the appropriate land accounts. If the land is sold, the difference between the book cost (less any accumulated provision for depreciation or amortization therefore which has been authorized and provided) and the sale price of the land (less commissions and other expenses of making the sale) shall be recorded in Account 411.6, Gains from Disposition of Utility Plant, or Account 411.7, Losses from Disposition of Utility Plant, when the property has been recorded in Account 105, Electric Plant Held for Future Use, otherwise to Accounts 421.1, Gain on Disposition of Property, or 421.2, Loss on Disposition of Property, as appropriate. If the land is not used in utility service but is retained by the utility, the book cost shall be charged to Account 105, Electric Plant Held for Future Use, or Account 121, Nonutility Property, as appropriate.

(6) The book cost less net salvage of depreciable electric plant retired shall be charged in its entirety to Account 108, Accumulated Provision for Depreciation of Electric Utility Plant in Service. Any amounts which, by approval or order of RUS, are charged to Account 182.1, Extraordinary Property Losses, shall be credited to Account 108.

(7) The accounting for the retirement of amounts included in Account 302, Franchises and Consents, and Account 303, Miscellaneous Intangible Plant, and the items of limited-term interest in land included in the accounts for land and land rights, shall be as

provided for in the text of Account 111, Accumulated Provision for Amortization of Electric Utility Plant in Service; Account 404, Amortization of Limited-Term Electric Plant; and Account 405, Amortization of Other Electric Plant.

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES CASE NO. 2013-00199

Response to the Kentucky Industrial Utility Customers, Inc.'s Second Request for Information dated September 16, 2013

September 30, 2013

Item 47) ***Please refer to the Company's response to AG 1-52 page 5 of 64.***

a. ***Please provide a quantification of the savings from the termination of the CoBank line of credit. Provide all assumptions, data, computations, including electronic spreadsheets with formulas intact.***

b. ***Please indicate whether the savings from the termination of the CoBank line of credit are reflected in the test year revenue requirement.***

Response)

a. As stated in the CONFIDENTIAL attachment to Big Rivers' response to AG 1-52, page 5 of 64, the annual savings from the termination of the CoBank 2012 Line of Credit ("LOC") agreement equal $300,000.

The annual savings are calculated as follows:

CoBank 2012 LOC Commitment Amount	$	50,000,000
Annual Commitment Fee Rate[1]		0.60%
Annual Savings (i.e. Annual CoBank LOC Commitment Fee)	$	300,000

[1] As a result of downgrades to Big Rivers' credit ratings in February 2013, the annual commitment rate for the CoBank 2012 LOC increased from 0.25% to 0.60%, effective February 11, 2013. Please see the attachment to this response for a copy of the notice from CoBank to Big Rivers, dated February

11, 2013, notifying Big Rivers of the change in the Annual Commitment Fee associated with the 2012 LOC. No additional assumptions, data, computations, or electronic spreadsheets were used to calculate the annual savings amount.

b. The test year revenue requirement does reflect $175,000 in savings from the termination of the CoBank 2012 LOC. The difference between the total annual savings of $300,000, calculated in Big Rivers' response to subpart (a), and the savings included in the test year revenue requirement are based on securing a new LOC agreement or amended LOC agreement for $50 million with lower fees. Accordingly, the forecasted test period includes $125,000 for LOC commitment fees associated with this additional $50 million LOC.

Witness) Billie J. Richert

COBANK
P.O. BOX 5110
DENVER, CO 80217

PAGE: 1
PRINT DATE: 2/11/13
PRINT TIME: 12:31:13

N O T I C E

TO: BIG RIVERS ELECTRIC CORPORATION ATTN: DARRIUS VAUGHN
FAX: 12708272558
PHONE: 270-844-6189
RE: BIG RIVERS ELECTRIC CORPORATION/REVOLVER [redacted]
TRANSACTIONS EFFECTIVE 2/11/13

****
PLEASE INCLUDE YOUR COMPANY NAME AND A/C # ON ALL WIRE TRANSFERS TO COBANK.
THIS INFORMATION IS LOCATED ON THIS NOTICE AFTER 'OBI' AND 'BNF'.
****

SPREAD RATE CHANGE

OBLIGATION #:	[redacted]	EFF DATE:	2/11/13
BASE RATE:	3.250000	BALANCE:	.00 USD
SPREAD:	1.150000		
ALL IN RATE:	4.400000		

FACILITY FEE ACCRUAL RATE CHANGE

FEE DESC: 03 FACILITY FEE

EFF DATE:	2/11/13	C/A NUMBER:	[redacted]
NEW ACCRUAL RATE:	.600000	PREVIOUS ACCRUAL RATE:	.600000

FEE DESC: 01 LC COMMISSION FEE

EFF DATE:	2/11/13	C/A NUMBER:	[redacted]
NEW ACCRUAL RATE:	2.150000	PREVIOUS ACCRUAL RATE:	2.150000

ADDITIONAL INFORMATION

*** PRICING CHANGE EFFECTIVE 02/11/2013 ***

VARIABLE SPREAD:	1.15% (NEW)	0.55% (OLD)
REVOLVER UNUSED FEE:	0.60% (NEW)	0.25% (OLD)*
LIBOR SPREAD/LC FEE:	2.15% (NEW)	1.55% (OLD)

PLEASE CONTACT ME WITH ANY QUESTIONS. REGARDS,
REBECKA LAWRISKI
PHONE: (303)740-4369
FAX: (303)740-4100
EMAIL: AgencyBank@COBANK.COM

* Qtrly Unused Commitment Fee:

New ((\$50,000,000 x 0.0060)/360) X90 = \$75,000
Old ((\$50,000,000 x 0.0025)/360) X90 = 31,250
Qtrly Increase/(Decrease) \$43,750

Annual Increase = \$175,000

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2013-00199

Response to the Kentucky Industrial Utility Customers, Inc.'s
Second Request for Information
dated September 16, 2013

September 30, 2013

Item 48) *Please refer to the Company's response to AG 1-52 page 62 of 64.*

a. *Please describe the methodology for the Company's Incentive Pay Award calculations for each year 2012, 2013, and the test year.*

b. *Please provide the amount of Incentive Pay Award expense included in the test year revenue requirement. Provide the underlying calculations of the amount(s). Provide all assumptions, data, computations, including electronic spreadsheets with formulas intact.*

c. *Please identify each employee/position eligible for the Company's Incentive Pay Award, the targets used to determine the amount of the award(s) for each such employee/position, and the amount of the award(s) paid to each employee/position in each year 2012, budgeted for 2013, and projected for the test year.*

d. *Please provide a copy of all Incentive Pay Award materials provided to the Company's BOD in 2011, 2012, and 2013. In addition, please describe all actions taken by the BOD in each of those years to approve the Incentive Pay Award plan, targets, and rates. Provide all documentation of those actions, including all materials provided to the BOD for this purpose and*

each BOD motion or resolution addressing these Incentive Pay Award plan issues.

Response)

a. Big Rivers' incentive plan is based upon budgeted targets/goals that are developed each year and approved by the Board of Directors. No dollars are budgeted for payouts as the plan is designed to be self-funding by producing lower expenses or higher non-member revenues. For 2012 and 2013, plans were developed with the same measurement areas with a maximum payout of 6% for eligible participants. The four measurement areas relate to Financial Performance, Safety, Plant Performance, and Transmission System Reliability. For the Financial Performance target, the company's North Star calculation [(Total Expenses less Non-Member Revenues)/Member kWh)] in the Board-approved budget is the starting point for the minimum payout. The North Star measurement funds the financial measurement and any other measurement that cannot fund itself. In the current plan, the North Star comprises 50% of the total payout and funds approximately 93% of the 6% maximum payout, with the Heat Rate measurement self-funding and EAF

(Equivalent Availability Factor) partially self-funding. To achieve the maximum payout for Financial Performance, higher non-member revenues or lower expenses (or a combination of both) would have to be $13.7 million, with the members receiving $12.3 million and the plan participants receiving $1.4 million. The Safety targets are developed by management. Since it is difficult to quantify the savings related to safety, this measure is funded by North Star. The Plant Performance measure is comprised of EAF and Heat Rate results. The EAF target is established by management using planned outage schedules, historical performance, and unit availability in the production model outputs which are used to develop financial results and the Board-approved annual budgets. This measure can be self-funding as increased generation from a higher EAF increases the off-system sales volumes, but with low market prices in the current plan, this target could only fund 14% of its potential payout, with the remaining 86% being funded by North Star. The Heat Rate target is established based on historical performance, projected fuel quality, and production cost model outputs. This measure is self-funding as a lower heat rate (higher unit efficiency) provides fuel savings. The Transmission System Reliability targets (SAIDI or System

Average Interruption Duration Index) comprise 25% of the potential payout. The targets are developed by using a five-year average of each member system cooperative's transmission system reliability measure. To ensure conservative targets are established, if the five-year average for any individual system is higher than the system-wide average, the system-wide average is adopted for that target. In addition, major outages such as the 2009 ice storm are excluded from the five-year average. To achieve maximum payout for Transmission System Reliability, the company must achieve a 20% improvement in the five-year average. The criteria for determining payments are based on the company's performance in relation to the targets approved each year. Payments are made if performance in a category falls between the minimum and maximum targets, in which case the payout percentage is extrapolated, but only if the company meets its loan covenants. The 2014 incentive plan will not be established and approved by the Board of Directors until the first quarter of 2014.

b. There is no incentive pay included in the test year revenue requirement.

c. The 2012 incentive pay information is attached to this response. For 2013 and the test year, please refer to Big Rivers' response to subpart (a) above.

Incentive pay is not budgeted, and because any pay-out is self-funded, no recovery through rates has been requested. Therefore it is not included in the 2013 Budget or test period.

d. Please see the CONFIDENTIAL attachment to this response.

Witness) Thomas W. Davis

Big Rivers Electric Corporation
Case No. 2013-00199

Attachment for Response for KIUC 2-48 (c)
Statement of Historical Incentive Pay for 2012

Employee #	Gross Pay	Employee #	Gross Pay	Employee #	Gross Pay	Employee #	Gross Pay
1	$ 1,375.77	41	$ 3,115.25	81	$ 3,420.36	121	$ 3,247.55
2	$ 2,092.30	42	$ 3,160.97	82	$ 3,293.16	122	$ 2,989.22
3	$ 1,896.25	43	$ 1,848.44	83	$ 1,852.65	123	$ 3,155.11
4	$ 3,743.01	44	$ 3,257.46	84	$ 2,130.52	124	$ 3,034.08
5	$ 3,126.53	45	$ 1,018.15	85	$ 510.47	125	$ 3,439.07
6	$ 4,540.07	46	$ 3,434.13	86	$ 5,522.49	126	$ 3,529.21
7	$ 3,323.76	47	$ 3,815.05	87	$ 2,687.55	127	$ 3,133.61
8	$ 2,020.72	48	$ 434.42	88	$ 3,429.86	128	$ 1,496.74
9	$ 3,743.01	49	$ 3,480.50	89	$ 1,295.37	129	$ 1,433.78
10	$ 1,801.06	50	$ 2,183.97	90	$ 6,604.81	130	$ 2,742.28
11	$ 3,257.73	51	$ 3,028.88	91	$ 3,781.94	131	$ 1,312.23
12	$ 4,162.17	52	$ 1,686.79	92	$ 3,332.97	132	$ 1,852.18
13	$ 3,827.75	53	$ 6,725.42	93	$ 2,968.57	133	$ 2,038.72
14	$ 3,315.30	54	$ 3,195.01	94	$ 2,622.82	134	$ 3,143.15
15	$ 2,648.19	55	$ 2,502.26	95	$ 1,544.64	135	$ 1,766.87
16	$ 1,306.41	56	$ 3,217.12	96	$ 2,067.70	136	$ 1,334.64
17	$ 2,261.28	57	$ 3,052.04	97	$ 1,481.77	137	$ 2,085.05
18	$ 2,510.16	58	$ 3,427.00	98	$ 3,015.72	138	$ 3,516.74
19	$ 1,464.24	59	$ 3,039.57	99	$ 1,462.03	139	$ 2,538.99
20	$ 1,556.71	60	$ 4,251.59	100	$ 2,798.24	140	$ 1,295.37
21	$ 9,387.31	61	$ 2,745.66	101	$ 2,187.88	141	$ 2,445.38
22	$ 3,335.79	62	$ 3,199.34	102	$ 2,919.14	142	$ 4,130.64
23	$ 755.58	63	$ 3,713.01	103	$ 1,843.64	143	$ 5,188.52
24	$ 1,477.22	64	$ 3,229.02	104	$ 2,515.20	144	$ 1,323.51
25	$ 9,744.54	65	$ 3,543.42	105	$ 2,329.64	145	$ 872.74
26	$ 2,983.21	66	$ 1,586.46	106	$ 1,982.38	146	$ 2,056.94
27	$ 2,773.89	67	$ 3,062.25	107	$ 6,404.44	147	$ 3,280.03
28	$ 1,378.42	68	$ 2,570.91	108	$ 2,990.64	148	$ 2,328.64
29	$ 1,491.22	69	$ 3,726.76	109	$ 3,328.15	149	$ 1,647.44
30	$ 3,157.98	70	$ 1,762.22	110	$ 3,224.91	150	$ 2,564.55
31	$ 3,529.96	71	$ 3,294.59	111	$ 2,829.80	151	$ 2,533.82
32	$ 3,640.59	72	$ 1,475.67	112	$ 3,061.14	152	$ 2,994.55
33	$ 2,596.94	73	$ 3,304.47	113	$ 2,010.33	153	$ 3,176.99
34	$ 1,886.03	74	$ 3,036.13	114	$ 2,925.05	154	$ 2,718.02
35	$ 3,409.94	75	$ 977.86	115	$ 2,151.38	155	$ 3,216.52
36	$ 3,119.59	76	$ 2,683.80	116	$ 1,595.29	156	$ 2,158.62
37	$ 691.82	77	$ 3,279.90	117	$ 1,465.23	157	$ 3,298.54
38	$ 3,412.85	78	$ 5,654.98	118	$ 3,772.35	158	$ 2,618.90
39	$ 2,991.13	79	$ 1,820.89	119	$ 1,667.70	159	$ 1,461.46
40	$ 2,904.39	80	$ 3,143.99	120	$ 3,252.97	160	$ 2,485.67
Subtotal	$ 118,640.82	Subtotal	$ 117,685.35	Subtotal	$ 110,280.91	Subtotal	$ 101,586.07

Big Rivers Electric Corporation
Case No. 2013-00199

Attachment for Response for KIUC 2-48 (c)
Statement of Historical Incentive Pay for 2012

Employee #	Gross Pay	Employee #	Gross Pay	Employee #	Gross Pay	Employee #	Gross Pay
161	$ 1,604.54	201	$ 2,860.64	241	$ 1,300.52		
162	$ 2,252.81	202	$ 2,675.10	242	$ 3,003.21		
163	$ 1,761.76	203	$ 1,333.71	243	$ 3,790.76		
164	$ 4,837.12	204	$ 2,743.48	244	$ 3,488.10		
165	$ 679.48	205	$ 3,110.98	245	$ 2,904.73		
166	$ 3,022.01	206	$ 3,279.03	246	$ 3,253.70		
167	$ 1,545.11	207	$ 3,375.07	247	$ 3,410.62		
168	$ 3,457.69	208	$ 1,676.16	248	$ 1,700.08		
169	$ 3,250.10	209	$ 3,271.24	249	$ 3,227.57		
170	$ 3,264.33	210	$ 2,386.58	250	$ 1,483.69		
171	$ 2,070.59	211	$ 3,273.82	251	$ 4,890.32		
172	$ 1,394.58	212	$ 1,260.76	252	$ 6,529.40		
173	$ 3,318.01	213	$ 2,458.71	253	$ 2,098.98		
174	$ 3,012.28	214	$ 3,855.28				
175	$ 2,178.57	215	$ 4,037.36				
176	$ 3,630.67	216	$ 2,807.04				
177	$ 1,306.30	217	$ 2,119.19				
178	$ 3,056.29	218	$ 442.10				
179	$ 1,140.31	219	$ 2,706.33				
180	$ 2,535.40	220	$ 2,902.14				
181	$ 3,067.19	221	$ 3,424.53				
182	$ 3,440.29	222	$ 4,335.42				
183	$ 1,143.74	223	$ 4,193.81				
184	$ 2,659.73	224	$ 4,594.12				
185	$ 560.98	225	$ 3,412.99				
186	$ 2,788.60	226	$ 2,130.17				
187	$ 2,439.77	227	$ 3,915.90				
188	$ 3,486.33	228	$ 1,301.45				
189	$ 2,792.17	229	$ 2,969.97				
190	$ 1,755.68	230	$ 3,273.81				
191	$ 1,224.16	231	$ 3,075.24				
192	$ 3,302.33	232	$ 1,829.42				
193	$ 656.54	233	$ 3,202.46				
194	$ 3,713.01	234	$ 2,866.11				
195	$ 1,296.31	235	$ 3,664.02				
196	$ 1,295.37	236	$ 3,163.59				
197	$ 2,961.42	237	$ 3,311.43				
198	$ 4,037.32	238	$ 3,644.15				
199	$ 3,254.60	239	$ 3,315.00				
200	$ 3,366.77	240	$ 2,721.61				
Subtotal	$ 98,560.26	Subtotal	$ 116,919.91	Subtotal	$ 41,081.67		
				Grand Total	$ 704,754.99		

Confidential Attachment(s) Produced Separately

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2013-00199

Response to the Kentucky Industrial Utility Customers, Inc.'s
Second Request for Information
dated September 16, 2013

September 30, 2013

Item 49) ***Refer to the Company's response to AG 1-53 page 13 of 56.***

a. ***Please provide a copy of the Big Rivers-KU Amended Interconnection Agreement.***

b. ***Please provide a copy of all other Big Rivers interconnection agreements.***

c. ***Please provide the transfer capacity pursuant to each of the interconnection agreements provided in response to parts (a) and (b) of this question.***

Response)

a. The Amended and Restated Interconnection Agreement among Kentucky Utilities Company, Big Rivers Electric Corporation, and Midcontinent Independent System Operator, Inc. dated July 1, 2013 is attached to this response.

b. The Amended and Restated Interconnection Agreement among Southern Indiana Gas and Electric Company, Big Rivers Electric Corporation, and Midwest Independent Transmission System Operator, Inc. dated December 4, 2012 is attached to this response. The Generator Interconnection Agreement entered into by the Midwest Independent Transmission System Operator, Inc., American Municipal Power, Inc., and Big Rivers Electric Corporation dated

July 6, 2012 is attached in electronic format to this response. The Interconnection Agreement between Louisville Gas and Electric Company and Big Rivers Electric Corporation dated December 21, 1973 is attached to this response. While the Big Rivers interconnection agreements with Southern Illinois Power Cooperative (SIPC), Hoosier Energy, and TVA have not been updated to reflect the MISO membership of Big Rivers, SIPC, and Hoosier Energy, interconnection agreements and a November 20, 2000 clarification agreement are attached to this response.

c. The maximum transfer capabilities based only on the summer ratings of the interconnection facilities follows:

- Five MISO interconnections are rated a combined 2125 MVA. Included are Hoosier Energy (335 MVA), Southern Illinois Power Cooperative (239 MVA), and Vectren (1551 MVA).
- Five existing interconnections with LG&E/KU are rated a combined 2577 MVA. The two future Big Rivers interconnections with the KU Matanzas substation will be rated a combined 1018 MVA.
- Seven interconnections with TVA are rated a combined 1654 MVA.

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2013-00199

Response to the Kentucky Industrial Utility Customers, Inc.'s
Second Request for Information
dated September 16, 2013

September 30, 2013

1 **Witness)** Christopher S. Bradley

AMENDED AND RESTATED INTERCONNECTION AGREEMENT

AMONG

KENTUCKY UTILITIES COMPANY

BIG RIVERS ELECTRIC CORPORATION

And

MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC.

July 1, 2013

Attachment for Response to KIUC 2-49(a)

TABLE OF CONTENTS

AMENDED AND RESTATED INTERCONNECTION AGREEMENT

THIS AMENDED AND RESTATED INTERCONNECTION AGREEMENT (this "Amended Agreement") is made and entered into as of this 1st day of July, 2013, between Kentucky Utilities Company ("KU"), Big Rivers Electric Corporation ("BREC") and the Midcontinent Independent System Operator, Inc., formerly known as Midwest Independent Transmission System Operator, Inc. ("MISO"). KU and BREC are sometimes herein referred to singularly as a "Party" or collectively as the "Parties."

WITNESSETH

WHEREAS, each of the Parties is engaged in the business of generating, acquiring and selling electric capacity and energy and, for such purpose, owns and operates an electric power system including generation, transmission and related facilities; and

WHEREAS, the systems of the Parties now are interconnected, and in the future may be further interconnected; and

WHEREAS, the Parties desire to obtain for themselves the mutual benefits and advantages to be realized by coordinated operation of their systems in the manner and to the extent herein set forth; and

WHEREAS, MISO is a Regional Transmission Organization, and as of December 1, 2010 BREC joined MISO and delegated to MISO functional control of BREC's transmission system for the purpose of providing transmission and interconnection service; and

WHEREAS, on November 1, 2006 the Parties entered into an Interconnection Agreement, which cancelled and superseded all previous IAs between the Parties ("2006 IA"); and

WHEREAS, the Parties desire to amend the 2006 IA in order to reflect BREC's membership in MISO, and to add a new interconnection point between the Parties' respective systems;

NOW, THEREFORE, in consideration of the premises and the mutual agreements herein set forth, the Parties agree as follows:

SECTION 1.0
DEFINITIONS

1.1 Defined Terms. Unless the context otherwise requires, terms used in this Amended Agreement with initial capitalization shall have the meanings ascribed to them below.

1.1.1 "Abnormal Condition" means, in respect of a Transmission Owning-Party's Interconnection Facilities or Transmission System, any condition on such

Interconnection Facilities or Transmission System which is outside normal operating parameters, such that such Interconnection Facilities or Transmission System are operating outside their normal ratings or reasonable operating limits have been exceeded but which has not resulted in an Emergency Condition. An Abnormal Condition may include, but is not limited to, high or low deviations in voltage, frequency, power flow, equipment temperature, equipment pressures, and other equipment and operating parameters.

1.1.2 "Affiliate" means, with respect to any Person, (a) each entity that such Person Controls, (b) each Person that Controls such Person, and (c) each entity that is under common Control with such Person.

1.1.3 "Amended Agreement" means this Amended Agreement, including all exhibits, attachments and appendices hereto that may from time to time exist.

1.1.4 "Assignment" has the meaning provided in Section 13.2 of this Amended Agreement.

1.1.5 "BREC" has the meaning provided in the preamble to this Amended Agreement.

1.1.6 "BREC-Owned Interconnection Facilities" means all those facilities owned, operated, or controlled by or on behalf of BREC which, in conjunction with the KU-Owned Interconnection Facilities, are necessary to effect the transfer of energy to and from the Transmission Systems, as such facilities are identified and described in Facility Schedule(s), and shall include any modifications, additions or upgrades made to those facilities.

1.1.7 "BREC Transmission System" means the transmission facilities (including conductors, circuit breakers, switches, transformers and other associated equipment used to control the transfer of energy from one place to another) owned, operated, or controlled by or on behalf of BREC, including any modifications, additions or upgrades made thereto.

1.1.8 "Control" means the possession, directly or indirectly, through one or more intermediaries, of the following:

(a) (i) in the case of a corporation, fifty percent (50%) or more of the outstanding voting securities thereof; (ii) in the case of a limited liability company, partnership, limited partnership or venture, the right to fifty percent (50%) or more of the distributions therefrom (including liquidating distributions); (iii) in the case of a trust or estate, including a business trust, fifty percent (50%) or more of the beneficial interest therein; and (iv) in the case of any other entity, fifty percent (50%) or more of the economic or beneficial interest therein; and

(b) in the case of any entity, the power or authority, through ownership of

voting securities, by contract or otherwise, to exercise a controlling influence over the management of the entity.

1.1.9 "Default" has the meaning provided in Section 14.4 of this Amended Agreement.

1.1.10 "Defaulting Party" has the meaning provided in Section 14.4 of this Amended Agreement.

1.1.11 "Dispute" has the meaning provided in Section 19.3.1 of this Amended Agreement.

1.1.12 "Dispute Notice" has the meaning provided in Section 19.3.2 of this Amended Agreement.

1.1.13 "Emergency Condition" means a condition or situation that a Party reasonably determines is imminently likely (a) to endanger life or property or (b) to cause a material adverse effect on the security of, or damage to, its Transmission System, Interconnection Facilities or the electric systems of others to which its Transmission System is directly connected.

1.1.14 "Facility Schedule" means the terms and conditions agreed to by the Parties attached hereto as Appendix II and incorporated herein by reference, which specify the responsibilities of the Parties for the ownership, operation and maintenance applicable to each Point of Interconnection.

1.1.15 "FERC" has the meaning provided in the recitals to this Amended Agreement.

1.1.16 "Force Majeure" means any cause beyond the reasonable control of the Party affected, including acts of God, flood, drought, earthquake, storm, ice, fire, lightning, epidemic, war, acts of public enemy, terrorist acts, sabotage, insurrection, riot, civil disturbance or disobedience, labor disputes, labor or material shortage, explosions, breakage or accident to machinery or equipment (which is caused by an event of Force Majeure), orders, regulations or restrictions imposed by governmental, military or lawfully established civilian authorities, provided that "Force Majeure" shall not include any act of negligence or intentional wrongdoing by such Party.

1.1.17 "Good Utility Practice" means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision is made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. "Good Utility Practice" is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather, intended to include acceptable practices, methods or acts generally accepted in the region, but

are not necessarily codified.

1.1.18 "Indemnified Party" has the meaning provided in Section 15.1 of this Amended Agreement.

1.1.19 "Indemnifying Party" has the meaning provided in Section 15.1 of this Amended Agreement.

1.1.20 "Initial Term" has the meaning provided in Section 14.1 of this Amended Agreement.

1.1.21 "Interconnection Facilities" means the BREC-Owned Interconnection Facilities and the KU-Owned Interconnection Facilities.

1.1.22 "ITO" means the Person that performs the function of the "Independent Transmission Organization" under the OATT.

1.1.23 "KU" has the meaning provided in the preamble to this Amended Agreement.

1.1.24 "KU-Owned Interconnection Facilities" means all those facilities owned, operated or controlled by or on behalf of KU which, in conjunction with the BREC-Owned Interconnection Facilities, are necessary to effect the transfer of energy to and from the Transmission Systems, as such facilities are identified and described in Facility Schedule(s), and shall include any modifications, additions or upgrades made to those facilities.

1.1.25 "KU Transmission System" means the transmission facilities (including conductors, circuit breakers, switches, transformers and other associated equipment used to control the transfer of energy from one place to another) owned, operated or controlled by or on behalf of KU, including any modifications, additions or upgrades thereto.

1.1.26 "KU" has the meaning provided in the preamble to this Amended Agreement.

1.1.27 "LG&E" means Louisville Gas and Electric Company, KU's affiliate.

1.1.28 "MISO" has the meaning provided in the preamble to this Amended Agreement.

1.1.29 "OATT" means LG&E's and KU's joint Open Access Transmission Tariff, as accepted for filing by FERC, as the same may be in effect from time to time.

1.1.30 "Operating Committee" has the meaning provided in Section 3.2 of this Amended Agreement.

1.1.31 "Parent" means, with respect to any Person, the Person that Controls such Person and that is not itself Controlled by any other Person.

1.1.32 "Party" and "Parties" has the meaning provided in the preamble to this Amended Agreement.

1.1.33 "Person" means an individual, a corporation, a partnership, a limited liability company, an association, a joint-stock company, a trust, an unincorporated organization or any governmental or political subdivision thereof.

1.1.34 "Point of Interconnection" and "Points of Interconnection" shall mean the point or points at which the Transmission Systems are connected as specified in Appendix I attached to this Amended Agreement, as the same may be added, deleted or otherwise changed from time to time in accordance with this Amended Agreement.

1.1.35 "RC" means, in the case of BREC, its Reliability Coordinator, and, in the case of KU, the Person that performs the functions of the "Reliability Coordinator" under the OATT.

1.1.36 "Renewal Terms" has the meaning provided in Section 14.1 of this Amended Agreement.

1.1.37 "Representatives" means, in respect of a Party, such Party's Parent, subsidiaries, Affiliates, members, managers, shareholders, directors, officers, employees, agents, successors or assigns.

1.1.38 "RUS" means the Rural Utilities Service of the United States Department of Agriculture.

1.1.39 "SERC" means the SERC Reliability Corporation, a regional reliability organization.

1.1.40 "System Operator" means, in respect of each Party, the operation personnel in the control center for such Party that are responsible for the real time monitoring and operation of such Party's Transmission System.

1.1.41 "Tariff" means the Open Access Transmission, Energy and Operating Reserve Markets Tariff filed by MISO with the FERC and as it may be amended from time to time, or any successor tariff, as to its authority over the BREC Transmission System.

1.1.42 "Transmission Service" means the service obtained by a Party under the other Party's Open Access Transmission Tariff, or, if no such Open Access Transmission Tariff exists, under bilateral agreement, to transmit capacity and energy over the other Party's Transmission System.

1.1.43 "Transmission Systems" means the BREC Transmission System and the KU

Transmission System.

1.2. Interpretation. Except as otherwise expressly provided herein, the rules of interpretation and construction set forth below shall apply to this Amended Agreement:

1.2.1 all defined terms in the singular shall have the same meaning when used in the plural and vice versa;

1.2.2 the words "hereof," "herein" and "hereto" and similar words refer to this entire Amended Agreement and not to any particular Section, Appendix or any other subdivision of this Amended Agreement;

1.2.3 the capitalized terms "Section" and "Appendix" refer, respectively, to sections of, or appendices to, this Amended Agreement;

1.2.4 reference to any law, statute, rule, regulation, tariff, notification or statutory provision shall be construed as a reference to such law, statute, rule, regulation, tariff, notification or statutory provision as it applies to this Amended Agreement and the Parties and as it may have been, or may from time to time be, amended, modified or re-enacted;

1.2.5 the words "includes" and "including" and similar phrases shall mean "including without limitation";

1.2.6 the captions, section numbers and headings in this Amended Agreement are included for convenience of reference only and shall not in any way affect the meaning or interpretation of this Amended Agreement;

1.2.7 reference to a particular Party or Person includes such Party's or Person's successors and assigns to the extent not prohibited by this Amended Agreement.

SECTION 2.0
POINTS OF INTERCONNECTION, CONTINUING OBLIGATIONS AND RESPONSIBILITIES

2.1 Points of Interconnection. The Points of Interconnection between the Parties are specified in Appendix I, and shall be operated and maintained in accordance with the terms and conditions in this Amended Agreement, including the Facility Schedule(s) listed in Appendix II attached to this Amended Agreement, which are incorporated by reference herein.

2.2 Service Conditions.

2.2.1 The Points of Interconnection, other than those designated as normally-open on Appendix I, shall be operated in continuous synchronization through such interconnection, except in cases of interruption of such synchronous operation due

to (a) mutually agreed upon maintenance, (b) directives from one or both RCs in accordance with applicable North American Electric Reliability Corporation standards or (c) Force Majeure. If synchronous operation is interrupted, the Parties shall cooperate so as to remove the cause of such interruption as soon as commercially practicable, consistent with Good Utility Practice.

2.2.2 All Points of Interconnection shall conform to such operating guidelines as the Operating Committee shall from time to time agree upon.

2.3 Additional Services.

2.3.1 This Amended Agreement is applicable only to the physical interconnection of the Parties' Transmission Systems and Interconnection Facilities at the Points of Interconnection and does not obligate either Party to receive or provide any service. Other services provided by one Party to the other Party shall be governed by such other agreements as the Parties may enter into from time to time.

2.3.2 Each Party is responsible for making necessary arrangements to receive any services that it may desire from another party (including the other Party) or cannot otherwise provide itself. In furtherance of the foregoing, a Party whose load or contractual load is isolated onto the other Party's Transmission System shall be responsible for making arrangements to obtain Transmission Service with respect to such load.

2.3.3 Points of Interconnection designated as normally-open on Appendix I may be closed to effect a transfer of one Party's load to the other Party's Transmission System if necessary to address a contingency on the Transmission System of the Party to which such load is ordinarily connected. As soon as practical after such normally open interconnection is closed, the Transmission System of the transferring Party will be sectionalized and operated in a radial configuration that will not jeopardize the relay protection for any energized line.

2.3.3.1 For planned maintenance outages, the Party wishing to serve load from the other Party's Transmission System will make prior arrangements with the other Party to purchase Transmission Service for the delivery of the estimated energy amounts to be transferred. After Transmission Service has been obtained, the normally-open Point of Interconnection may be closed with the approval of the other Party's System Operator to effect a transfer of load and then sectionalize the Transmission System pursuant to Section 2.3.3.

2.3.3.2 For unplanned outages, the Party experiencing the outage will notify the other Party as promptly as is reasonably possible under the circumstances. With the approval of other Party's System Operator, the normally-open Point(s) of Interconnection may be closed to effect a transfer of load and then sectionalize the Transmission System pursuant to Section 2.3.3. Transmission Service will then be properly requested by the Party experiencing the outage.

2.3.4. No Party shall be obligated to deliver reactive power for the benefit of the other Party. No Party shall be obligated to receive reactive power when to do so might introduce objectionable operating conditions on its system. Subject to the foregoing, the Parties, through the Operating Committee, shall establish from time to time (a) voltage levels to be maintained and (b) operating procedures for establishing and maintaining an equitable distribution of reactive power.

2.4 Safety.

2.4.1 Responsibility for Safety of Employees, Etc. Except as otherwise provided in Section 15.0, each Party shall be solely responsible for and assume all liability for the safety and supervision of its respective employees, agents, representatives and subcontractors.

2.4.2 Compliance with Applicable Laws. All work performed hereunder by any Party, will be performed in accordance with Good Utility Practice and all applicable laws, rules and regulations pertaining to the safety of persons or property.

SECTION 3.0
OPERATION AND MAINTENANCE; OPERATING COMMITTEE

3.1 Operation and Maintenance. Unless otherwise provided by the Facility Schedules in Appendix II, each Party shall, at its own risk and expense (a) use commercially reasonable efforts to operate and maintain the facilities (including its Transmission System and Interconnection Facilities) and equipment that are owned, controlled or operated by it or on its behalf, or that may be owned, controlled or operated by it or on its behalf, and (b) design and install equipment and facilities (including all apparatus and necessary protective devices) on its side of each Point of Interconnection, in each case, in accordance with Good Utility Practice so as to reasonably minimize the likelihood of a disturbance originating on its Transmission System or Interconnection Facilities from affecting or impairing the other Party's Transmission System or Interconnection Facilities or other transmission systems to which it is interconnected. With respect to BREC, such design and installation will be carried out in coordination with MISO as required by the terms of its Tariff.

3.2 Operating Committee.

3.2.1 Representatives. The Parties shall establish a committee of authorized representatives to be known as the Operating Committee. Each Party shall designate in writing delivered to the other Party, the person who is to act as its representative on the Operating Committee (and the person or persons who may

serve as an alternate or alternates whenever such representative is unable to act). Such representative and alternate(s) shall be a person familiar with the Transmission System and Interconnection Facilities of the Party he or she represents, and each shall be fully authorized to cooperate on behalf of the Party he or she represents in performing the functions delegated to the Operating Committee.

3.2.2 Authority of the Operating Committee. The Operating Committee shall be authorized to address the following:

3.2.2.1 Coordination of maintenance of the Transmission Systems and the Interconnection Facilities but only to the extent such maintenance is not subject to control by MISO, the ITO and/or RCs.

3.2.2.2 Control of time, frequency, energy flow, power factor, voltage and other similar matters bearing upon the satisfactory synchronous operation of the Transmission Systems and Interconnection Facilities.

3.2.2.3 Establishment of criteria, rules and standards for the testing and calibration of metering equipment required pursuant to Section 5.0.

3.2.2.4 Monitoring and confirming the Parties' compliance with Section 2.3.4.

3.2.2.5 Such other functions not specifically provided for herein which the Parties mutually agree upon.

3.2.3 No Authority to Amend. The Operating Committee shall not have authority to modify any of the terms or conditions of this Amended Agreement. The Operating Committee may, to the extent appropriate, solicit input from MISO, the ITO and/or the RC, and in any event shall perform its functions consistent with any directives of MISO, the ITO and/or the RC.

3.2.4 Disputes. If the Operating Committee is unable to take action on any matter to be acted upon by it under this Amended Agreement because of a dispute between the representatives as to such matter, then the matter shall be resolved in accordance with Section 19.3.

SECTION 4.0
RIGHTS OF ACCESS; EQUIPMENT INSTALLATION AND REMOVAL

4.1 Rights of Access. Each Party shall permit duly authorized representatives and employees of the other Party to enter upon its premises for the purpose of (a) inspecting, testing, repairing, renewing or exchanging any of the equipment owned by such other Party

located on its premises or (b) performing any work necessary in the performance of this Amended Agreement, in each case, upon reasonable notice to the Party, at reasonable times and in compliance with Good Utility Practice and the Party's reasonable rules and regulations.

4.2 Equipment Installation. Each Party shall permit duly authorized representatives and employees of the other Party to install, maintain and operate on its premises the necessary equipment, apparatus and devices required for the performance of this Amended Agreement. Any such installation, maintenance and operation to be performed, except in Emergency Conditions, shall be performed after reasonable notice of the schedule of activity is submitted to the Party, at reasonable times and in compliance with Good Utility Practice and the Party's reasonable rules and regulations. Any equipment, apparatus and devices installed pursuant to this Section 4.2 shall be clearly marked by the Party with appropriate ownership identification.

4.3 Equipment Removal. Any and all equipment, apparatus, devices and facilities placed or installed, or caused to be placed or installed by one Party on, or in, the premises of the other Party, shall be and remain the property of the Party owning and installing such equipment, apparatus, devices or facilities, regardless of the mode and manner of annexation or attachment to real property, unless mutually agreed otherwise by the Parties. Upon the termination of any Point of Interconnection in accordance with this Amended Agreement, the Party owning and installing such equipment, apparatus, devices or facilities at the Point of Interconnection shall have the right (a) to sell such equipment, apparatus, devices or facilities to the other Party if the other Party wishes to purchase such equipment, apparatus, devices or facilities, or (b) enter the premises of the other Party and remove, at the owning Party's cost, such equipment, apparatus, devices or facilities that are salvageable upon reasonable notice to the other Party, at reasonable times and in compliance with Good Utility Practice and the other Party's reasonable rules and regulations.

SECTION 5.0
DELIVERY AND METERING

5.1 Delivery. All energy delivered to or flowing through a Point of Interconnection shall be in the form of three-phase, sixty (60) hertz alternating current.

5.2 Testing and Sealing of Meters. All metering equipment installed in accordance with this Amended Agreement shall be tested and calibrated, and its accuracy of registration maintained, by its owner in accordance with its owner's established criteria, rules and standards until such time as the Operating Committee establishes its own criteria, rules and standards. All meters shall be sealed, and such seals may be broken only by its owner on such occasions when the meters are to be inspected, tested, calibrated or adjusted. Each Party shall comply with any reasonable request of the other Party concerning (a) the testing, calibration and sealing of meters, (b) the presence of a representative of the other Party when the seals are broken and tests are made, and (c) other matters affecting interchange measurements. If any Party believes that there has

been a meter inaccuracy, failure or stoppage, that Party shall immediately notify the other Party.

5.3 Meter Inaccuracy. If, at any time, any metering equipment is found to be inaccurate by a margin of greater than that allowed under any applicable criteria, rules or standards of MISO, SERC (or any replacement entity to which either Party becomes subject to in future) or the Operating Committee or any other applicable mandatory criteria, rules or standards, each Party shall cause its metering equipment to be made accurate or replaced; provided that, in the event of a conflict between any MISO, SERC, Operating Committee or other applicable mandatory criteria, rules and standards, the Operating Committee criteria, rules and standards shall govern. Meter readings for the period of inaccuracy shall be adjusted, for accounting purposes, by correcting all measurements made by the inaccurate meter for (a) the actual period during which inaccurate measurements were made, if the period can be determined, or if not, (b) the period immediately preceding the test of the metering equipment equal to one-half the time from the date of the last previous test of the metering equipment; provided that the estimated period covered by the correction under this Section 5.3(b) shall not exceed six (6) months.

5.4 Losses. If a metering point and the applicable Point of Interconnection are not at the same location, the metering equipment shall record delivery of energy in a manner that accounts for losses occurring between the metering point and the applicable Point of Interconnection. Losses occurring between the metering point and the applicable Point of Interconnection shall be allocated pursuant to the applicable tariff or other applicable agreement then in effect between the Parties.

5.5 Communications with Meters. Access to the meters discussed in Section 5.0 shall be permitted in accordance with the provisions of Section 4.1. Both Parties will be permitted to communicate electronically to the meters discussed in Section 5.0 in accordance with the provisions of Section 4.2.

SECTION 6.0
RECORDS AND BILLING

6.1 Maintenance of Books and Records. Each Party shall maintain, in accordance with normal utility accounting procedures, complete books and records of its respective costs and expenses incurred in connection with any upgrades to or new Points of Interconnection pursuant to Section 7.0. Each Party will make available to the other Party for inspection, through its employees, agents or independent public accountant, all records used to establish charges, if any, in accordance with this Amended Agreement. All inspections will be performed at the inspecting Party's own expense during normal business hours in the offices of the Party in possession of such records, upon reasonable notice.

6.2 Duration. All books, records and other pertinent data associated with this Amended Agreement shall be maintained for the most recent historical four (4) years during the term of this Amended Agreement and for two (2) years following the expiration or early

termination of this Amended Agreement.

6.3 Billing. If a Party is owed a payment or other amount under this Amended Agreement, then such Party shall invoice the other Party for such payment or amount and the other Party shall pay the undisputed amount of such payment or amount, within twenty (20) days of the date of the invoice. Interest on unpaid amounts shall accrue at the applicable prime rate for each calendar month, or part thereof, published in the Federal Reserve Statistical Release H.15, or its successor publication, rounded to the nearest one-hundredths of one percent (.01%), but in no event more than the maximum allowed by applicable law, and shall accrue and be payable from the date due until the date upon which payment is made. Unless otherwise agreed upon, a calendar month shall be the standard monthly period for the purpose of settlements under this Amended Agreement.

6.4 Billing Disputes. In the event a Party wishes to contest a portion of an invoiced amount, such Party shall pay the portion not contested, and interest shall accrue pursuant to Section 6.3 on the unpaid portion while resolution of the contested amounts is pending, from the date such payment was due until the date on which payment is made, and shall apply only to that portion of the disputed amount which is determined to be payable.

SECTION 7.0
REQUESTED UPGRADES AND ADDITIONAL POINTS OF INTERCONNECTION

7.1 Requested Upgrades or Additional Point of Interconnection. If a Party believes that upgrades to one or more Points of Interconnection are necessary or that one or more additional Points of Interconnection are necessary, then such Party shall promptly notify the other Party in writing, including, as appropriate, a description of the Point(s) of Interconnection which the Party desires to upgrade and the reasons why, the desired location and designation of any additional Point(s) of Interconnection, the desired in-service date for the requested upgrade(s) or additional Point(s) of Interconnection, and any other information relevant to the requested upgrade or additional Point(s) of Interconnection, including any relevant studies or analyses. The Parties shall meet to discuss the requested upgrades or additional Point(s) of Interconnection, and thereafter, shall cooperate to study or cause to be studied the requested upgrades or additional Point(s) of Interconnection in accordance with their applicable interconnection procedures, and consistent with any directives from the ITO or the RCs.

7.2 Facility Schedules. If the Parties mutually agree to upgrade a Point of Interconnection or to add a Point of Interconnection pursuant to Section 7.1, then the Parties shall amend Appendix I and the appropriate Facility Schedule or add a new Facility Schedule to Appendix II, which shall be separately executed and attached hereto, and the upgrade or additional Point of Interconnection shall be effective as of the date such amendment(s) are accepted for filing by FERC.

7.3 No Waiver. Nothing in this Section 7.0 shall waive or limit in any way, a Party's rights under applicable provisions of the Federal Power Act and the FERC's rules and regulations promulgated thereunder to request an upgrade to a Point of Interconnection or

add a Point of Interconnection.

SECTION 8.0
INFORMATION AND OTHER REQUIREMENTS

Upon request, a Party shall promptly provide to the other Party such engineering information, including load forecasts and generation data, regarding plans, practices and conditions of operation and equipment as is reasonably necessary to enable the other Party to adequately plan, design and install, for practical and efficient operation, the Transmission Systems and Interconnection Facilities in accordance with this Amended Agreement.

SECTION 9.0
EMERGENCY CONDITION

9.1 Notification. If a Party becomes aware of an Abnormal Condition or Emergency Condition affecting its Transmission System or Interconnection Facilities which may reasonably be expected to damage or adversely to affect the security or operations of the other Party's Transmission System and Interconnection Facilities, then the Party shall provide prompt notification by telephone thereof to the other Party's System Operator. Such notifications shall indicate, to the extent known, the expected damage to or effect of the Abnormal Condition or Emergency Condition on the security or operation of, the other Party's Transmission System and Interconnection Facilities, its expected duration and any recommended corrective action to be taken.

9.2 Actions By the Parties.

9.2.1 If a Party reasonably determines (or is informed by MISO and/or the RC) that an Abnormal Condition or Emergency Condition exists, then it may take such action(s), consistent with Good Utility Practice, as may be reasonable to prevent, avoid or mitigate (a) any danger to life or property or (b) any material adverse effect to the security of, or damage to its Transmission System, Interconnection Facilities or the electric systems of others to which its Transmission System is directly connected, in each case, that is caused by such Abnormal Condition or Emergency Condition.

9.2.2 If a Party believes in its good faith judgment that action taken pursuant to Section 9.2.1 includes the temporary isolation of the other Party's Interconnection Facilities, then the Party shall use commercially reasonable efforts, consistent with Good Utility Practice, to notify the other Party prior to such isolation.

9.3 Actions by a Party. In addition to any rights provided for in this Section 9.0, a Party may exercise any of its rights under the Tariff, OATT, or applicable open access transmission tariff with respect to an emergency condition.

SECTION 10.0
FORCE MAJEURE

10.1 No Breach or Default. No Party shall be considered in breach or Default of its obligations under this Amended Agreement if and to the extent that such Party is prevented from performing such obligations by reason of Force Majeure.

10.2 Notice. If a Party is prevented from performing its obligations under this Amended Agreement because of Force Majeure, it shall so notify the other Party within a reasonable time after the occurrence of such Force Majeure.

10.3 Duration of Force Majeure. A Party shall be excused from whatever performance is affected by Force Majeure only for the duration of the Force Majeure and only for so long as such Party uses commercially reasonable efforts to attempt to alleviate or remove the cause of its failure to perform, consistent with Good Utility Practice, provided that no Party shall be obligated to appeal from any administrative or judicial ruling, or to agree to any settlement of any strike or labor disturbance, which, in the affected Party's opinion, may be inadvisable or detrimental.

10.4. Obligation to Make Payments. Notwithstanding any provision in this Amended Agreement to the contrary, no Party shall be relieved from its obligation to make payments under this Amended Agreement due to Force Majeure.

SECTION 11.0
WAIVERS

Any waiver at any time by any Party of its rights with respect to a default under this Amended Agreement, or with respect to any other matter arising in connection with this Amended Agreement, shall not be deemed a waiver with respect to any subsequent default or matter. Any delay short of the statutory period of limitation in asserting or enforcing any right shall not be deemed a waiver of such right.

SECTION 12.0
NOTICES

Unless otherwise expressly provided for in this Amended Agreement, all notices and communications pursuant to this Amended Agreement between the Parties and/or MISO shall be: (a) made in writing, by facsimile or by email; (b) delivered to the other Party at its address, facsimile number or email address listed below; and (c) deemed to have been duly delivered: (i) upon personal delivery thereof, including by overnight mail or next Business Day or courier service; (ii) in the case of notice by United States mail, if sent by certified or registered mail, postage prepaid, return receipt requested, upon receipt thereof; (iii) in the case of notice by facsimile, upon transmission thereof (if successful transmission is confirmed by the facsimile machine), provided that in addition to such

transmission a confirmation copy of the notice is also provided promptly by either of the methods set forth in clause (i) or (ii) above; or (iv) in the case of email, upon transmission thereof, provided that in addition to such transmission a confirmation copy of the notice is also provided by either of the methods set forth in clause (i) or (ii) above, and provided that the sender does not receive any message indicating that the email message was not delivered to the persons to which notices are to be delivered pursuant to this Amended Agreement. All communications pursuant to this Amended Agreement shall be addressed as provided below, or to such other address as any Party may designate by written notice to the other Party given in accordance with this Section 12.0:

If to BREC:

Big Rivers Electric Corporation
201 Third Street
Henderson, Kentucky 42420
Attn: VP System Operations

Telephone: (270) 827-2561
Email: david.crockett@bigrivers.com

If to KU:

LG&E/KU Services, Inc.
220 West Main Street
PO Box 32010
Louisville, Kentucky 40202
Attn: VP, Transmission

Telephone: (502) 627-2135
Email: tom.jessee@lge-ku.com

If to MISO:

MISO
Attn: Director, Transmission Access Planning
P.O. Box 4202
Carmel, IN 46082-4202

For overnight deliveries:
720 City Center Drive
Carmel, IN 46032

Telephone: (317) 249-5496
Facsimile:
Email: elaverty@misoenergy.org

SECTION 13.0
SUCCESSORS, ASSIGNS, AND THIRD PARTY BENEFICIARIES

13.1 Binding On Parties. Successors, and Assigns. This Amended Agreement shall be binding upon and inure to the benefit of the Parties and their permitted successors and assigns. No person shall have any rights, benefits or interests, direct or indirect, arising from this Amended Agreement except the Parties, their permitted successors and assigns. The Parties expressly disclaim any intent to create any rights in any Person as a third party beneficiary of this Amended Agreement.

13.2 Assignment. Except as provided below, no Party may assign, transfer, sell, convey or otherwise dispose of in any manner, directly or indirectly (collectively, "Assignment"), all or any portion of this Amended Agreement or its rights, benefits, duties, obligations and liabilities under this Amended Agreement, without the prior written consent of the other Party, which consent shall not be unreasonably withheld. Any Assignment made without such prior written consent shall be null and void; provided, however, that such written consent shall not be required by a Party in connection with an Assignment to (a) a successor entity to which all or substantially all of the business and assets of such Party are transferred; or (b) an Affiliate or wholly-owned direct or indirect subsidiary of the Parent of such Party, provided that each such assignee pursuant to paragraph (a) and (b) above assumes in writing all rights, benefits, duties, obligations and liabilities of the assigning Party arising under this Amended Agreement, provided further that each such Affiliate pursuant to paragraph (b) above is capable of assuming and performing its obligations hereunder. Notwithstanding the foregoing, nothing in this Amended Agreement shall limit in any way any Party's rights to intervene in and/or protest any filing made by any other Party with the FERC or any other government authority in regards to the sale, merger or transfer of all or substantially all of the business and assets of a Party, including its Transmission System and Interconnection Facilities.

13.3 Assigning Party to Remain Responsible. Any Assignments authorized as provided for in Section 13.2 will not operate to relieve the Assigning Party of any of its duties, obligations or liabilities arising under this Amended Agreement up to or after the date of such Assignment unless and only to the extent the other Party consents in writing, which consent shall not be unreasonably withheld.

SECTION 14.0
TERM AND TERMINATION OF AGREEMENT; DEFAULT

14.1 Term. This Amended Agreement shall be effective as of the date hereof, subject to its approval or acceptance for filing by the FERC and RUS, and shall continue in effect until the date falling on the tenth anniversary of the date hereof (the "Initial Term"), and, thereafter, for successive twelve (12) month periods ("Renewal Terms"). Either Party may terminate this Amended Agreement after the Initial Term by providing to the other

Party at least twelve (12) month's advance written notice of its intent to terminate this Amended Agreement, in which case this Amended Agreement shall terminate at the end of such twelve (12) month notice period without regard to the expiration of any Renewal Term. Notwithstanding the above, this Amended Agreement may be terminated earlier (a) if the Parties mutually agree or (b) as otherwise expressly provided for in this Amended Agreement. In the event of early termination the Parties shall provide notice to MISO. Notwithstanding anything to the contrary contained in this Section 14.1, no termination shall become effective until the Parties have complied with all laws and regulations applicable to such termination, including the filing with FERC of a notice of termination of this Amended Agreement, which notice has been accepted for filing by FERC.

14.2 Effect of Expiration or Termination of Agreement on Liabilities and Obligations. Expiration or early termination of this Amended Agreement shall not relieve any Party of its duties, obligations and liabilities arising hereunder prior to the date such expiration or early termination becomes effective or of its duties, obligations, or liabilities that survive termination by operation of the express terms of this Amended Agreement or by operation of law.

14.3 Effectiveness of Certain Provisions After Expiration or Termination of Agreement. The applicable provisions of this Amended Agreement (including Sections 15, 16 and 19) will continue in effect after expiration or early termination hereof to the extent necessary to provide for final billings, if any, and the determination and enforcement of liability and indemnification obligations arising from acts or events that occurred while this Amended Agreement was in effect.

14.4 Default. A Party shall be in default under this Amended Agreement (each, a "Default", and such party a "Defaulting Party") if:

14.4.1 the Defaulting Party fails to perform any of its material duties or obligations under this Amended Agreement, which failure continues for thirty (30) days after written notice thereof from the other Party; provided that if such failure (other than the failure to make payment of any amounts due and payable hereunder) is not capable of being cured within such thirty (30)-day period with the exercise of reasonable diligence, then such cure period shall be extended for an additional reasonable period of time, not to exceed thirty (30) days, so long as the Defaulting Party is exercising reasonable diligence to cure such failure;

14.4.2 the Defaulting Party: (a) applies for or consent to the appointment of a trustee, receiver, liquidator, custodian, or the like for itself or its properties, (b) is unable, or admits in writing its inability, to pay its debts as they mature, (c) makes a general assignment for the benefit of its creditors, (d) commences a voluntary case under a chapter of the Bankruptcy Reform Act of 1978 or other applicable legal requirement, or files a petition, answer or consent seeking reorganization or an answer admitting the material allegations of a petition filed against it in any bankruptcy, reorganization, or insolvency proceeding, or fails to controvert in a

timely and appropriate manner (or acquiesce in writing to) any such petition, or (e) takes any corporate or partnership action for the purposes of effecting any of the foregoing; or

14.4.3 a proceeding or case is commenced, without the application or consent of the Defaulting Party against which the proceeding or case is commenced, in any court of competent jurisdiction, seeking: (a) its liquidation, reorganization of its debts, dissolution or winding-up or the composition or readjustment of its debts; (b) the appointment of a receiver, custodian, liquidator or the like of the Defaulting Party or of all or any substantial part of its assets; or (c) similar relief in respect of the Defaulting Party under any law relating to bankruptcy, insolvency, reorganization of its debts, winding-up, composition or adjustment of debt

14.5 Remedies of Parties Upon Default. Upon a Default by a Defaulting Party, the non-defaulting Party may, at its option, (a) take action to terminate this Amended Agreement by providing written notice of termination to the Defaulting Party and MISO and requesting the FERC to terminate this Amended Agreement, provided that any such termination shall not take effect until the FERC authorizes such requested termination, and/or (b) take any other action at law or in equity as may be permitted under this Amended Agreement or available to such party under applicable law to enforce the performance or observance of any rights, remedies, duties, obligations or liabilities under this Amended Agreement.

14.6 Remedies Cumulative. No remedy conferred by any of the provisions of this Amended Agreement is intended to be exclusive of any other remedy now or hereafter existing at law or in equity or by statute or otherwise. The election of any one or more remedies shall not constitute a waiver of the right to pursue any other available remedies.

SECTION 15.0
INDEMNITY

15.1 Indemnity. Each Party (the "Indemnifying Party") shall, at its own cost and expense, defend, indemnify and hold harmless the other Party and its Representatives (each an "Indemnified Party") from and against any and all loss, liability, damages, claims, demands, actions, causes of action, costs or expenses, including damage and liability for bodily injury to or death of persons, or damage to property (including reasonable attorneys' fees, legal costs and expenses) to extent arising out of, in connection with or resulting from: (a) the Indemnifying Party's breach of its obligations under this Amended Agreement; or (b) the negligence or willful misconduct of the Indemnifying Party or any of its Representatives, except, in each case, to the extent to which such loss, liability, damages, claims, demands, actions, causes of action, costs or expenses are caused by the negligence or willful misconduct of the Indemnified Party.

15.2 Cooperation Regarding Claims. If any Indemnified Party receives notice or has knowledge of any claim that may result in a claim for indemnification by such Indemnified Party against the Indemnifying Party pursuant to Section 15.1, such Indemnified Party shall promptly give the Indemnifying Party notice of such claim,

including a reasonably detailed description of the facts and circumstances relating to such claim, a complete copy of all notices, pleadings and other papers related thereto, and in reasonable detail the basis for its claim for indemnification with respect thereto. Failure to promptly give such notice or to provide such information and documents shall not relieve the Indemnifying Party from the obligation hereunder to respond to or defend the Indemnified Party against such claim unless such failure shall materially diminish the ability of the Indemnifying Party to respond to or to defend the Indemnified Party against such claim. The Indemnifying Party, upon its acknowledgment in writing of its obligation to indemnify the Indemnified Party in accordance with this Section 15.0, shall be entitled to assume the defense or to represent the interest of the Indemnified Party with respect to such claim, which shall include the right to select and direct legal counsel and other consultants, appear in proceedings on behalf of such Indemnified Party and to propose, accept or reject offers of settlement, all at its sole cost. If and to the extent that any such settlement is reasonably likely to involve injunctive, equitable or prospective relief or materially and adversely affect the Indemnified Party's business or operations other than as a result of money damages or other money payments, then such settlement will be subject to the reasonable approval of the Indemnified Party. Nothing herein shall prevent an Indemnified Party from retaining its own legal counsel and other consultants and participating in its own defense at its own cost and expense.

15.3 Indemnified Party. If an Indemnified Party is entitled to indemnification under this Section 15.0 as a result of a claim by a third party, and the Indemnifying Party fails to assume the defense of such claim, such Indemnified Party may at the expense of the Indemnifying Party contest, settle, consent to the entry of any judgment with respect to, or pay in full, such claim.

SECTION 16.0
LIMITATION OF LIABILITY

16.1 Responsibility of the Parties.

16.1.1 Except as otherwise provided in Sections 14.0 and 15.0, neither Party shall be responsible for or liable to the other Party or any of its Affiliates or any of their respective Representatives for injury to any person or damage to any property, equipment or facilities owned by the other Party or its Affiliates (including its Transmission System and Interconnection Facilities) regardless of who brings the claim and regardless of who caused the injury or damage (including injury or damage arising, occurring or resulting from, in any manner, the receiving, transmission, control, use, application or distribution by the other Party of electricity), and such other Party will not seek recovery or reimbursement from the Party for such injury or damage. The obligations under this Section 16.1 are not limited in any way by any limitation on any Party's insurance.

16.1.2 Notwithstanding any provision to the contrary contained in this Amended Agreement, no Party shall be liable to any other Party for any action it takes in responding to an Emergency Condition so long as such action is made in good faith and consistent with Good Utility Practice.

16.1.3 Unless otherwise provided for in the Facility Schedules or agreed to in writing by the Parties, neither Party assumes any responsibility, in whole or in part, with respect to the construction, installation, maintenance or operation of the other Party's Transmission System, Interconnection Facilities or other facilities or equipment of any kind which are owned, controlled or operated by or on behalf of the other Party on the other Party's side of a Point of Interconnection.

16.2 No Consequential Damages. Neither Party nor any of its Representatives shall be liable under this Amended Agreement, whether in contract, tort (including negligence and strict liability) or otherwise, to the other Party or any of its Representatives for incidental, punitive, special, indirect, multiple, exemplary or consequential damages (including, without limitation, lost profits or revenue, or loss of goodwill) relating to or resulting from performance or non-performance of this Amended Agreement or otherwise.

SECTION 17.0
SEVERABILITY

If any provision of this Amended Agreement or the application thereof to any person or circumstances is, to any extent, held to be invalid or unenforceable by a court of competent jurisdiction, the remainder of this Amended Agreement, or the application of such provision to persons or circumstances other than those as to which it is held to be invalid or unenforceable, will not be affected thereby, and each provision of this Amended Agreement shall be valid and enforceable to the fullest extent permitted by law.

SECTION 18.0
REGULATORY APPROVAL AND AMENDMENT

18.1 Regulatory Approval. The Parties agree to support the filing with and approval by the FERC and RUS of this Amended Agreement. Any material changes or conditions imposed by any governmental authority with competent jurisdiction, any of which are unacceptable to a Party after the Parties' good faith attempt to negotiate a resolution to such objectionable change or condition, shall be cause for termination of this Amended Agreement upon thirty (30) days' prior written notice by the nonconsenting Party to the other Party.

18.2 Section 205 and 206 Rights.

18.2.1 Notwithstanding any provision in this Amended Agreement to the contrary, each Party may (a) unilaterally make application to the FERC under Section 205 of the Federal Power Act and pursuant to the FERC's rules and regulations promulgated thereunder for a change in any rate, term, condition, charge, classification of service, rule or regulation under or related to this Amended Agreement and/or (b) exercise its rights under Section 206 of the Federal Power Act and pursuant to the FERC's rules and regulations promulgated thereunder with respect to any rate, term, condition, charge, classification of service, rule or regulation for any

services provided under this Amended Agreement over which the FERC has jurisdiction.

18.2.2 Notwithstanding any provision in this Amended Agreement to the contrary, MISO may unilaterally make application to the FERC under Section 205 of the Federal Power Act and pursuant to the FERC's rules and regulations promulgated thereunder for a change in any term, rate, term, condition, charge, classification of service, rule or regulation under or related to this Amended Agreement.

18.2.3 In the event either Party or MISO exercises its rights under this Section 18.2, it shall provide to the other Party and/or MISO a copy of its filing with the FERC exercising such rights on the first business day immediately following the date on which such filing is made with the FERC.

18.3 Amendments. Except as provided for in this Section 18.0, this Amended Agreement may only be modified, amended, changed or supplemented in writing signed by both Parties and MISO. Any amendment executed pursuant to the terms of this Section 18.3 shall not be effective until approved or accepted for filing by the FERC and RUS.

18.4 Standard of Review. The standard of review the FERC shall apply when acting on proposed modifications to this Amended Agreement, either on the FERC's own motion or on behalf of a signatory or non-signatory shall be the 'just and reasonable' standard of review rather than the 'public interest' standard of review.

18.5 eTariff Considerations. In accordance with the provisions of paragraph 63 of FERC Order No. 714 (*Electronic Tariff Filings*, 124 FERC ¶ 61,270 at P 63 (2008)), the Parties agree that this Amended Agreement shall be housed in _ KU's eTariff database on the FERC website. KU shall be responsible for filing the Amended Agreement, and MISO and the other Party shall file certificates of concurrence with this Agreement. Nevertheless, KU agrees that it shall facilitate the other Party's exercise of its respective Section 205 rights pursuant to Section 18.4 by processing and submitting for filing any such Section 205 filing, pursuant to the Commission's then-effective electronic tariff filing requirements.

18.6 ISO Affiliation. In the event either Party modifies its ISO affiliation and such modification results in a change of functional control of the operation of the Interconnection Facilities, then the Parties agree that they shall amend this Amended Agreement as may reasonably be necessary to recognize any changes to this Amended Agreement that result.

SECTION 19.0
GOVERNING LAW; DISPUTE RESOLUTION AND INTERPRETATION

19.1 Applicable Law. This Amended Agreement and all rights, obligations and performances hereunder are subject to all applicable federal and state laws and to all duly promulgated

orders and other duly authorized action of any governmental authority with competent jurisdiction.

19.2 Governing Law. This Amended Agreement is to be governed by and construed in accordance with federal law where applicable and, when not in conflict with or preempted by federal law, applicable laws of the State of Kentucky.

19.3 Dispute Resolution.

19.3.1 Any controversy, claim or dispute of whatsoever nature or kind between or among the Parties arising out of or in connection with this Amended Agreement or its validity or interpretation (each a "Dispute") shall be resolved pursuant to the procedures of this Section 19.3.

19.3.2 Any Party to a Dispute (other than a Dispute with respect to the Tariff or the OATT or other applicable open access transmission tariff, which shall be resolved in accordance with the dispute resolution terms therein) may provide written notice thereof to the other Party, including a reasonably detailed description of the subject matter of the Dispute (the "Dispute Notice").

19.3.3 Upon the issuance or receipt of a Dispute Notice, each Party shall promptly designate a senior executive responsible for the subject matter of the Dispute who shall have authority to resolve the Dispute. The senior executives shall promptly meet at a time and place mutually acceptable to the senior executives.

19.3.4 Disputes which are not resolved by the senior executives within thirty (30) days of their first meeting or such later date as the senior executives may mutually agree, may, upon mutual agreement of the Parties, be submitted to arbitration in accordance with the following provisions of this Section 19.3.4. In the event the Parties do not agree to submit such dispute to arbitration, each Party may exercise whatever rights and remedies it may have at equity or law consistent with the terms of this Amended Agreement.

19.3.4.1 Any arbitration initiated under this Section 19.3.4 shall be conducted before a single neutral arbitrator appointed by the Parties, unless the Parties are unable to agree on a single arbitrator. If the Parties fail to reach agreement on a single arbitrator within ten (10) days of referral of the Dispute to arbitration, the arbitration will be conducted by a panel of three (3) arbitrators. In such event, each Party shall select an arbitrator and provide notice thereof to the other Party. The two selected arbitrators shall promptly meet to agree on the selection of a third arbitrator, who shall serve as the chairperson. If the two selected arbitrators cannot agree on a third arbitrator, then the third arbitrator shall be selected pursuant to the Commercial Arbitration Rules of the American Arbitration Association. All arbitrators shall be knowledgeable in electric utility matters, including electric transmission

and bulk power issues, and shall not have any current or past substantial business or financial relationships with any of the Parties, except prior arbitrations.

19.3.4.2 Except as otherwise expressly set forth herein to the contrary, the arbitration shall be conducted in accordance with the Commercial Arbitration Rules of the American Arbitration Association then in force and effect.

19.3.4.3 Unless otherwise agreed by the Parties, the arbitrators shall render a decision within ninety (90) days of appointment and shall notify the Parties in writing of such decision and the reasons therefore.

19.3.4.4 The arbitrator(s) shall be authorized only to interpret and apply the provisions of this Amended Agreement and shall have no power to modify or change this Amended Agreement in any manner.

19.3.4.5 The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered into any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on grounds that the conduct of the arbitrator(s), or the decision itself, violated standards set forth in Federal Arbitration Act.

19.3.4.6 Each Party shall be responsible for its own costs incurred during the arbitration process. The Parties shall equally share the cost of a single arbitrator. If the dispute is arbitrated before a panel of three (3) arbitrators, each Party shall bear the cost of the arbitrator appointed by that Party and shall equally share the cost of the third arbitrator.

19.4 No Presumption. This Amended Agreement shall be construed without regard to any presumption or other rule requiring construction against the Party causing this Amended Agreement to be drafted.

19.5 Conflicts. In the event of a conflict between the main body of this Amended Agreement and any Appendix hereto, the terms of the main body of this Amended Agreement shall govern.

SECTION 20.0
ENTIRE AGREEMENT

This Amended Agreement states the rights of the Parties with respect to the transactions contemplated by this Amended Agreement and supersedes all prior agreements, oral or written, with respect to the subject matter hereof, including the 2006 IA.

SECTION 21.0
EFFECT OF MISO SIGNATURE

The Parties acknowledge and understand that the signature of the authorized representative of MISO on this Amended Agreement is for the limited purpose of acknowledging that the representative of MISO has read the terms of this Amended Agreement. The Parties and MISO further state that they understand that FERC desires that the Parties keep MISO fully apprised of the matters addressed herein as well as any reliability and planning issues that may arise under this Amended Agreement, and that the signature of a MISO officer shall not be in anyway deemed to imply that MISO is taking responsibility for the actions of either Party, that MISO has any affirmative duties under this Agreement, and that MISO is not liable in any way under this Amended Agreement.

SECTION 22.0
COUNTERPARTS

This Amended Agreement may be executed in separate or multiple counterparts, all of which shall evidence a single agreement.

IN WITNESS HEREOF, this Amended and Restated Interconnection Agreement has been duly executed by the Parties hereto as of the date first above written.

LG&E/KU Services, Inc.
acting on behalf of Kentucky Utilities Company,

By: _____ DATE 6/17/13

Name: Tom Jessee
Title: VP, Transmission

Big Rivers Electric Corporation

By: _____

Name: Mark A. Bailey
Title: President & CEO

The signature below of the authorized officer of M ISO is for the limited purpose of acknowledging that an authorized officer of MISO has read this Amended Agreement.

Midcontinent Independent System Operator, Inc.

By: _____ 06-04-13

WILLIAM C. PHILLIPS
Vice President
Reliability & Security Relations

Name: William C. Phillips
Title: Vice President, Reliability & Security Relations

Attachment for Response to KIUC 2-49(a)

Appendix I

List of Facility Schedules

(Points of Interconnection)

FACILITY SCHEDULE NO. 1

1. **Name:** Hardinsburg Interconnection Point

2. **Facility Location:** At the point where Big Rivers 138 kV single circuit transmission line extending from Big Rivers Hardinsburg 138kV substation is connected at the KU's Hardinsburg 138 kV station..

3. **Big Rivers-Owned Interconnection Facilities:**

4. **KU-Owned Interconnection Facilities:** The interconnection metering is owned by KU and is located in KU's Hardinsburg 138 kV station

5. **Operation and Maintenance Responsibilities:** KU and Big Rivers shall each operate and maintain the facilities it owns or controls.

6. **One-Line Diagram:**

7. **Normal Operation of Interconnections:** Closed

8. **Delivered Voltages:** 138kV **Metered Voltages:** 138kV

9. **Metered:** Telemetered

10. **Other Terms and Conditions:**

Appendix I **(continued)**

List of Facility Schedules
(Points of Interconnections)

FACILITY SCHEDULE NO. 2

1. **Name:** Green River Interconnection Point

2. **Facility Location:** At the point where Big Rivers 161 kV single circuit transmission line extending from Big River's Wilson 345/161 kV station is connected to the KU Green River 161/138/69 kV station.

3. **Big Rivers-Owned Interconnection Facilities:**

4. **KU-Owned Interconnection Facilities:** The interconnection metering is owned by KU and is located in the KU Green River 161/138/69 kV substation

5. **Operation and Maintenance Responsibilities:** KU and Big Rivers shall each operate and maintain the facilities it owns or controls.

6. **One-Line Diagram:**

7. **Normal Operation of Interconnections:** Closed

8. **Delivered Voltages:** 161kV **Metered Voltages:** 161kV

9. **Metered:** Telemetered

10. **Other Terms and Conditions:**

Attachment for Response to KIUC 2-49(a)

Appendix I **(continued)**

List of Facility Schedules
(Points of Interconnections)

FACILITY SCHEDULE NO. 3

1. **Name:** Daviess County #1 Interconnection Point

2. **Facility Location:** At the point where Big Rivers 345 kV single circuit transmission line extending from Big River's Wilson EHV Station is connected to the KU Daviess County 345 kV Station.

3. **Big Rivers-Owned Interconnection Facilities:**

4. **KU-Owned Interconnection Facilities:** The interconnection metering is owned by KU and is located at the KU Daviess County 345 kV Station

5. **Operation and Maintenance Responsibilities:** KU and Big Rivers shall each operate and maintain the facilities it owns or controls.

6. **One-Line Diagram:** Exhibit 2, Figure 1

7. **Normal Operation of Interconnections:** Closed

8. **Delivered Voltages:** 345kV **Metered Voltages:** 345kV

9. **Metered:** Telemetered

10. **Other Terms and Conditions:**

A. Schedule

B. Payment

C. Future Upgrades

Big Rivers agrees to reimburse KU for the properly documented, reasonable, and necessary costs of maintaining, repairing, or replacing the breakers and associated bus work for the Daviess County #1 Interconnection Points and the costs of maintaining the 345 kV bus of the Daviess County Substation. If KU should, in the future, expand or modify the Daviess County Substation for its own use and benefit or for the benefit of any third party, then Big Rivers and KU shall re-define the responsibilities of each party with respect to maintenance, repair, and replacement costs thereafter.

Attachment for Response to KIUC 2-49(a)

D. Other

Flowgate recognition: Big Rivers agrees to recognize the posted "Available Flowgate Capability" for KU flowgates, as defined in the Joint Reliability Coordination Agreement among and between MISO, PJM and TVA in evaluating and approving Firm Point-to-Point Transmission Service requests under the MISO Open Access Transmission Tariff. KU agrees to recognize the posted "Available Flowgate Capability" for Big Rivers flowgates, as defined in the Joint Reliability Coordination Agreement among and between MISO, PJM and TVA, for the KU Flowgates above in evaluating and approving Firm Point-to-Point Transmission Service requests under the LG&E/KU Open Access Transmission Tariff.

Attachment for Response to KIUC 2-49(a)

Appendix I **(continued)**

List of Facility Schedules
(Points of Interconnections)

FACILITY SCHEDULE NO. 4

1. **Name:** Daviess County #2 Interconnection Point

2. **Facility Location:** At the point where Big River's 345 kV single circuit transmission line extending from Big River's Coleman EHV Station is connected to the KU Daviess County 345 kV Station.

3. **Big Rivers-Owned Interconnection Facilities:**

4. **KU-Owned Interconnection Facilities:** The interconnection metering is owned by KU and is located at the KU Daviess County 345 kV Station

5. **Operation and Maintenance Responsibilities:** KU and Big Rivers shall each operate and maintain the facilities it owns or controls.

6. **One-Line Diagram:** Exhibit 2, Figure 1

7. **Normal Operation of Interconnections:** Closed

8. **Delivered Voltages:** 345kV **Metered Voltages:** 345kV

9. **Metered:** Telemetered

10. **Other Terms and Conditions:**

E. Schedule

F. Payment

G. Future Upgrades

Big Rivers agrees to reimburse KU for the properly documented, reasonable, and necessary costs of maintaining, repairing, or replacing the breakers and associated bus work for the Daviess County #2 Interconnection Points and the costs of maintaining the 345 kV bus of the Daviess County Substation. If KU should, in the future, expand or modify the Daviess County Substation for its own use and benefit or for the benefit of any third party, then Big Rivers and KU shall re-define the responsibilities of each party with respect to maintenance, repair, and replacement costs thereafter.

H. Other

Flowgate recognition: Big Rivers agrees to recognize the posted "Available Flowgate Capability" for KU flowgates, as defined in the Joint Reliability Coordination Agreement among and between MISO, PJM and TVA in evaluating and approving Firm Point-to-Point Transmission Service requests under the MISO Open Access Transmission Tariff. KU agrees to recognize the posted "Available Flowgate Capability" for Big Rivers flowgates, as defined in the Joint Reliability Coordination Agreement among and between MISO, PJM and TVA, for the KU Flowgates above in evaluating and approving Firm Point-to-Point Transmission Service requests under the KU Open Access Transmission Tariff.

Attachment for Response to KIUC 2-49(a)

Appendix I **(continued)**

List of Facility Schedules
(Points of Interconnections)

FACILITY SCHEDULE NO. 5

[Reserved]

Attachment for Response to KIUC 2-49(a)

Appendix I **(continued)**

List of Facility Schedules
(Points of Interconnections)

FACILITY SCHEDULE NO. 6

1. **Name:** Matanzas Substation Point of Interconnection

2. **Facility Location:** (37 degrees 25 minutes 20.09 seconds N, 88 degrees 00 minutes 29.31 seconds W). The Point of Interconnection will be at the point where the Big Rivers Wilson to New Hardinsburg/TVA Paradise 161kV transmission line interconnects with the KU Matanzas Substation at the KU Matanzas Tap Structure.

3. **Big Rivers -Owned Interconnection Facilities:**
   - 500 ft of two parallel 161 kV transmission lines on single circuit structures to interconnect the BREC Wilson to New Hardinsburg/TVA Paradise 161 kV transmission line.
   - Poles, insulators, associated equipment, and easement for the two parallel 161 kV transmission line on single circuit structures to interconnect the Big Rivers Wilson to New Hardinsburg/TVA Paradise 161 kV transmission line into KU Matanzas Substation along with connection to the KU Matanzas Tap Structure.

4. **KU-Owned Interconnection Facilities:**
   - 675 ft of two parallel 138 kV transmission line on single circuit structures to interconnect the KU Green River to Ohio County 138 kV transmission line into the KU Matanzas Substation.
   - Poles, insulators, associated equipment, and easement for the KU 138kV Loop.
   - The KU Matanzas Substation
     - 161 kV breaker and a half configuration,
     - a 138 kV breaker and a half configuration,
     - two 161/138 kV - 200 MVA transformers,
     - two tap structures and insulators for the Big Rivers Wilson to New Hardinsburg/TVA Paradise 161 kV transmission line,
     - two tap structures and insulators structures for the KU Green River to Ohio County 138 kV transmission line communication equipment, and;
     - Metering equipment with two remote terminal units ("RTUs")

5. **Operation and Maintenance Responsibilities:**
   KU and Big Rivers shall each operate and maintain the facilities and equipment it owns or controls. An Operating Committee made up of both parties shall establish:
   - coordinated safety and other appropriate protocols for the operation of the Interconnection Point circuit breakers and switches prior to initial energization.
   - Coordinated annual maintenance and testing of KU owned metering equipment.

6. **One-Line Diagram:** At Exhibit B, Figure 2.

7. **Normal Operation of Interconnection:** Closed

8. **Delivered Voltage:** 161 kV; **Metered Voltage:** 161 kV;
   Loss Adjustment due to Meter Location: No

9. **Metered:** Telemetered at Matanzas Substation. Tie-line metering will be on the:
   - KU Matanzas to Big Rivers Wilson 161 kV line
   - KU Matanzas to Big Rivers New Hardinsburg/TVA Paradise 161 kV line

10. **Other Terms and Conditions:**

J. Schedule

The planned energization date for the Matanzas interconnection point and all associated facilities listed above is to be determined by the Parties. Both Parties will take all reasonable actions necessary to ensure that the interconnection is completed by this date. If either Party becomes unable to meet this date, the two Parties will consult as soon as the delay becomes apparent, and agree to a new energization date.

K. Payment

The overall estimated cost for this project is $17,035k. **Big Rivers** will allow KU to perform the engineering, design, and construction subject to adhere to BREC design and construction standards. KU shall provide all necessary as built drawings and other documentation as requested by BREC.

L. Future Upgrades

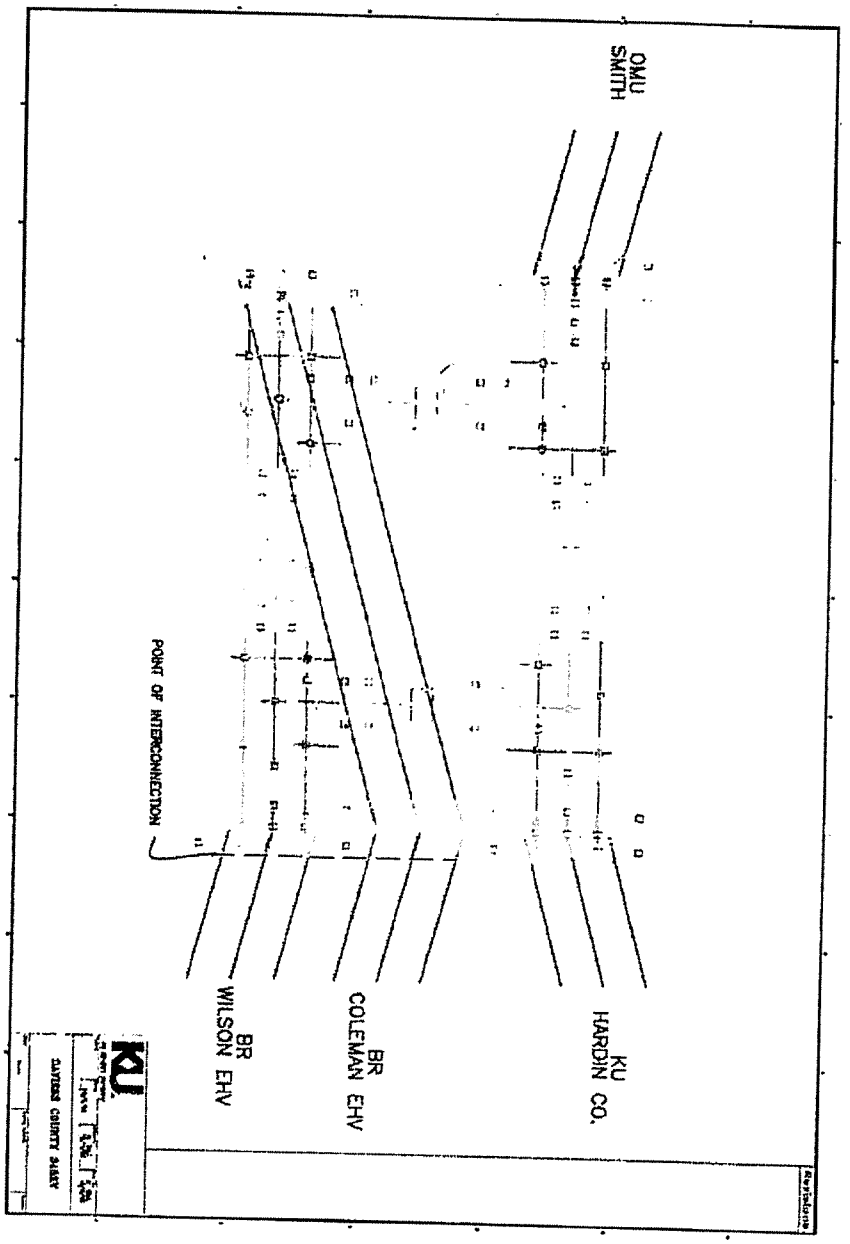
If either Party plans system additions or upgrades in the future to the Matanzas Substation, the Party proposing the changes will seek the consent of the other Party prior to implementing any such changes. Such consent shall not be unreasonably withheld. The Parties shall negotiate in good faith regarding cost allocation of any upgrades proposed by a Party that require changes to be made on the other Party's transmission system.

M. Other

The Parties may mutually agree to revise the scope and/or timing of the upgrades based on updated powerflow studies and/or other engineering assessments performed at the request of either Party. The costs provided for the above upgrades are good-faith estimates only.

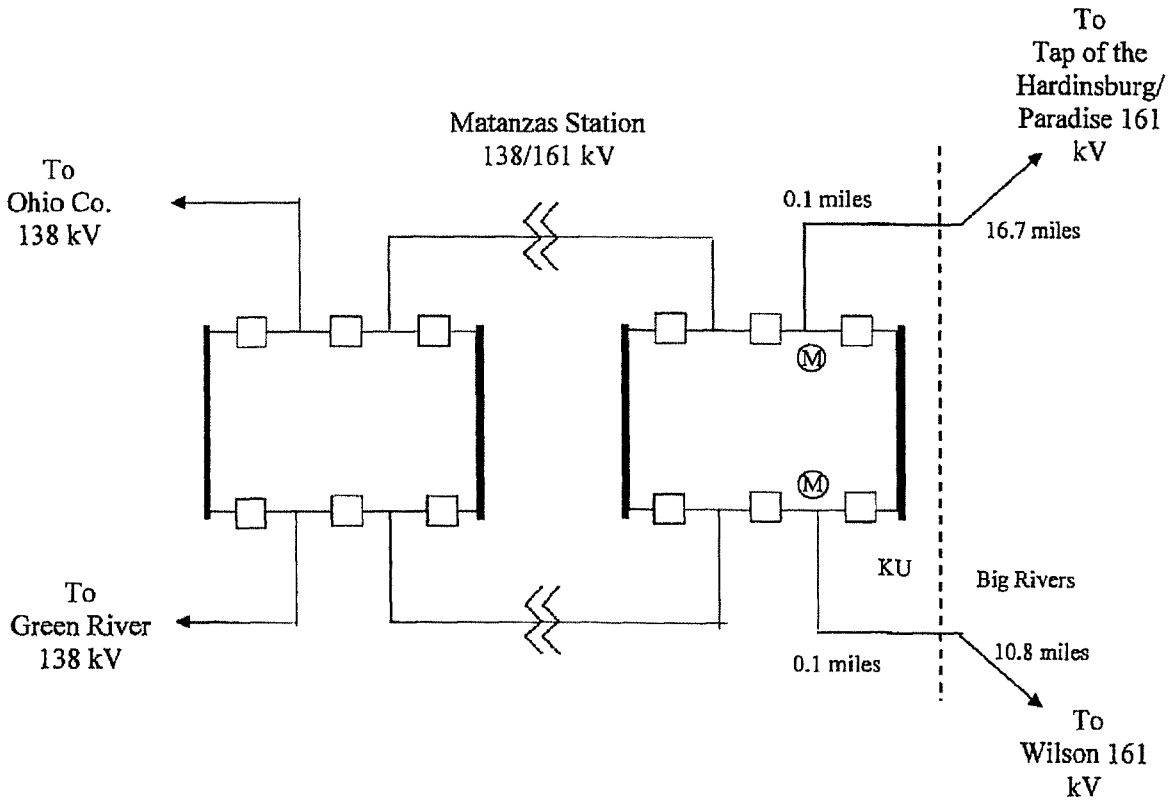
Attachment for Response to KIUC 2-49(a)

Appendix IIFIGURE 1 - Daviess County #1 & #2 Interconnection Point



Attachment for Response to KIUC 2-49(a)

Appendix II (continued)
Figure 2 -
Matanzas– Big Rivers Wilson Interconnection Point
Matanzas – Big Rivers New Hardinsburg/TVA Paradise Interconnection Point



Attachment for Response to KIUC 2-49(b)

AMENDED AND RESTATED

INTERCONNECTION AGREEMENT

Among

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
d/b/a Vectren Energy Delivery of Indiana, Inc.

BIG RIVERS ELECTRIC CORPORATION

and

MIDWEST INDEPENDENT TRANSMISSION
SYSTEM OPERATOR, INC.

Attachment for Response to KIUC 2-49(b)

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AMENDED

INTERCONNECTION AGREEMENT

AMONG

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
d/b/a Vectren Electric Delivery of Indiana, Inc.

BIG RIVERS ELECTRIC CORPORATATION

MIDWEST INDEPENDENT TRANSMISSION
SYSTEM OPERATOR, INC.

0.01. THIS AMENDED INTERCONNECTION AGREEMENT, dated as of this 4th day of December, 2012 ("Agreement") among SOUTHERN INDIANA GAS AND ELECTRIC COMPANY, d/b/a Vectren Energy Delivery of Indiana, Inc. an Indiana corporation (sometimes hereinafter called "**Vectren**"), BIG RIVERS ELECTRIC CORPORATION, a Kentucky corporation (sometimes hereinafter called "**Big Rivers**"), and the MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC., a non-profit, non-stock corporation organized and existing under the laws of the State of Delaware (sometimes hereinafter called the "**Midwest ISO**"). Big Rivers or Vectren may be sometimes individually called "Transmission-Owning Party" and collectively called "Transmission-Owning Parties." Big Rivers, Vectren or the Midwest ISO may be sometimes called individually as "Party" or collectively as "Parties."

WITNESSETH:

0.02. **WHEREAS**, Big Rivers owns electric facilities and is engaged in generation, transmission, and sale of electric power and energy within the Commonwealth of Kentucky; and

0.03 **WHEREAS**, Vectren owns electric facilities and is engaged in generation, transmission, distribution and sale of electric power and energy within the State of Indiana; and

0.04. **WHEREAS**, the respective electric transmission systems of Big Rivers and Vectren have for many years been interconnected; and

0.05. **WHEREAS,** the Midwest ISO has functional control of the operation of the Transmission Owning Parties' transmission systems, as defined in Sections 1.5 and 1.23 of this Agreement, and is responsible for providing transmission and interconnection service on the transmission facilities under its functional control; and

0.06. **WHEREAS**, there is now in force and effect among Big Rivers and Vectren an Interconnection Agreement dated as of July 5, 1973; a Modification Number 1 thereto, dated as of July 5, 1973; a Modification Number 2 thereto, dated as of December 15, 1975; a

Modification Number 3 thereto, dated as of October 1, 1978; a Modification Number 4 thereto, dated as of February 1, 1980; a Modification Number 5 thereto, dated April 20, 1981; and a Modification Number 6 thereto, dated December 1, 1982 (hereinafter called the "Interconnection Agreement"); and

0.07. **WHEREAS**, Big Rivers and Vectren have further studied other additional mutual benefits and advantages that may be realized by the interconnected operation of their respective transmission systems, and, as a result thereof, desire to amend the Interconnection Agreement to include certain additional facilities; and

0.08. **WHEREAS**, the Transmission-Owning Parties desire to continue the interconnection of their respective transmission systems under the terms and conditions, set forth in the Interconnection Agreement as amended and restated herein; and

0.09. **WHEREAS**, the Transmission-Owning Parties are subject to regulation by the Federal Energy Regulatory Commission (sometimes hereinafter called "FERC"); and Vectren is subject to regulation by the Indiana Utility Regulatory Commission (sometimes hereinafter called "IURC"); and Big Rivers is subject to regulation by the Kentucky Public Service Commission (sometimes hereinafter called "KYPSC"); and

0.10. **WHEREAS**, Big Rivers and Vectren are participating Transmission Owners in the Midwest ISO and have dedicated functional control of the operation of the Transmission Owning Parties' transmission systems to the Midwest ISO; and

0.11. **NOW, THEREFORE**, in consideration of the premises and of the mutual covenants herein set forth, the Parties agree as follows:

ARTICLE 1
DEFINITIONS

1.0 Terms used in this Agreement with initial capitalization not otherwise defined shall have the meanings specified in the Midwest ISO Tariff.

1.1 "Abnormal Condition" means any condition on the Vectren Transmission System, the Interconnection Facilities, or the Big Rivers Transmission System that is outside normal operating parameters, such that, such facilities are operating outside their normal ratings or reasonable operating limits have been exceeded but which has not resulted in an Emergency. An Abnormal Condition may include, but is not limited to, high or low deviations in voltage, frequency, power flow, equipment temperature, equipment pressures, and other equipment and operating parameters.

1.2 "Agreement" means this Amended Interconnection Agreement among Vectren, Big Rivers and the Midwest ISO, including all exhibits attached hereto and any amendments thereto.

Attachment for Response to KIUC 2-49(b)

1.3 "Big Rivers" means Big Rivers Electric Corporation and its permitted successors and assigns.

1.4 "Big Rivers-Owned Interconnection Facilities" means all those facilities or portions of facilities owned by Big Rivers, which, in conjunction with the Vectren-Owned Interconnection Facilities, are necessary to effect the transfer of energy to and from the Big Rivers Transmission System and allow the provision of ancillary services, as such facilities are identified and described in Facility Schedule(s), as agreed to by the Transmission-Owning Parties and to be attached hereto and incorporated herein by this reference, and shall include any modifications, additions, or upgrades made to those facilities.

1.5 "Big Rivers Transmission System" means the transmission facilities owned, operated or controlled by Big Rivers, including conductors, circuit breakers, switches, transformers and other associated equipment used to control the transfer of energy from one place to another, and shall include any modifications, additions, or upgrades made to those facilities.

1.6 "Emergency" has the meaning customarily attributed to it in the electric utility industry in the United States, including, without limitation, any condition on the Interconnection Facilities, the Big Rivers Transmission System, the Vectren Transmission System or the transmission system of other utilities which is likely to result in imminent significant disruption of service to consumers or is imminently likely to endanger life or property.

1.7 "Facility Schedule" means the attached terms and conditions which specify the responsibilities of the Transmission-Owning Parties for the ownership and costs applicable to Interconnection Points.

1.8 "FERC" means the Federal Energy Regulatory Commission or any successor agency.

1.9 "Interconnection Facilities" means the Big Rivers-Owned Interconnection Facilities and the Vectren-Owned Interconnection Facilities collectively, as described in the attached Facility Schedule(s).

1.10 "Interconnection Point(s)" shall mean the points(s) of delivery at which the transmission systems of the Transmission-Owning Parties are connected.

1.11 "IURC" means the Indiana Utility Regulatory Commission or any successor agency.

1.12 "KYPSC" means the Kentucky Public Service Commission or any successor agency.

1.13 "Midwest ISO" means the Midwest Independent Transmission System Operator, Inc., or any other independent system operator or regional transmission organization or group that is responsible for functional control of the Transmission Owning Parties' transmission systems, or any successor organization(s).

1.14 "NERC" means the North American Electric Reliability Corporation or any successor organization.

1.15 "Tariff" means the Open Access Transmission, Energy and Operating Reserve Markets Tariff, Midwest ISO FERC Electric Tariff, Fifth Revised Vol. 1, on file with the FERC and in effect, as amended or superseded from time to time or the open access transmission tariff filed by Vectren or Big Rivers as filed with the FERC and as it may be amended from time to time, or any successor tariff under which the transmission and interconnection service over the Transmission Owning Parties' transmission systems is provided.

1.16 "Operating Committee" shall have that meaning provided in Article 8 of this Agreement.

1.17 "Parties" means Vectren, Midwest ISO and Big Rivers, and their permitted successors and assigns.

1.18 "Party" means any of Vectren, Midwest ISO or Big Rivers, and its respective permitted successors and assigns.

1.19 "Transmission-Owning Parties" means Vectren and Big Rivers, and their permitted successors and assigns.

1.20 "Transmission-Owning Party" means either Vectren or Big Rivers, and its respective permitted successors and assigns.

1.21 "Vectren" means the Vectren Energy Delivery of Indiana and its permitted successors and assigns.

1.22 "Vectren-Owned Interconnection Facilities" means all those facilities or portions of facilities owned by Vectren, which, in conjunction with the Big Rivers-Owned Interconnection Facilities, are necessary to effect the transfer of energy to and from the Vectren Transmission System and allow the provision of ancillary services, as such facilities are identified and described in Facility Schedule(s) to this Agreement, and shall include any modifications, additions, or upgrades made to those facilities.

1.23 "Vectren Transmission System" means the transmission facilities owned, operated or controlled by Vectren including conductors, circuit breakers, switches, transformers and other associated equipment used to control the transfer of energy from one place to another, and shall include any modifications, additions, or upgrades made to those facilities.

ARTICLE 2
PROVISIONS FOR, AND CONTINUITY OF INTERCONNECTED OPERATION

Interconnection Points

2.01. The Big Rivers 138 kV Transmission System and the Vectren 138 kV Transmission System are connected by a single circuit 138 kV transmission line extending from

the Big Rivers Henderson 161/138 kV Substation located in Henderson County, Kentucky to the Vectren A.B. Brown 138 kV Substation located in Posey County, Indiana (hereinafter called "A.B. Brown - Henderson 138 kV Interconnection Point"), as further described in the Facility Schedule (Attachment A to this Agreement). Vectren owns the line from the A.B. Brown 138 kV Substation to the last Vectren structure on the Indiana side of the Ohio River that is mutually agreed by both parties to be the point of river crossing. Big Rivers owns the line from the Henderson County 161/138 kV Substation to the first Vectren structure on the Indiana side of the Ohio River that is mutually agreed by both parties to be the point of river crossing. The river crossing structures on both sides of the river are owned by Big Rivers (See EXHIBIT III, Figure 1).

2.02. The Big Rivers 345 kV Transmission System and the Vectren 345 kV Transmission System are connected by a single circuit 345 kV transmission line extending from the Vectren A.B. Brown 345 Substation located in Posey County, Indiana to the Big Rivers Reid EHV Substation located in Webster County, Kentucky (hereinafter called "A.B. Brown - Reid 345 kV Interconnection Point"), as further described in the Facility Schedule (Attachment B to this agreement). Vectren owns the line from the Vectren A.B. Brown 345 Substation to line terminal structure located within the Big Rivers Reid EHV Substation (See EXHIBIT III, Figure 2).

Synchronous Operation

2.03. The Transmission-Owning Parties mutually agree that, through the A.B. Brown - Henderson 138 kV Interconnection Point and the A.B. Brown - Reid 345 kV Interconnection Point, their respective systems will be continuously operated in parallel for durations of time specified by the Operating Committee, provided under Article 8 hereof (except in cases of interruption of such parallel operation due to necessary maintenance or due to causes beyond the control of either Transmission-Owning Party, or due to the necessity of an interruption of parallel operation in order that the consumers being directly served by either Transmission-Owning Party may continue to receive adequate service from such Transmission-Owning Party). If synchronous operation of the systems through a particular line or lines becomes interrupted, either manually or automatically, because of reasons beyond the control of either Transmission-Owning Party, or because of scheduled maintenance that has been agreed to by both Transmission-Owning Parties and approved by Midwest ISO, the Transmission-Owning Parties shall cooperate so as to remove the cause of such interruption as soon as practicable and restore such line or lines to normal operating condition.

Maintenance of Equipment

2.04. The Transmission-Owning Parties shall each keep, or shall cause to be kept, the lines, together with all associated equipment and appurtenances, described in Article 2 hereof that are located on their respective sides of the Interconnection Points in a suitable condition of repair at all times, each at its own expense, in order that said lines will operate in a reliable and satisfactory manner and in order that reduction of the capacity of said lines will be avoided to the extent practicable.

Attachment for Response to KIUC 2-49(b)

ARTICLE 3
SERVICES TO BE RENDERED

3.01. It is the purpose of the Transmission-Owning Parties to seek and realize, on an equitable basis, all benefits practicable to be effected through coordination in the operation and development of their respective systems. It is understood by the Transmission-Owning Parties that such benefits may be realized by them by carrying out, under stated terms and conditions, various interconnection services and transactions that may from time to time include among others:

(i) the furnishing of mutual emergency and standby assistance,

(ii) the transfer of electric energy through the transmission system of one Transmission-Owning Party for the benefit of the other, and

(iii) the coordination of maintenance schedules of generating and transmission facilities.

In furtherance of such purpose the Parties shall create, and continue in functioning an Operating Committee as provided under Article 8 hereof.

3.02. Inasmuch as the specific services to be rendered in furtherance of such purpose will vary from time to time during the duration of this Agreement, and the terms and conditions applicable to such services may require modification from time to time, it is intended that such specific services and the terms and conditions applicable thereto will be set forth in service schedules from time to time mutually agreed upon between the Transmission-Owning Parties. Such service schedules, until and unless changed by such mutual agreement, shall be those provided by Section 3.03 hereof. Each such service schedule shall be deemed a part of this Agreement during the period of its duration.

3.03. The respective service schedule designated:

Service Schedule B- Energy Transfer

which has been agreed upon among the Parties, is identified as Exhibit II to this Agreement, is attached hereto and is hereby made a part hereof the same as if incorporated herein.

ARTICLE 4
SERVICE CONDITIONS

Control of System Disturbance

4.01. The Transmission-Owning Parties shall maintain and operate their respective systems so as to minimize, in accordance with sound operating practice, the likelihood of disturbance originating in either of their systems which might cause impairment to the service of

the system of the other Transmission-Owning Party or of any system, including the Midwest ISO Transmission System, interconnected with the system of the other Transmission-Owning Party.

Control of Reactive Power Exchange

4.02. It is the intent that neither Transmission-Owning Party shall be obligated to deliver reactive power for the benefit of the other Transmission-Owning Party; also that neither Transmission-Owning Party shall be obligated to receive reactive power when to do so may introduce objectionable operating conditions on its system. The Operating Committee shall be responsible for the establishment from time to time of operating procedures and schedules, in respect of the provision of reactive power by one system for the other in order to secure adequate service and economical use of the facilities of both systems and in respect of proper charges, if any, for the use of facilities providing reactive power. In discharging such duties the Operating Committee shall recognize that in the transmission and delivery of power and energy hereunder the provision of reactive power by either of the Transmission-Owning Parties, in harmony with sound engineering principles of transmission operation with their systems interconnected, is subject to numerous variables contingent upon loading and operating conditions existing simultaneously on both of their systems. The operating procedures and schedules so set up by the Operating Committee shall be in accord with such principles and shall require each of the Transmission-Owning Parties to provide reactive power at such times and in such amounts as will be equitable to both Transmission-Owning Parties.

Control of Unscheduled Power Deliveries

4.03. The Parties hereto shall exercise due diligence and foresight in carrying out all matters related to the providing and operating of their respective electric power resources so as to minimize to the extent practicable deviations between actual and scheduled deliveries of electric power and energy between the Transmission-Owning Parties' transmission systems. The Parties shall provide and install on their respective systems such communication and telemetering facilities as are essential to so minimize such deviations; and, in developing and executing operating procedures that will enable the Parties to avoid, to the extent practicable, deviations from scheduled deliveries, shall fully cooperate with each other and with third parties whose systems are either directly or indirectly interconnected with the systems of the Transmission-Owning Parties and who of necessity, together with the third parties, must unify their efforts cooperatively to achieve effective and efficient interconnected operation. The Parties recognize, however, that, despite their best efforts to prevent the same, unscheduled deliveries of electric energy from one Transmission-Owning Party to the other may occur. Electric energy delivered hereunder in such event shall be settled for either by the return of equivalent energy or by payment of the out-of-pocket cost, such cost being as of the interconnection point or points, as provided for in Section 5.01 of this Agreement, taking into account electrical losses incurred from the source or sources of such energy to said delivery point or points to the supplying Party generating or acquiring such energy, plus ten percent of such cost. If equivalent energy is returned, it shall be returned at times when the load conditions of the Transmission-Owning Party receiving it are equivalent to the load conditions of such Transmission-Owning Party at the time the energy for which it is returned was delivered or, if such Transmission-Owning Party elects to have equivalent energy returned under different conditions, it shall be returned in such

amounts, to be agreed upon by the Operating Committee, as will compensate for the difference in conditions.

ARTICLE 5
INTERCONNECTION POINTS, METERING POINTS AND METERING

Interconnection Points

5.01. All electric energy delivered under this Agreement shall be of the character commonly known as three-phase, sixty-cycle energy, and shall be delivered at the Interconnection Points, as defined under Sections 2.01 and 2.02, hereof, at nominal voltages of 345,000 volts and 138,000 volts and at such other nominal voltages as may be agreed upon by the Parties.

Metering Points

5.02. Electric power and energy supplied and delivered under this Agreement shall be measured at the following Interconnection Points by

(i) suitable 345,000 volt metering equipment installed, owned and maintained by Big Rivers at Reid EHV Substation for the A.B. Brown – Reid 345 kV Interconnection Point; and

(ii) suitable 138,000 volt metering equipment installed, owned and maintained by Big Rivers at Henderson 161/138 kV Substation for the A.B. Brown - Henderson138 kV Interconnection Point.

Metering

5.03. Suitable metering equipment at the Interconnection Points as provided in Section 5.02 hereof shall include electric meters, potential and current transformers, and such other appurtenances as shall be necessary to give for each direction of flow the following quantities: (1) a continuous automatic graphic record of both kilowatts and kilovars, (2) an automatic record of the kilowatt-hours for each clock hour, and (3) a continuous integrating record of the kilowatt-hours.

5.04. Measurements of electric energy for the purpose of effecting settlements under this Agreement shall be made by standard types of electric meters installed and maintained, unless otherwise provided for in this Agreement, by the Transmission-Owning Party owning the meter at the Interconnection Points as provided under Section 5.02 above. The timing devices of all meters having such devices shall be maintained in time synchronism as closely as practicable. The meters shall be sealed and the seals shall be broken only upon occasions when the meters are to be tested or adjusted. For the purpose of checking the records of the metering equipment installed by one of the Transmission-Owning Parties as hereinabove provided, the other Parties shall have the right to install check metering equipment at the aforesaid metering points. Metering equipment so installed by one Party on the premises of a Transmission-Owning Party,

unless otherwise provided for in this Agreement, shall be owned and maintained by the Party installing such equipment. Upon termination of this Agreement, the Party owning such metering equipment shall remove it from the premises of the Transmission-Owning Party. Authorized representatives of all Parties shall have access at all reasonable hours to the premises where the meters are located and to the records made by the meters.

5.05. The aforesaid metering equipment shall be tested by the Party owning the equipment at suitable intervals and its accuracy of registration maintained in accordance with Good Utility Practice. On request of any Party a special test may be made at the expense of the Party requesting such special test. Representatives of any Party shall be afforded opportunity to be present at all routine or special tests and upon occasions when any readings, for purposes of settlements hereunder, are taken from meters not bearing an automatic record.

5.06. If at any test of metering equipment an inaccuracy shall be disclosed exceeding two percent, the account between the Transmission-Owning Parties for service theretofore delivered shall be adjusted to correct for the inaccuracy disclosed over the shorter of the following two periods: (1) for the thirty-day period immediately preceding the day of the test or (2) for the period that such inaccuracy may be determined to have existed. Should the metering equipment, as provided for under Section 5.03 hereof, at any time fail to register, the electric power and energy delivered shall be determined from the check meters, if installed, or otherwise shall be determined from the best available data.

ARTICLE 6
RECORDS AND STATEMENTS

Records

6.01. In addition to records of the metering provided for in Article 5, the Parties shall keep in duplicate such other records as may be needed to afford a clear history of the various deliveries of electric energy made by one Transmission-Owning Party to the other and of the clock-hour integrated demands in kilowatt-hours delivered by one Transmission-Owning Party to the other. In maintaining such records, the Transmission-owning Parties shall effect such segregations and allocations of demands and electric energy delivered into classes representing the various services and conditions as may be needed in connection with settlements under this Agreement. The originals of all such records shall be retained by the Party keeping the records for a minimum period of three years, or such longer period as may be required by the Midwest ISO or FERC, and the duplicates shall be delivered monthly to the other Party except as the Parties may agree upon a different time interval for such delivery.

Statements

6.02. As promptly as practicable after the end of each calendar month, the Parties shall cause to be prepared a statement setting forth the electric power and energy transactions between the Parties during such month in such detail and with such segregations as may be needed for operating records or for settlements under the provisions of this Agreement.

Attachment for Response to KIUC 2-49(b)

ARTICLE 7
BILLINGS AND PAYMENTS

7.01. All bills for amounts owed by one Party to another Party shall be due and payable on the fifteenth day of the month next following the monthly or other period to which such bills are applicable, or on the tenth day following receipt of bill, whichever date is later. The amount due shall be subject to a charge for interest computed at a floating prime rate from said due date to the date of payment. The applicable floating prime rate for each calendar month, or any part thereof, shall be, to the nearest one-hundredths of one percent, the prime rate as published in the Federal Reserve Statistical Release H.15, or its successor publication beginning with the month preceding the due date. The interest required to be paid hereunder shall be compounded monthly. Unless otherwise agreed upon, a calendar month shall be the standard monthly period for the purpose of settlements under this Agreement.

ARTICLE 8
OPERATING COMMITTEE

8.01. To coordinate the operation of their respective generating, transmission, and substation facilities, in order that the advantages to be derived hereunder may be realized by the Parties to the fullest practicable extend, the Parties shall establish a committee of authorized representatives to be known as the Operating Committee. Each of the Parties shall designate in writing delivered to the other Parties, the person who is to act as its representative on said committee (and the person or persons who may serve as alternate whenever such representative is unable to act). Such representative and alternate or alternates shall each be persons familiar with the generating, transmission, and substation facilities of the system of the Party by which he has been so designated, and each shall be fully authorized (1) to cooperate with the other representative (or alternates) and (2) from time to time as the need arises, subject to the declared intentions of the Parties herein set forth and to the terms hereof and the terms of any other agreements then in effect between the Parties, to determine and agree upon the following:

8.011. all matters pertaining to the coordination of maintenance of the generating and transmission facilities of the Transmission-Owning Parties;

8.012. all matters pertaining to the control of time, frequency, energy flow, kilovar exchange, power factor, voltage, and other similar matters bearing upon the satisfactory synchronous operation of the systems of the Transmission-Owning Parties; and

8.013. such other matters not specifically provided for herein upon which cooperation, coordination, and agreement as to quantity, time, method, terms and conditions are necessary in order that the operation of the systems of the Parties may be coordinated to the end that the potential savings will be realized to the fullest practicable extent that is agreed upon by the Parties.

8.02. For the purpose of inspection and reading of meters, checking of records, and all other pertinent matters, said representatives and their alternates, or their designees, shall have the

right of entry to all property of the Transmission-Owning Parties used in connection with the performance of this Agreement.

ARTICLE 9
FORCE MAJEURE

9.01 Neither the Transmission-Owning Parties nor the Midwest ISO shall be considered in default as to any obligation under this Agreement if prevented from fulfilling the obligation due to an event of Force Majeure. An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, curtailment (that is, any reduction in firm or non-firm transmission service in response to a transmission capacity shortage as a result of system reliability conditions), order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include an act of negligence or intentional wrongdoing by a Party. Any Party unable to fulfill any obligation by reason of Force Majeure shall make all reasonable efforts to perform its obligations under this Agreement.

ARTICLE 10
DURATION OF AGREEMENT

10.01. This Agreement shall become effective as of the date hereof and shall continue until July 1, 2037, at or after which date it may be terminated on October 31 of any year thereafter by either Transmission-Owning Party giving the other Parties at least thirty months' notice of termination, provided that the terminating Transmission-Owning Party has no outstanding contractual obligations to other Parties under this Agreement. No termination of this Agreement shall be effective until the Parties have complied with all legal requirements applicable to such termination.

ARTICLE 11
ARBITRATION

11.01. In the event any Party has a dispute, or asserts a claim, that arises out of or in connection with this Agreement or its performance, such Party (the "disputing Party") shall provide the other Parties with written notice of the dispute or claim. Such dispute or claim shall be referred to a designated senior representative of each Party for resolution on an informal basis as promptly as practicable after receipt of the notice by the other Parties. In the event the designated representatives are unable to resolve the claim or dispute through unassisted or assisted negotiations within thirty days of the non-disputing Parties' receipt of the notice, such claim or dispute shall be submitted for resolution in accordance with the dispute resolution procedures of the Midwest ISO Tariff.

Attachment for Response to KIUC 2-49(b)

11.02 Nothing in this Article 11 shall restrict the rights of any Party to file a complaint with FERC under relevant provisions of the Federal Power Act.

ARTICLE 12
LIABILITY

12.01. Each Transmission-Owning Party shall save and hold the other Parties free and harmless from and against liability, loss, damage and expense arising from or incident to injury or damage to persons or property occasioned by or in connection with its own facilities or the production or flow of electric energy by or through such facilities except when such injury or damage is due to the negligence or intentional wrongdoing of such other Party. The liability of the Midwest ISO shall be subject to and limited as provided in the Midwest ISO Tariff.

ARTICLE 13
TAXES

13.01. If at any time during the term hereof there should be levied or assessed against any of the Transmission-Owning Parties any direct tax by any taxing authority on the capacity or energy (or both) interchanged or exchanged by it, which tax is in addition to or different from the forms or such direct taxes as are now being levied or assessed, and such direct tax results in increasing the cost of any or all Parties in carrying out the provisions of this Agreement, then such increase shall be made in the charges for capacity or energy (or both) furnished by one Party to the others hereunder as is necessary in order to make adequate and equitable allowances for such tax.

ARTICLE 14
NOTICES

4.01. Except as herein otherwise provided, any notice which may be given to or made upon any Party by another Party under any of the provisions of this Agreement, shall be in writing unless it is otherwise specifically provided herein, and shall be treated as duly delivered when the same is either (a) personally delivered to the president or the vice president of Big Rivers, in the case of a notice to be given Big Rivers, or personally delivered to the president or a vice president of Vectren, in the case of a notice to be given Vectren, or personally delivered to the president of the Midwest ISO, in the case of a notice to be given to the Midwest ISO, or (b) deposited in the United States mail, postage prepaid and properly addressed to the above representatives of the Parties.

14.02. Any notice, request or demand pertaining to matters of an operating nature may be delivered by ordinary mail, messenger, telephone, facsimile transmission, or verbally as may be appropriate and shall be confirmed in writing as soon as practicable thereafter, if any Party so requests in any particular instance.

Attachment for Response to KIUC 2-49(b)

ARTICLE 15
REGULATORY AUTHORITIES

15.01. This Agreement is made subject to the jurisdiction of any governmental authority or authorities having jurisdiction in the premises and if any of the terms and conditions hereof are altered or made impossible of performance by the adjudication of any such governmental authority, the Parties shall negotiate in good faith any amendments to this Agreement necessary to adapt the terms of this Agreement to such adjudication. If the Parties are unable to agree upon a modification of such terms and conditions, then the Parties may proceed under Article 11 to resolve any disputes related thereto and each Party shall have the right to make a unilateral filing with FERC to modify this Agreement pursuant to Sections 205 or 206, as applicable, and FERC's rules and regulations thereunder. If a Party is unable to fully perform this Agreement due to the occurrence of an event described in this Section 15.01 and such inability is not based on an unwillingness or inability to pay, such Party shall not be deemed to be in default of its obligations under this Agreement, provided that such Party is seeking dispute resolution under Article 11 or before FERC, to the extent that (i) such Party is unable to perform as a result of such an event and (ii) such Party acts in accordance with its obligations under this Section 15.01.

ARTICLE 16
WAIVERS

16.01. The rights of any Party under this Agreement may not be waived except in writing signed by a duly authorized representative of such Party. Any waiver at any time by any Party of its rights with respect to a default under this Agreement, or with respect to any other matter arising in connection with this Agreement shall not be deemed a waiver with respect to any subsequent default or matter. Any delay, short of the statutory period of limitation, in asserting or enforcing any right under this Agreement, shall not be deemed a waiver of such right.

ARTICLE 17
ENTIRE AGREEMENT CONTAINED HEREIN

17.01. This Agreement constitutes the entire agreement among the Parties in respect of the subject matter hereof, and there are no other understandings or agreements among the Parties in respect thereof.

ARTICLE 18
CONSTRUCTION OF AGREEMENT

18.01. This Agreement shall be governed by and construed according to the laws of the State of Indiana.

Attachment for Response to KIUC 2-49(b)

ARTICLE 19
ASSIGNMENT

19.01. This Agreement shall inure to and bind the respective successors and assigns of the Parties, but the assignment thereof by any Party shall not relieve such Party, without the written consent of the other Parties, of any obligation to supply, or to take and pay for, as the case may be, the services herein contracted for.

ARTICLE 20
AMENDMENT OF INTERCONNECTION AGREEMENT

20.01. The Transmission-Owning Parties agree that the Interconnection Agreement shall be amended as of the effective date hereof, provided, however, that such amendment shall not in any way affect any right or claim to damages which either Transmission-Owning Party may have against the other Transmission-Owning Party because of any failure of such other Transmission-Owning Party to make any payment or keep or perform any other obligation which it had under the Interconnection Agreement up to the effective time of the amendment thereof.

ARTICLE 21
AMENDMENTS

21.01 Section 205 Rights. Notwithstanding any provision in this Agreement to the contrary, the Transmission-Owning Parties may unilaterally make application to the FERC under Section 205 of the Federal Power Act and/or pursuant to FERC's rules and regulations promulgated thereunder for a change in any rate or charge under or related to this Agreement. Additionally, the Parties may unilaterally make application to the FERC under Section 205 of the Federal Power Act and/or pursuant to the FERC's rules and regulations promulgated thereunder for a change in any term, condition, classification of service, rule or regulation under or related to this Agreement. In the event that a Party exercises its rights under this Section 21.01, it shall provide to the other Parties a copy of its filing with the FERC exercising such rights by the close of business on the first business day immediately following the date on which such filing is made with the FERC.

21.02 Section 206 Rights. Notwithstanding any provision in this Agreement to the contrary, the Parties may exercise their rights under Section 206 of the Federal Power Act and/or pursuant to FERC's rules and regulations promulgated thereunder with respect to any rate, term, condition, charge, classification of service, rule or regulation for any services provided under this Agreement over which the FERC has jurisdiction. In the event that a Party exercises its rights under this Section 21.02, it shall provide to the other Parties a copy of its filing with the FERC exercising such rights by the close of business on the first business day immediately following the date on which such filing is made with the FERC.

Attachment for Response to KIUC 2-49(b)

21.03 Amendments. Except for any action taken by FERC with respect to any filing as provided for in Section 21.01 and Section 21.02, this Agreement shall only be modified, amended, changed, or supplemented in writing signed by the Parties.

21.04 The Midwest ISO shall file this Agreement, and any Amendment to this Agreement with FERC as a service agreement under the Midwest ISO Tariff.

ARTICLE 22
COUNTERPARTS

22.01 This Agreement may be executed in any number of counterparts, and each executed counterpart shall have the same force and effect as an original instrument.

Attachment for Response to KIUC 2-49(b)

IN WITNESS WHEREOF the Parties have caused this Agreement to be executed by their duly authorized officers and their respective corporate seals to be hereunto affixed as of the date first above mentioned.

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
d/b/a Vectren Electric Delivery of Indiana, Inc.

By _____

Name: **Eric J. Schach**

Title: **Vice President, Energy Delivery**

BIG RIVERS ELECTRIC CORPORATION

By _____

Name: **Mark A. Bailey**

Title: **President and CEO**

MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.

By _____
Name WILLIAM C. PHILLIPS
Title Vice President
Standards Compliance & Strategy
12-04-12

Attachment for Response to KIUC 2-49(b)

EXHIBIT I

RESERVED

Attachment for Response to KIUC 2-49(b)

EXHIBIT II

SERVICE SCHEDULE B

ENERGY TRANSFER

SECTION 1 - DURATION

1.1. This Service Schedule, a part of and under the Agreement among Vectren, Big Rivers, and the Midwest ISO, shall become effective as of the date of the Agreement and shall continue in effect throughout the duration of the Agreement.

SECTION 2 - TRANSFER ARRANGEMENT

2.1. In carrying out the interconnected operation of their respective systems as provided for under the Agreement, energy being received by a portion of one Transmission-Owning Party's system from another portion of its system or from the system of another interconnected company, or energy being delivered by a portion of one Transmission-Owning Party's system to another portion of its system or to the system of another interconnected company, may flow over the transmission facilities of the other Transmission-Owning Party as a natural result of the physical and electrical characteristics of the interconnected network of transmission lines of which the transmission systems of the Transmission-Owning Parties are a part. Such flow of energy may occur during periods when conditions of system operation are normal or may occur during periods of emergency caused by the failure of either sources for power or transmission facilities, or both. In respect to such flow of energy (hereinafter called "Energy Transfer") the Transmission-Owning Parties agree as follows:

2.11. Such Energy Transfer over their respective transmission facilities shall be permitted when such transfer occurs; subject, however, to the understanding that such Energy Transfer shall not be of such magnitude or duration as to affect adversely or jeopardize the ability of the Transmission-Owning Party over whose system such Energy Transfer occurs to render proper service to its customers, and to render or accept service to or from companies pursuant to the Midwest ISO Tariff with which it now has or at any time hereafter it may have contractual agreements to furnish, take, or interchange power or energy, or both.

2.12. The Transmission-Owning Parties recognize that in carrying out the provisions of this Service Schedule, the above described Energy Transfer may occur during periods when either conditions of system operation are normal or the Transmission-Owning Party over whose system such Energy Transfer occurs is not affected adversely or jeopardized in meeting its own requirements as described under 2.11 above. In the event the need for such additional transmission facilities becomes apparent to any of the Parties during the duration if this Service Schedule, upon written notice given by any Party to the other Parties and as soon as practicable following such notice, the Parties shall jointly re-examine conditions relating to Energy Transfer. In such re-examination, if called for, the Transmission-Owning Parties shall agree upon such additional transmission facilities as may be required to be installed, if any, and

upon an equitable basis for bearing the cost of installation, maintaining and operating such facilities, if installed, in accordance with the Midwest ISO Tariff.

SECTION 3 - POWER AND ENERGY ACCOUNTING

3.1. The Parties recognize that Energy Transfer as described under Section 2 of this Service Schedule, except for such amounts of electrical losses as may be incurred because of such Energy Transfer, is the simultaneous acceptance and delivery of like amounts of power and energy by and from the system of the Transmission-Owning Party over whose system such Energy Transfer occurs. Power and energy associated with Energy Transfer, including electrical losses associated therewith, shall be accounted for each clock-hour as provided for under Article 5 of the Agreement. Proper consideration to such electrical losses will be in accordance with the manner agreed upon by the Operating Committee. It is understood by the Parties, however, that such electrical losses resulting from Energy Transfer, to be taken as losses over and above the losses prevailing under basic conditions agreed upon by the Parties, shall be supplied simultaneously by the Transmission-Owning Party for which such Energy Transfer is being made. The Parties have agreed that initially such basic conditions will be established as those that exist when the scheduled net delivery between the systems of the Transmission-Owning Parties, and between their respective systems and the systems of other interconnected companies, is zero kilowatts. It is further understood that, from time to time, conditions may require the establishment of different basic conditions for such purposes. Any Party by written notice given to the other Parties, may call for a prompt re-examination and reconsideration of matters pertinent to the establishment of said basic conditions, whenever such re-examination appears to be warranted, and the Parties will thereupon agree to effect such changes in the basic conditions, if any, that will equitably compensate the Transmission-Owning Parties for such losses. A statement to be prepared by the Parties at the end of each calendar month shall include in detail the amounts of energy delivered and received by the Transmission-Owning Parties that are associated with Energy Transfer and the amounts of electrical losses associated therewith.

Attachment for Response to KIUC 2-49(b)

ATTACHMENT A

AMENDED FACILITY SCHEDULE

Interconnection Facilities associated with the A.B. Brown-Henderson 138 kV Interconnection Point

1.01. Vectren will provide and install and will thereafter operate and maintain at its own expense the following facilities, to wit:

1.011. At A.B. Brown 138 kV Substation, the necessary 138 kV terminal equipment, including two 138 kV circuit breakers, disconnecting switches, associated control, protective, and relaying equipment and other facilities essential to the control and protection of the interconnecting transmission line.

1.012. A 138 kV transmission line (energized initially in 1975) hereby designated and herein called the A.B. Brown-Henderson 138 kV Line) constructed with conductors not smaller than 795 MCM in size and with suitable ground wires to extend in a general southerly direction from Vectren's A.B. Brown 138 kV Substation and terminating on the Vectren structure, located at that point on the Indiana side of the Ohio River that is mutually agreed by both parties to be the point of river crossing.

1.013. At A.B. Brown 138 kV Station, such communication, telemetering, and load control facilities as shall hereafter be determined by the parties as necessary for the proper and efficient interconnected operation of the parties' systems.

2.01. Big Rivers will provide and install, and will thereafter operate and maintain at its own expense, the following facilities, to wit:

2.011. At the Henderson 161/138 kV Substation, the necessary 161/138 kV transformer, circuit breakers, disconnecting switches, associated control, protective, and relaying equipment, and other facilities essential to the control and protection of the transformer and interconnecting transmission line.

2.012. A 138 kV transmission line (hereby designated and herein called the A.B. Brown-Henderson 138 kV Line) constructed with conductors not smaller than 795 MCM in size and with suitable ground wires to extend in a general northerly direction from Big River's Henderson 161/138 kV Substation and terminating on the Vectren structure, located at that point on the Indiana side of the Ohio River that is mutually agreed by both parties to be the point of river crossing.

2.013. At the Henderson 161/138 kV Substation, such communication, telemetering, and load control facilities as shall hereafter be determined by the parties as necessary for the proper and efficient interconnected operation of the parties' systems.

ATTACHMENT B

FACILITY SCHEDULE

Interconnection Facilities associated with the A.B. Brown - Reid 345 kV Interconnection Point

1.01. Vectren will provide and install and will thereafter operate and maintain at its own expense the following facilities, to wit:

1.011. A single circuit 345 kV transmission line (projected in service date December 2012).

1.012. Communications equipment required for telemetering of Vectren's required interconnection data.

1.02 Vectren will make all reasonable efforts to complete the facilities described in this Section no later than August, 2012 or such other date as Big Rivers and Vectren shall mutually agree upon.

1.03 Big Rivers shall provide Vectren with access over and through its appropriate right of way easements at no cost to allow Vectren to construct, own, maintain and improve the Interconnection Facilities.

2.01. Big Rivers will provide and install, and will thereafter operate and maintain at its own expense, the following facilities, to wit:

2.011. At the Reid EHV 345 kV Substation, the necessary 345 kV circuit breakers, substation bus, disconnecting switches, line terminals, and associated control, protective, and relaying equipment, and other facilities essential to the control and protection of the interconnecting transmission line along with interconnection metering.

2.012. Vectren shall reimburse Big Rivers' reasonable costs incurred for the initial cost of the equipment installed in Section 2.011 of this Agreement. The estimated cost of the equipment installed in Section 2.011 is $5.1M, however Vectren shall reimburse Big Rivers the actual cost of the project.

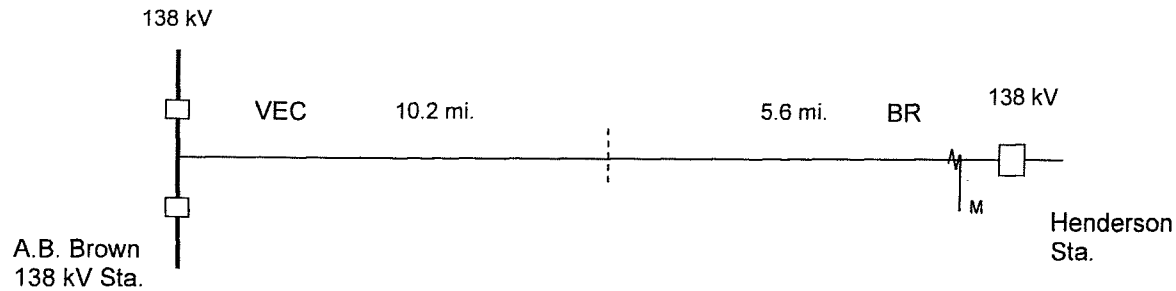
2.02 Big Rivers will make available to Vectren SCADA RTU data (accumulated and instantaneous data including Volts, Amps, MW, MVAR, MW-hours, breaker status and other mutually agreed to data) for monitoring the A.B. Brown - Reid 345 kV Interconnection Point.

Attachment for Response to KIUC 2-49(b)

Exhibit III

Figure 1

A.B. Brown-Henderson 138 kV Interconnection Point



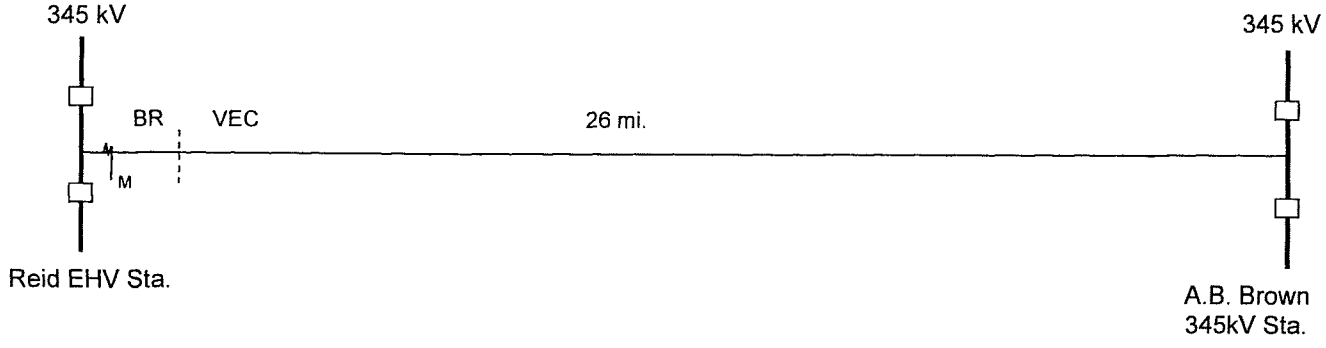
Note: BR means Big Rivers and
VEC means Vectren for this Exhibit

Attachment for Response to KIUC 2-49(b)

Exhibit III

Figure 2

A.B. Brown - Reid 345 kV Interconnection Point



Note: BR means Big Rivers and
VEC means Vectren for this Exhibit

Electronic Attachment(s) Produced Separately

File 12460.4
Original
Contract

RECEIVED
FEB 23 1974
BIG RIVERS
ELECTRIC CORPORATION

U. S. DEPARTMENT OF AGRICULTURE
RURAL ELECTRIFICATION ADMINISTRATION

REA BORROWER DESIGNATION Kentucky 62 Big Rivers

THE WITHIN Interconnection Agreement with Louisville Gas and Electric Company (LG&E).

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

FOR THE ADMINISTRATOR
George P. Herzog
Acting Administrator

DATED
FEB 21 1974

REA FORM 28a REV 5-73

INTERCONNECTION AGREEMENT

BETWEEN

LOUISVILLE GAS AND ELECTRIC COMPANY

AND

BIG RIVERS ELECTRIC CORPORATION

0.01 THIS AGREEMENT, dated as of this 21st day of December, 1973, between LOUISVILLE GAS AND ELECTRIC COMPANY (hereinafter called "Louisville"), a Kentucky corporation, and BIG RIVERS ELECTRIC CORPORATION (hereinafter called "Big Rivers"), an electric membership corporation incorporated in Kentucky,

W I T N E S S E T H:

0.02 WHEREAS, Louisville and Big Rivers each owns electric facilities and is engaged in the generation, transmission and sale of electric power and energy in the State of Kentucky; and

0.03 WHEREAS, the parties recognize that by interconnecting their electric systems in the manner hereinafter provided economies of operation may be realized and reliability of service may be improved, and

0.04 WHEREAS, the parties desire to interconnect their electric systems and to define the terms and conditions by which they will be governed in the interconnected operation of their said systems.

0.05 NOW, THEREFORE, in consideration of the premises and of the mutual covenants herein set forth, the parties hereto agree as follows:

ARTICLE 1

PROVISIONS FOR, AND CONTINUITY OF, INTERCONNECTED OPERATION

Interconnection Point

1.01 Big Rivers agrees to proceed with due diligence to construct a 138 KV transmission line extending from its Hardinsburg Station to Louisville's Cloverport Substation, and will exercise its best efforts to complete such construction by January 1, 1976.

1.02 Louisville agrees to proceed with due diligence to provide and construct at its Cloverport Substation the terminal facilities necessary to connect the 138 KV facilities at said Substation with Big Rivers' 138 KV transmission line, in accordance with good engineering design and practice, and will exercise its best efforts to complete such construction by January 1, 1976.

1.03 Upon completion of the facilities described in the two preceding sections, the parties agree to connect their respective systems, and to maintain such connection as provided for herein, at the point at Louisville's Cloverport Substation where the 138 KV facilities of Louisville are connected with the terminals of Big Rivers' 138 KV transmission line constructed pursuant to Section 1.01 above.

Synchronous Operation

1.04 The parties agree that during the term of this agreement their systems will, through the point of interconnection designated above, be continuously operated in parallel except in cases of interruption of such parallel operation due to necessary maintenance or due to causes beyond the control of either party hereto, or due to the necessity of an interruption of parallel operation in order that the consumers being directly served by either party may continue to receive adequate service from such party. If synchronous operation of the system through a particular line or lines becomes interrupted either manually or automatically because of reasons beyond the control of either party, the parties shall cooperate so as to remove the cause of such interruption as soon as practicable and restore such line or lines to normal operating condition. If the power or reactive flow over the interconnection facilities of either party becomes burdensome in the opinion of either party or exceeds the capacity of equipment installed in the system of either party hereto, the parties shall attempt to agree upon adequate corrective measures to eliminate or control such excessive power or reactive flow; provided, however, that in the event of such a burdensome situation existing, the party so burdened shall have the right, upon notice to the other party, to open one or all of the interconnections between the respective systems of the parties hereto.

Maintenance of Equipment

1.05 The parties hereto shall each keep, or shall cause to be kept, the lines and facilities, described in Article 1 hereof, that are located on their respective sides of the Interconnection Points in a suitable condition of repair at all times, each at its own expense, in order that said lines and facilities will operate in a reliable and satisfactory manner and in order that reduction in the capacity of said lines and facilities will be avoided to the extent practicable.

Capacity Responsibility

1.06 Each party shall provide sufficient capacity in its system, by installed generating capacity, firm purchase contracts, pooling arrangements or otherwise, so as to enable it to carry its peak load plus an adequate reserve. Each system shall provide sufficient amounts of spinning reserve capacity so as not to impose disproportionate demands upon the other for assistance in meeting the normal contingencies of power system operation.

ARTICLE 2

SERVICES TO BE RENDERED

2.01 It is the purpose of the parties hereto to seek and realize, on an equitable basis, all benefits practicable to be effected through coordination in the operation and development of their respective systems. It is understood by the parties that such benefits may be realized by them by carrying out under stated terms and conditions various interconnection services and transactions that may from time to time include:

(i) the furnishing of mutual emergency and standby assistance,

(ii) the interchange, sale, and purchase of energy to effect operating economies,

(iii) the coordination of maintenance schedules of generating and transmission facilities,

(iv) the sale and purchase of short-term electric power and energy available on the system of one party and needed on the system of the other.

In furtherance of such purpose the parties hereto shall create, and continue in functioning, an Operating Committee as provided under Article 7 hereof.

2.02 Inasmuch as the specific services to be rendered in furtherance of such purpose will vary from time to time during the duration of this agreement, and the terms and conditions applicable to such services may require modification from time to time, it is intended that such specific services and the terms and conditions applicable thereto will be set forth in service schedules from time to time mutually agreed upon between the parties. Such service schedules, until and unless changed, terminated, or supplemented, shall be those provided by Section 2.03 hereof.

2.03 The respective service schedules designated

Service Schedule A - Emergency Service

Service Schedule B - Interchange Power

Service Schedule C - Short Term Power

Service Schedule D - Facilities Rental, Cloverport Substation

which have been agreed upon between the parties hereto, are identified as Exhibits I, II, III, and IV respectively, to this agreement, are attached hereto and are hereby made a part hereof the same as if incorporated herein. It is contemplated by the parties that service schedules covering future agreements as to specific services will be similarly made a part of this agreement upon presentation and acceptance thereof.

ARTICLE 3

SERVICE CONDITIONS

Control of System Distribution

3.01 The parties hereto shall maintain and operate their respective systems so as to minimize, in accordance with sound operating practice, the likelihood of disturbance originating in either system which might cause impairment to the service of the system of the other party or of any system interconnected with the system of the other party.

Control of Kilovar Exchange

3.02 It is the intent that neither party hereto shall be obligated to deliver kilovars for the benefit of the other party; also that neither party shall be obligated to receive kilovars when to do so may introduce objectionable operating conditions on its system. The Operating Committee shall be responsible for the establishment from time to time of operating procedures and schedules, in respect of carrying kilovar loads by one system for the other in order to secure adequate service and economical use of the facilities of both systems and in respect of proper charges, if any, for the use of facilities carrying kilovar loads. In discharging such duties the Operating Committee shall recognize that in the transmission and delivery of power and energy hereunder the carrying of kilovar loads by either of the parties, in harmony with sound engineering principles of transmission operation with their systems interconnected, is subject to numerous variables contingent upon loading and operating conditions existing simultaneously on both of their systems. The operating procedures and schedules so set up by the Operating Committee shall be in accord with such principles and shall require each of the parties to carry kilovar loads at such times and in such amounts as will be equitable to both parties.

Inadvertent Flow

3.03 It is recognized by the parties that power and energy supplied and delivered under this agreement may be integrated with power and energy from generating facilities owned by others; that each party has or may hereafter have interconnection and exchange agreements with other power systems; that the flow of power and energy between the electric

systems of the parties hereto and the interconnected systems of others will, in part, be controlled by the physical and electrical characteristics of such systems; and that power and energy purchased, sold or exchanged under this agreement may flow through any or all of such interconnected systems. Such energy flows over their respective transmission facilities shall be permitted when such flows occur; subject, however, to the understanding that such flows shall not be of such magnitude or duration as to affect adversely or jeopardize the ability of the party over whose system such flows occur to render proper service to its customers, and to render or accept service to or from companies with which it now has or at any time hereafter it may have contractual arrangements to furnish, take, or interchange power or energy, or both. Furthermore, nothing herein shall obligate either party to wheel power or energy from or to a third party for the benefit of the other party.

Power and Energy Accounting

3.04 The parties recognize that energy flows as described in the preceding section, except for such amounts of electrical losses as may be incurred because of such energy flows, is the simultaneous acceptance and delivery of like amounts of power and energy by and from the system of the party over whose system such energy flows occur. Power and energy associated with such flows, including electrical losses associated therewith, shall be accounted for each clock-hour. Proper consideration to such electrical losses will be in accordance with the manner agreed upon by the Operating Committee. It is understood by the parties, however, that such electrical losses resulting from energy flows, to be taken as losses over and above the losses prevailing under basic conditions agreed upon by the parties, shall be supplied simultaneously by the party responsible for such flows. The parties have agreed that initially such basic conditions will be established as those that exist when the schedules net delivery between the systems of the parties, and between their respective systems and the systems of other interconnected companies, is zero kilowatts. It is further understood that, from time to time, conditions may require the establishment of different basic conditions for such purpose. Either party by written notice given to the other party may call for a prompt re-examination and reconsideration of matters pertinent to the establishment of said basic conditions, whenever such re-examination appears to be warranted, and the parties will thereupon agree to effect such changes in the basic conditions, if any, that will equitably compensate the parties for such losses. All accounting and billing related to inadvertent flows shall be based on methods determined by the Operating Committee, which shall take into consideration arrangements with other interconnected systems. Any cash settlements associated therewith shall be based on out-of-pocket costs of the supplying party, as set forth in Article 11 hereof.

Control of Unscheduled Power Deliveries

3.05 The parties hereto shall exercise due diligence and foresight in carrying out all matters related to the providing and operating of

their respective electric power resources so as to minimize to the extent practicable deviations between actual and scheduled deliveries of electric power and energy between their systems and systems of other interconnected companies. The parties shall provide and install on their respective systems such communication and telemetering facilities as are essential to so minimizing such deviations; and, in developing and executing operating procedures that will enable the parties to avoid to the extent practicable deviations from scheduled deliveries, shall fully cooperate with each other and with third parties whose systems are either directly or indirectly interconnected with the systems of the parties and who of necessity together with the parties must unify their efforts cooperatively to achieve effective and efficient interconnected operation.

ARTICLE 4

DELIVERY POINTS, METERING POINTS, AND METERING

Delivery Points

4.01 All electric energy delivered under this agreement shall be of the character commonly known as three-phase sixty-hertz energy, and shall be considered as being delivered at the Interconnection Point, and at the voltage as designated in Section 1.03 hereof.

Metering Points

4.02 Electric power and energy supplied and delivered under this agreement shall be measured by:

(i) suitable metering equipment installed, owned and maintained by Louisville at or near the delivery points specified in Section 4.01 above.

(ii) suitable metering equipment installed and maintained under such ownership at such other locations as may be agreed upon by the parties.

Scheduling of Deliveries and Receipts

4.03 All scheduled power and energy delivered by either party hereto shall be the quantities previously determined and concurred in by the Load Dispatchers of the respective parties in accordance with the various categories of transactions provided for herein. Billings and/or settlements therefor shall be made on the basis of such schedules.

Metering Equipment

4.04 Suitable metering equipment at the metering points as provided in Section 4.02 hereof shall include electric meters, potential and current transformers, telemetering equipment, and such

other appurtenances as shall be necessary to provide for each direction of flow appropriate recordings, as determined by the Operating Committee, of kilowatts, kilovars, and kilowatt-hours.

4.05 Measurements of electric energy for the purpose of effecting settlements under this agreement shall be made by standard types of electric meters installed and maintained, unless otherwise provided for in this agreement, by the owner at the metering points as provided under Section 4.02 above. The timing devices of all meters having such devices shall be maintained in time synchronism as closely as practicable. The meters shall be sealed and the seals shall be broken only upon occasions when the meters are to be tested or adjusted. For the purpose of checking the records of the metering equipment installed by one of the parties hereto as hereinabove provided, the other party hereto shall have the right to install check metering equipment at the aforesaid metering points. Metering equipment so installed by one party on the premises of another party, unless otherwise provided for in this agreement, shall be owned and maintained by the party owning such metering equipment. Upon termination of this agreement the party owning such metering equipment shall remove it from the premises of the other party.

4.06 All meters shall be read on or about the first day of each calendar month.

4.07 The aforesaid metering equipment shall be tested by the owner at suitable intervals of not more than twelve months, and its accuracy of registration maintained in accordance with good practice. On request of either party hereto, a special test may be made at the expense of the party requesting such special test. Representatives of both parties shall be afforded opportunity to be present at all routine or special tests upon occasions when any readings, for purposes of settlements hereunder, are taken from meters not bearing an automatic record.

4.08 If at any test of metering equipment an inaccuracy shall be disclosed exceeding two percent, the account between the parties hereto for service theretofore delivered shall be adjusted to correct for the inaccuracy disclosed over the shorter of the following two periods: (1) for the thirty-day period immediately preceding the day of the test or (2) for the period that such inaccuracy may be determined to have existed. Should the metering equipment as provided for under Section 4.04 hereof at any time fail to register, the electric power and energy delivered shall be determined from the check meters, if installed, or otherwise shall be determined from the best available data.

ARTICLE 5

RECORDS AND STATEMENTS

Records

5.01 In addition to records of the metering provided for in Article 4

hereof, the parties hereto shall keep such other records as may be needed to afford a clear history of the various deliveries of electric energy made by one party to the other. In maintaining such records, the parties shall effect such segregations and allocations of demands and electric energy delivered into classes representing the various services and conditions as may be needed in connection with settlements under this agreement. A summary of transactions shall be exchanged and agreed to between the parties monthly in such form and manner as may be agreed on by the Operating Committee.

Statements

5.02 As promptly as practicable, but not more than ten days, after the end of each calendar month, Louisville shall cause to be prepared a statement setting forth the electric power and energy transactions between the parties during such month in such detail and with such segregations as may be needed for operating records or for settlements under the provisions of this agreement.

ARTICLE 6

BILLING AND PAYMENTS

6.01 All bills for amounts owed by one party hereto to the other shall be due and payable on the tenth day following receipt of bill. Interest on unpaid amounts shall accrue at the rate of six per cent per annum from the date due until the date upon which payment is made. In the event a party wishes to contest a portion of a billed amount, such party shall pay the portion not contested; and, if such payment is timely made, interest shall not accrue on the paid portion while resolution of contested amounts is pending. Unless otherwise agreed upon, a calendar month shall be the standard monthly period for the purpose of settlements under this agreement. Where amounts are due from both parties to the other, bills shall wherever possible be stated in the net amount.

ARTICLE 7

OPERATING COMMITTEE

7.01 To coordinate the operation of their respective generating, transmission, and substation facilities, in order that the advantages to be derived hereunder may be realized by the parties hereto to the fullest practicable extent, the parties shall establish a committee of authorized representatives to be known as the Operating Committee. Each of the parties shall designate in writing delivered to the other party, the person who is to act as its representative on said committee (and the person or persons who may serve as alternate whenever such representative is unable to act). Such representatives and alternate or alternates shall each be persons familiar with the generating, transmission, and substation facilities of the system of the party by which he has been so designated, and each shall be fully authorized (1) to cooperate with the other representative (or alternate) and (2) from time to time as need arises, subject to the declared intentions of the parties herein set forth and to the terms hereof and the terms of any other agreements then

in effect between the parties, to determine and agree upon the following:

7.011 All matters pertaining to the coordination of maintenance of the generating and transmission facilities of the parties.

7.012 All matters pertaining to the control of time, frequency, energy flow, kilovar exchange, power factor, voltage, and other similar matters bearing upon the satisfactory synchronous operation of the systems of the parties.

7.013 Such other matters not specifically provided for herein upon which cooperation, coordination, and agreement as to quantity, time, method, terms and conditions are necessary in order that the operation of the systems of the parties may be coordinated to the end that the potential savings will be realized to the fullest practicable extent that is agreed upon by the parties.

7.02 For the purpose of inspection and reading of meters, checking of records, and all other pertinent matters, said representatives and their alternates shall have the right of entry to all property of the parties hereto used in connection with the performance of this agreement.

ARTICLE 8

CONTINUITY OF SERVICE

8.01 Each party hereto shall exercise due diligence and reasonable care and foresight to maintain continuity of service in the delivery and receipt of energy as provided under this agreement, but neither party shall be considered to be in default in respect of any obligation hereunder if prevented from fulfilling such obligation by reason of uncontrollable forces. The term uncontrollable forces shall be deemed for the purpose of this agreement to mean earthquake, storm, lightning, flood, backwater caused by flood, fire, epidemic, accident, failure of facilities, war, riot, civil disturbances, strike, labor disturbances, restraint by court or public authority, or other similar or dissimilar causes beyond the control of the party affected which causes such party could not have avoided by exercise of due diligence and reasonable care. Any party unable to fulfill any obligation by reason of uncontrollable forces shall exercise due diligence to remove such disability with reasonable dispatch.

ARTICLE 9

EFFECTIVE DATE AND TERMINATION

9.01 This agreement shall become effective upon its execution by the parties and its approval by the Administrator of REA and all state and federal regulatory bodies having jurisdiction thereof, and shall continue in effect until December 31, 1985, and thereafter unless or until terminated

on such date or on any subsequent December 31st by either party giving to the other at least 24 months notice of termination prior to the intended termination date.

ARTICLE 10

ARBITRATION

10.01 Any controversy, claim, counterclaim, defense, dispute, difference or misunderstanding arising out of or relating to this Agreement, or the performance thereof, or the breach thereof, including, without limitation (1) any controversy that might be the subject of an action between the parties, (2) any question of operating practice involved in the deliveries of power or energy herein provided for, (3) any question of fact involved in the application of the provisions of this Agreement, or (4) the interpretation of any provision of this Agreement shall be settled by negotiation between the parties hereto, but in the event of failure of negotiations, then by arbitration as herein set forth. An offer of such submission to arbitration shall be a condition precedent to any right to institute proceedings at law or in equity concerning such matter.

10.02 Either party hereto may, by written notice to the other within fifteen days after the failure of the parties to settle a controversy by negotiation, call for the appointment of a board of arbitrators skilled with respect to matters of the character involved in the controversy, naming one arbitrator in such notice. The other party shall, within ten days after the receipt of such call, appoint a second arbitrator, and the two so appointed shall choose and appoint a third. In case such other party fails to appoint an arbitrator within said ten days, or in case the two so appointed fail for ten days to agree upon and appoint a third, the party which called for arbitration may, upon five days' written notice served on the other party, apply to a Kentucky Circuit Court that has jurisdiction over the other party for appointment of the second or third arbitrator, as the case may be.

10.03 Upon the appointment of three arbitrators as herein provided, such arbitrators shall, within fifteen days or such other period of time as the parties or the aforesaid Circuit Court shall decide, hold an arbitration hearing within the County wherein the party which called for arbitration has its principal place of business. At the hearing, the rules of evidence of the Commonwealth of Kentucky, and the procedures set out in Chapter 417, Kentucky Revised Statutes, shall apply. The three arbitrators shall allow each party to present its case, evidence and witnesses, if any, in the presence of the other party, and shall render their award within a reasonable time. The award of the majority of the arbitrators shall be binding on the parties hereto, and said award may be enforced by any court having jurisdiction, as provided in Chapter 417, Kentucky Revised Statutes.

10.04 Each party shall pay for the services and expenses of the arbi-

trator appointed by or for it and all other costs incurred in connection with the arbitration shall be paid in equal parts by the parties hereto, unless the award shall specify a different division of the costs.

ARTICLE 11

DEFINITION OF OUT-OF-POCKET COST

11.01 Wherever the term "out-of-pocket cost" is used in this Agreement, or in any of the service schedules which are or may be made a part hereof, in connection with the furnishing of energy by either party hereto, it shall have the following meaning: Out-of-pocket cost of generating energy in the generating stations of the system of either party consists of fuel, taxes, and other expenses which are incurred by the supplying system directly by reason of its generation of such energy and which otherwise would not have been incurred by such system. Such operating expenses, under usual circumstances, will include the incremental production expense incurred in the production of the energy so furnished. Incremental production expense associated with the production of such energy will be influenced by the class of generating station used for such purpose. If the station used is normally operating and carrying load, the incremental expense will be the fuel expense plus appropriate allowances for maintenance and for incremental operating labor. The appropriate per kilowatt-hour allowance for maintenance under such circumstances will be one-half of the weighted average per kilowatt-hour cost (expressed in mills per kilowatt-hour of net generation) incurred at such station for maintenance during a representative period such as an annual period next preceding the month that such production occurred. If the station or part thereof used is normally held in reserve as standby, all expense incurred that is in excess of the expense that would have been incurred for standby operation of such station or part thereof will be considered incremental expense. Out-of-pocket cost of energy purchased from a source outside the system of the supplying party consists of the total amount paid therefor by the supplying party which otherwise would not have been paid by such party. Tax expenses will be the expenses that are payable as taxes either in connection with the sale or production of such energy.

ARTICLE 12

LIABILITY

12.01 Each party hereto shall save and hold the other party hereto free and harmless from and against liability, loss, damage and expense arising from or incident to injury or damage to persons or property occasioned by or in connection with its own facilities or the production or flow of electric energy by or through such facilities except when such injury or damage is due to the negligence of such other party.

ARTICLE 13

TAXES

13.01 If at any time during the term hereof there should be levied or

assessed against either of the parties hereto any direct tax by any taxing authority on the capacity or energy (or both) generated, purchased, sold, transmitted, interchanged or exchanged by it, which tax is in addition to or different from the forms of such direct taxes as are now being levied or assessed, and such direct tax results in increasing the cost of either or both the parties hereto in carrying out the provisions of this agreement, then such increase shall be made in the charges for capacity or energy (or both) furnished by one party to the other hereunder as is necessary in order to make adequate and equitable allowances for such tax.

ARTICLE 14

NOTICES

14.01 Except as herein otherwise provided, any notice which may be given to or made upon either party hereto by the other party hereto under any of the provisions of this agreement, shall be in writing unless it is otherwise specifically provided herein, and shall be treated as duly delivered when the same is either (a) personally delivered to the president of Louisville, in the case of a notice to be given Louisville, or personally delivered to the manager of Big Rivers, in the case of a notice to be given Big Rivers, or (b) deposited in the United States mail, postage prepaid and properly addressed to the above parties.

14.02 Any notice, request or demand pertaining to matters of an operating nature may be delivered by ordinary mail, messenger, telephone, telegraph, or verbally by and to appropriate operating personnel; and, in any particular instance if either party hereto so requests, shall be confirmed in writing as soon as practicable thereafter.

ARTICLE 15

REGULATORY AUTHORITIES

15.01 This agreement is made subject to the jursidiction of any governmental authority or authorities having jurisdiction in the premises and if any of the terms and conditions hereof are altered or made impossible of performance by the adjudication of any such governmental authority, and the parties hereto are unable to agree upon a modification of such terms and conditions, then in such event neither party shall be liable to the other for failure thereafter to comply with such terms and conditions.

15.02 A seller's obligation to deliver power or energy under any of the service schedules attached hereto shall be contingent on its ability to generate energy for sale to the purchaser in compliance with Federal, State or Local regulations, orders or directives, including, but not limited to, those pertaining to air pollution control.

ARTICLE 16

WAIVERS

16.01 Any waiver at any time by either party hereto of its rights

with respect to a default under this agreement, or with respect to any other matter arising in connection with this agreement shall not be deemed a waiver with respect to any subsequent default or matter. Any delay, short of the statutory period of limitation, in asserting or enforcing any right under this agreement, shall not be deemed a waiver of such right.

ARTICLE 17

ENTIRE AGREEMENT CONTAINED HEREIN

17.01 This agreement contains the entire agreement between the parties hereto in respect of the subject matter hereof, and there are no other understandings or agreements between the parties hereto in respect thereof.

ARTICLE 18

ASSIGNMENT

18.01 This agreement shall inure to and bind the respective successors and assigns of the parties hereto, but the assignment thereof by either party shall not relieve such party, without the written consent of the other party, of any obligation to supply, or to take and pay for, as the case may be, the services here contracted for.

ARTICLE 19

APPLICABILITY OF LAW

19.01 To the extent not prohibited by the laws of the United States of America, this Agreement shall be governed by, and construed according to, the laws of the Commonwealth of Kentucky.

20.01 IN WITNESS WHEREOF the parties hereto have caused this agreement to be executed by their duly authorized officers and their respective corporated seals to be hereunto affixed as of the date first above mentioned.

LOUISVILLE GAS AND ELECTRIC COMPANY

ATTEST:

By _____
President

_____
Secretary

BIG RIVERS ELECTRIC CORPORATION

ATTEST:

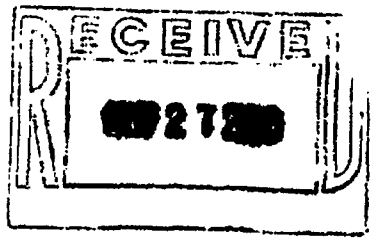
By _____
President

original - D. Hill
Feb. 132.04

Attachment for Response to KIUC 2-49(b)

Southern Illinois Power Cooperative

11543 Lake of Egypt Road
Marion, IL 62959
(618) 964-1448 Fax (618) 964-1867



November 20, 2000

Mr. David G. Crockett, P.E.
Big Rivers Electric Corporation
Manager of Engineering & Operations
201 Third Street, P.O. Box 24
Henderson, KY 42419-0024

Re: 1981 Transmission Line Agreement

Dear Mr. Crockett:

I have enclosed one executed copy of the clarification document regarding the 1981 Transmission Line Agreement for your files.

If you have any questions, please contact me.

Very truly yours,

Ted Hilmes
Systems Department Manager

TH/bks

Enclosure

1 of 2

Attachment for Response to KIUC 2-49(b)

Clarification Regarding February 1, 1981 Transmission Line Agreement

Pursuant to recent discussions between representatives of Big Rivers Electric Corporation ("Big Rivers") and Southern Illinois Power Cooperative ("Southern Illinois"), we are signing this letter of clarification between Big Rivers and Southern Illinois concerning the 1981 Transmission Line Agreement.

Many changes in the wholesale market for electricity have occurred since Big Rivers and Southern Illinois entered into the 1981 Transmission Line Agreement, including the development of new markets and power delivery options not contemplated by the 1981 Transmission Line Agreement. In order to avoid confusion regarding the operation of that agreement, which both parties agree should remain in effect without amendment; this letter clarifies how the parties intend that agreement to operate going forward.

Section 4 of the 1981 Transmission Line Agreement specifies Southern Illinois' rights to use excess capacity in the Ohio River to Barkley Dam 161 kV transmission line covered by the 1981 Transmission Line Agreement. That section states that Big Rivers will furnish Southern Illinois with use of the line "so as to afford [Southern Illinois] scheduling of electric power and energy with S.E.P.A. and T.V.A. to, from or through said Kentucky line from the said Ohio River crossing to the Barkley Dam terminal." Given this limitation on use, the agreement shall be interpreted by Big Rivers and Southern Illinois as granting Southern Illinois the ability to use, without additional charge, the line's transmission capacity in excess of Big Rivers' internal uses only for:

1. The scheduling of excess energy from its own resources over this line. Excess energy will only come from Southern Illinois generation resources or firm purchases backed up with accredited capacity needed to meet Southern Illinois' peak requirements.

2. The scheduling of deficit energy that is needed for internal Southern Illinois load. Deficit energy is the difference between Southern Illinois load and Southern Illinois firm available resources. This energy will not be resold outside the Southern Illinois system.

3. Transmission of Southern Illinois allocated S.E.P.A. energy into the Southern Illinois system.

Although Big Rivers will reserve all of the excess capacity in the line in question for use by Southern Illinois under all of the circumstances described in the three points above, Southern Illinois shall make additional compensation to Big Rivers at Big Rivers' then applicable Open Access Transmission Tariff transmission rates for any other use. Other use includes scheduling of electric power and energy with S.E.P.A. and T.V.A. to, from or through said Kentucky line that is not excess from Southern Illinois resources or needed for Southern Illinois member load.

11-20-00
Tim Reeves date
Southern Illinois
Power Cooperative

11/10/00
Michael H. Core date
Big Rivers Electric
Corporation

END

TRANSMISSION LINE AGREEMENT

THIS AGREEMENT, made and entered into this 1st day of February, 1981, by and between Southern Illinois Power Cooperative, an Illinois Corporation, of Marion, Illinois, hereinafter referred to as "S.I.P.C.", and Big Rivers Rural Electric Corporation, a Kentucky Corporation, of Henderson, Kentucky, hereinafter referred to as "Big Rivers";

WITNESSETH:

WHEREAS, the parties to this Agreement are each engaged in the production and sale of electric power and energy, and own and operate their respective generation and transmission facilities, selling such electric power and energy to their own respective customers, and,

WHEREAS, the above parties entered into a "Cost Sharing Agreement", dated May 1, 1968, relative to the construction of a 161 KV electric transmission river crossing across the Ohio River near Bay City, Illinois, which was constructed, and,

WHEREAS, S.I.P.C. built its own 161 KV electric transmission line to the said river crossing, and Big Rivers built its own 161 KV electric transmission line from Barkley Dam to the said river crossing, hereinafter referred to as the "Kentucky line", whereby the parties hereto have heretofore, since the construction of said lines and river crossing, been interconnected through said 161 KV electric transmission line, and,

WHEREAS, heretofore, the parties hereto have recognized the said transmission line as a joint-use transmission line, and,

WHEREAS, the parties hereto have, because of their respective circumstances now existing, determined that it is for the best interest of the parties to enter into this Agreement whereby S.I.P.C. formally leases from Big Rivers the right to use the said Ohio River transmission line crossing and the 161 KV electric transmission line from the said river crossing to its terminal at Barkley Dam, Kentucky, for the exclusive use of S.I.P.C. except,

of course, for the use to be made of said line by Big Rivers for its own internal system use, as hereinafter stated.

WHEREFORE, in consideration of the mutual covenants and agreements herein expressed, the parties hereto agree as follows:

S.I.P.C. AGREES:

1. To pay, on the 1st of each month hereafter, commencing April 1, 1981, to Big Rivers the sum of Two Thousand Dollars ($2,000.00) as rental of said Kentucky line.

2. To maintain its own 161 KV electric transmission line north of the said river crossing in the State of Illinois for the use of Big Rivers under the provisions of the existing K.I.I. pool agreement dated April 1, 1968, as amended.

3. To continue to recognize and perform its obligations under the "Cost Sharing Agreement" hereinabove referred to, dated May 1, 1968, relative to the river crossing of said 161 KV electric transmission line.

4. To recognize and cooperate with Big Rivers in the use of the said Kentucky line to serve its own internal loads.

5. To hold Big Rivers harmless from any claims or actions of third parties or entities that might arise by reason of the use of said Kentucky line by S.I.P.C. under the provisions of this contract.

BIG RIVERS AGREES:

1. To continue to recognize its contractual obligations under the "Cost Sharing Agreement" dated May 1, 1968, relative to the Ohio River crossing of said electric transmission line.

2. To maintain and operate the said Kentucky line, pay taxes, insurance and all costs associated with the ownership of said transmission line.

3. To give S.I.P.C. exclusive right to use said transmission line and Ohio River crossing from the said river crossing at Bay City, Illinois, to the Barkley Dam terminal in Kentucky,

thereby leasing to S.I.P.C. all capacities of said transmission line not used by Big Rivers for its own internal loads. Big Rivers shall not, during the term of this contract, contract for the use of said line or any capacity therein outside of the internal loads of Big Rivers except those provided for under the April 1, 1968 KII Pool Agreement, as amended.

4. To furnish to S.I.P.C. use of said line, as hereinabove stated, so as to afford S.I.P.C. scheduling of electric power and energy with S.E.P.A. and T.V.A. to, from or through said Kentucky line from the said Ohio River crossing to the Barkley Dam terminal.

5. To permit the unrestricted use of said Kentucky line for carrier circuitry, as needed, including telemetering, digital analogs, etc., and the right to install said communications equipment as shall be necessary to accommodate S.I.P.C. in the use of said Kentucky line.

6. To cooperate with S.I.P.C. in its use of said communications and control systems on said Kentucky line.

7. To warrant that it is the owner of said Kentucky line, with full rights to lease the same, giving consideration to the fact that the said line is encumbered to the Rural Electrification Administration.

8. To hold the lessee, S.I.P.C., harmless from any and all claims and actions, at law or otherwise, of third parties or entities that arise out of the ownership of said electric transmission line during the term of this lease.

IT IS MUTUALLY AGREED:

1. That the term of this contract shall be perpetual, or until such time as S.I.P.C. shall no longer use said Kentucky line, and in such an event, S.I.P.C. shall give to Big Rivers 12 months' notice of its intention to terminate this contract.

2. Each of the parties hereto shall exercise every effort to cooperate with the other in affording the rights of each of the parties expressed in this agreement, as well as the joint

use of the said entire transmission line in Illinois and in Kentucky under the provisions of the K.I.I. pool agreement hereinabove referred to.

IN WITNESS WHEREOF, the parties hereto, pursuant to proper corporate authority of each of their respective boards of directors, have executed this agreement as of the day and year first above written.

SOUTHERN ILLINOIS POWER COOPERATIVE

BY: _____
President

ATTEST:

_____
Secretary

(Corp. Seal)

BIG RIVERS RURAL ELECTRIC CORPORATION

BY: _____
President

ATTEST:

_____
Secretary

(Corp. Seal)

U. S. DEPARTMENT OF AGRICULTURE
RURAL ELECTRIFICATION ADMINISTRATION

Kentucky 62 Big Rivers
Indiana 106 Statewide
REA BORROWER DESIGNATION Illinois 50 Cairo

THE WITHIN Interconnection Agreement dated
between Big Rivers RECC, the Hoosier Energy
Ind. Statewide Rural Elec. Coop., Inc., the
Power Coop., & the City of Henderson

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

Richard H. Wood
FOR THE ADMINISTRATOR

DATED
APR 3 0 1968

REA FORM 28a REV. 8-60

INTERCONNECTION AGREEMENT

INDIANA STATEWIDE RURAL ELECTRIC, INC.
HOOSIER ENERGY DIVISION

SOUTHERN ILLINOIS POWER COOPERATIVE

BIG RIVERS RURAL ELECTRIC COOPERATIVE CORPORATION

CITY OF HENDERSON, KENTUCKY
UTILITY COMMISSION

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INTERCONNECTION AGREEMENT

THIS AGREEMENT made and entered into as of the 1st day of April, 1968 by and between INDIANA STATEWIDE RURAL ELECTRIC, INC., an Indiana corporation, acting through its HOOSIER ENERGY DIVISION, with principal office at Bloomington, Indiana, hereinafter referred to as "Hoosier"; SOUTHERN ILLINOIS POWER COOPERATIVE, an Illinois corporation, with principal office at Marion, Illinois, hereinafter referred to as "Southern Illinois"; BIG RIVERS RURAL ELECTRIC COOPERATIVE CORPORATION, a Kentucky corporation with principal office at Henderson, Kentucky, hereinafter referred to as "Big Rivers"; and CITY OF HENDERSON, KENTUCKY, a municipal corporation of the third class, acting through its UTILITY COMMISSION, with office at Henderson, Henderson County, Kentucky, hereinafter referred to as "Henderson".

WITNESSETH:

STIPULATION: The parties to this Agreement are each engaged in the production and sale of electric power and energy, owning and operating their respective production facilities and selling such power and energy to their own respective consumers. In order to obtain maximum economies in the production of power and energy, to effect the most efficient utilization of their existing and future production and transmission facilities, and to assure maximum reliability of service to their respective consumers, the parties to this Agreement desire to interconnect their respective systems, thereby providing for the sharing of generation and transmission facilities, the furnishing and obtaining of surplus power and energy, and

providing for mutual assistance in the operation and maintenance of their respective systems.

Hoosier, Southern Illinois and Big Rivers are presently operating under the provisions of an Interconnection Agreement dated June 25, 1965. Henderson is presently operating under similar Interconnection Agreement with Big Rivers dated September 1 , 1965. It is the desire and intention of the parties that all of said existing agreements as supplemented and amended shall be terminated and superceded at the time this Agreement is accepted and entered into by all of the parties hereto.

NOW, THEREFORE, in consideration of the premises, and of the mutual covenants and agreements hereinafter made, IT IS HEREBY MUTUALLY STIPULATED, COVENANTED AND AGREED by and between the parties, as follows:

ARTICLE 1: DEFINITIONS

As used in this Agreement, unless the contex requires otherwise:

1.01. "System" shall mean the generation facilities, transmission facilities, and other related facilities owned, leased or otherwise available to each party to this Agreement for its generation, transmission and receipt of power and energy under this Agreement.

1.02. "Transmission System" shall mean the transmission facilities, associated switching and substations, and control and communication facilities owned, leased or otherwise controlled by each of the parties to this Agreement, and which would affect the operation of the pool system.

1.03. "Pool System" or "Pool" shall mean the Combined Systems of all of the parties to this Agreement.

1.04. "Generating Capacity" shall mean the demonstrated 4-hour unit or units capability at the time of annual pool system peak, less the capacity required to operate the auxiliaries of the unit or units included in the 4-hour rating test.

1.05. "Certified Pool Capacity" shall mean the total capacity available to the pool system, including the Generating Capacities of the parties to this Agreement plus any purchases of capacity from others not a party to this Agreement (when such Generating Capacities and purchases are recommended by the Operating Committee and approved by the parties to this Agreement), but not including capacity sales or purchases between the parties to this Agreement.

1.06. "Annual System Peak" as applicable to each party's system, shall mean the maximum integrated hourly kilowatt input to that party's system, during the year, for service to its consumers and firm sales to others not a party to this Agreement, but not including sales to other parties to this Agreement.

1.07. "Annual Pool System Peak" shall mean the maximum combined hourly kilowatt input to the pool system during the year, for service to the parties' consumers and firm sales to others not parties to this Agreement, but not including sales between or among the parties to this Agreement.

1.08. "System Capacity Requirement" shall mean the amount of capacity required to be provided to the pool by each party to this Agreement and shall be determined as provided in paragraph 2.07.

1.09. "Spinning reserve capacity" shall mean the amount of unloaded generating capacity which is spinning in synchronism with the pool system, and which is capable for promptly picking up load in that amount in the event of an emergency.

1.10. "Standby Capacity" shall mean power and energy available for emergencies and scheduled maintenance outages from systems of others not parties to this Agreement.

1.11. "Equalization Power" shall mean that portion of the Certified Pool Capacity available on a party's system from time to time which is in excess of such party's system capacity requirement.

1.12. "Economy Energy" shall mean energy which can be supplied, at a saving, from one party's generating facilities not otherwise being fully utilized, and utilized by another party to reduce generation from units or sources having higher operating costs, or to avoid starting or operating generating units.

1.13. "Emergency" shall mean a condition resulting in the inability of a party to supply all or a portion of its requirements due to an unscheduled outage of generation or transmission facilities.

1.14. "Emergency Power and Energy" shall mean power and energy provided to a party during an emergency involving that party's system.

1.15. "Annual" or "Year" shall mean a period of 12 consecutive months commencing on the first day of November and ending on the thirty-first day of October of the following calendar year.

1.16. "Operating Committee" shall mean the committee appointed by the parties in accordance with sub-article 2.10 of this Agreement.

1.17. "Uncontrollable Force" shall mean any force which is not within the control of any of the parties hereto, and which by exercise of due diligence and foresight could not reasonably have been avoided, including, but not limited to, failure of facilities, failure of water supply, flood, earthquake, storm, lightning, fire, epidemic, war, riot, civil disturbance, labor disturbance, sabotage or restraint or order by court or public authority having jurisdiction,

1.18. "Billing Period" or "Month" shall mean a period of time beginning on the first day and extending through the last day of each calendar month.

1.19 "Net Balance in Money" shall mean the net compensation due from one party to another for any particular billing period after properly debiting and crediting charges as provided in this Agreement.

ARTICLE 2: INTERCONNECTED OPERATIONS

2.01. PURPOSE OF INTERCONNECTION

The parties agree:

(a) To jointly plan and coordinate the addition of generation facilities and transmission facilities to meet the future requirements of the pool system under the terms of this contract in the optimum manner.

(b) To interconnect their transmission systems so as to constitute an effective integrated system.

(c) To furnish emergency assistance.

(d) To coordinate maintenance scheduling of generation and transmission facilities.

(e) To interchange, sell and purchase energy to effect operating economies.

(f) To transfer energy through the transmission systems of one or more parties for the benefit of other party or parties.

(g) To sell and purchase Equalization Power and associated energy available on the systems of other party or parties

(h) To do such other things as may be reasonably necessary or convenient to provide for the interconnected system the maximum assurance of an adequate and reliable supply of power and energy at minimum costs.

2.02 INTERCONNECTED SYSTEM

Each of the parties hereto shall at all times during the term of this contract cooperate in the establishment, maintenance and operation of their respective systems to assure maximum economy and reliability of the pool system. Additional facilities necessary to maintain required pool capacity shall be provided as mutually agreed upon by the parties.

2.03. POINTS OF INTERCONNECTION

The points of interconnection shall be at or near locations to be determined by the Operating Committee and as mutually agreed upon by the parties during the term of this contract, except that the initial points of interconnection and the transmission facilities either in existence or agreed to be built by each of the parties to extend their systems to such initial points of interconnection shall be as described in Exhibit A which is attached here to and made a part hereof. Immediately after the effective date of this Agreement the parties shall proceed as soon as reasonably practicable to construct the transmission facilities necessary to connect their systems at the initial points of interconnection as provided in said Exhibit A.

2.04. POINTS AND CHARACTER OF DELIVERY

All electric power and energy exchanged between the parties hereto at the points of interconnection shall nominally be delivered and received as 3-phase alternating current, at a frequency of approximately 60 cycles

per second, and at the nominal voltage at such points of interconnection.

2.05. OPERATION OF SYSTEM

The parties shall, to the maximum extent possible, operate their systems in parallel at all times, and coordinate their operations to assure maximum continuity of service to their respective consumers, and with relation thereto shall cooperate with one another in the establishment of schedules for operation and maintenance of equipment, and shall cooperate in the coordination of relay protection, frequency and load control and communications. Each party to this Agreement shall maintain and operate all facilities owned and constructed by it in such a way as to minimize interruptions to service, and so as not to unduly burden or adversely affect the systems of the other parties.

2.06. GENERATING CAPACITY

Generating capacity shall be determined by the Operating Committee at the effective date of this contract and from time to time thereafter as changes in the pool system and the systems of the parties may warrant.

2.07. ANNUAL SYSTEM CAPACITY REQUIREMENT

Each party's annual System Capacity Requirement shall be determined by the Operating Committee by multiplying the Annual System Peak of such party by a fraction, the numerator of which shall be the Certified Pool Capacity and the denominator of which shall be the sum of the Annual System Peaks of the parties to this Agreement.

The Operating Committee shall, in September of each year, prepare estimates of the annual System Peak of each Party

for the next four ensuing years, showing in detail that portion of the Certified Pool Capacity available to each party and listing the capacity deficiencies or excesses available toward meeting each party's annual System Capacity Requirement. The parties having estimated capacity deficiencies in their annual System Capacity Requirement shall, for at least 4 years in advance, contract by supplement hereto to purchase power to meet their estimated capacity deficiencies from the parties having excess capacity. In such agreements and adjustments thereto, the excess capacity of the parties having excess capacity shall be allocated to each party having a deficiency in proportion to that party's deficiency to the total deficiency. In the event the Annual System Peak of any party's system exceeds the estimated Annual System Peak reflected in the then effective contract supplements for purchase or sale of such deficiency or excess capacity, then the Annual System Capacity Requirement of all the Parties shall be adjusted without additional agreements to reflect such party's excess of Annual System Peak over the Estimated Annual System Peak, and appropriate adjustment made in billing therefor, with such adjustment to be applied equally over the succeeding 12 months. Such capacity sales and purchases shall be considered as equalization power and shall be subject to the rates, terms and conditions of Article 4 hereof and Article 9 hereof.

2.08 PROVIDING OF SYSTEM CAPACITY REQUIREMENT

Each party shall maintain at all times sufficient capacity to supply its own System Capacity Requirement. Such party's System Capacity Requirement shall be provided for by its Generating Capacity as defined in sub-article 1.04 above, or any additions of Generating Capacity thereto, or by purchasing capacity from the other parties to this Agreement or from

other sources. Capacity purchases from other than parties to this Agreement may be made only when there are insufficient capacities available from the parties to this Agreement as determined by the Operating Committee in accordance with sub-article 2.07.

Several of the parties hereto have entered into agreements with Southeastern Power Administration (SEPA) under which SEPA agrees to furnish standby capacity to said parties. The Operating Committee shall determine the effective standby capacity available to the pool system from each of said parties under the terms of their agreements with SEPA. The amount of SEPA's standby capacity to be considered available from each such party to meet its system capacity requirement and spinning reserve requirement shall be determined by multiplying the total effective standby capacity available from SEPA under the terms of such agreements by a fraction, the numerator of which is the Annual System Peak of such party, and the denominator of which is the sum of the Annual System Peak of all of the parties having such agreements with SEPA. The SEPA contract standby demand charges under each agreement shall be totalled, and each party having such SEPA agreements shall be charged with its proportionate share thereof in accordance with the formula stated in this sub-paragraph. In making the calculations under section 9.01 each party shall credit or debit, as the case may be, the amount of contract standby charges paid directly to SEPA.

It is recognized by the parties hereto that future generating units may be installed by one party for the mutual benefit of all parties. A supplemental agreement may be required between the parties to reflect energy transactions from the generating unit and compensation required by the party installing the generating unit.

2.09 SPINNING RESERVE CAPACITY

The minimum amount of spinning reserve capacity operating on the pool system at any time shall be equal to the capacity of the largest generating unit in operation on the pool system at such time. Each party shall be responsible for operating its share of spinning reserve at such times as directed by the pool dispatcher, which share shall be that proportion of the minimum required spinning reserve in the pool system which represents the ratio of the input of that party's then operating generation to the total generation input to the pool system at that time. For the purposes of this sub-paragraph, standby capacity available to any party from SEPA shall be included in spinning reserve, and the amount of SEPA standby capacity available to each party shall be considered as that allocated to each party under the terms of section 2.08 hereof.

2.10 OPERATING COMMITTEE.

The Operating Committee shall consist of one representative and one alternate representative of each party. Each representative and alternate shall be designated in writing, delivered by each party to the other, and shall be a responsible person connected with the day-to-day operations of the designating party. The duties of the Operating Committee shall include the following:

(a) Maintain planning studies to determine the optimum manner of meeting the future capacity requirements of the pool system and recommend to the parties the additions or purchases to be made by each party, and the appropriate times therefor.

(b) Determine Certified Pool Capacity and Annual Pool System Peak.

(c) Prepare estimates of each party's annual system peak and each party's annual system capacity requirement, and submit to the parties recommendations for purchase and sale of equalization power to meet each party's system capacity requirement.

(d) Determine fuel costs, maintenance costs, unit start-up and loss factors, and determine such other data and information as may be needed for transactions under this Agreement.

(e) Determine mutually agreeable points of interconnection and facilities needed to implement these interconnections.

(f) Recommend and coordinate maintenance shut-downs for generation and major transmission facilities.

(g) Perform such other and further duties as may from time to time be mutually agreed upon by the parties.

The Operating Committee shall meet as often and at such times and places as may be mutually agreed upon. Each party shall pay its own committee expenses. Costs of joint planning studies or other costs shall be shared as mutually agreed by the parties.

2.11 MUTUAL ASSISTANCE

If, in the maintenance or utilization of their respective generation and transmission systems and related facilities for the purposes of this contract, it becomes necessary by reason of any emergency or extraordinary condition for any party to request the others to furnish personnel, materials, tools or equipment for the maintenance or modification of, or other work on such generation and transmission systems and related facilities in order to insure continuity of power and energy deliveries,

the party or parties requested shall cooperate and render such assistance as it or they may determine to be available. The party making such request, upon receipt of properly itemized bills, shall reimburse the assisting party or parties for all costs and expenses properly and reasonably incurred in rendering such assistance, including, without limitation, mutually agreed overhead charges. Such costs and expenses shall be computed on the basis of current charges or rates used by the assisting party in its own operations.

ARTICLE 3: TRANSMISSION SYSTEM

3.01 NOTICES

Each party shall promptly notify the other parties of any changes in the operation of its major transmission facilities which would affect the operation of the pool system. When reasonably possible, such notices shall be furnished in advance of such changes in sufficient time for the parties to properly adapt their operations to such changes.

3.02 TRANSMISSION OF CAPACITY AND ENERGY

Transmission facilities of each party's system, other than those facilities which directly serve purposes of interconnection, will first be used to supply the requirements of the party's own consumers and commitments. To the extent that transmission capacities are available in excess of the party's own requirements, it shall make available to the other parties such excess capacities. Each party shall have the right to make, or cause to be made, without cost or expense to the other parties, interconnections or extensions to its own Transmission System.

3.03 LOSSES

Each contracting party shall furnish its own capacity and energy losses. The Operating Committee shall determine capacity and energy losses, giving full consideration to displacement.

ARTICLE 4: EQUALIZATION POWER AND ENERGY

4.01 SCHEDULING

Equalization Power and associated energy shall be furnished and delivered in accordance with written schedules prepared by the Operating Committee from time to time, and shall not be scheduled in quantities which would create hazardous or grossly uneconomical operating conditions for the selling party's equipment.

4.02 SALE TO OTHER PARTY

The parties shall contract for the purchase and sale of Equalization Power in accordance with sub-article 2.07 hereof, which shall be scheduled through the Operating Committee.

4.03 COMPENSATION

Compensation for Equalization Power and associated energy shall be as provided in article 9 hereof.

ARTICLE 5: MAINTENANCE AND EMERGENCY POWER AND ENERGY

5.01 EMERGENCY POWER AND ENERGY

If a party requires power and energy during any emergency, the other parties shall, upon request, furnish such power and energy as the supplying party can supply without curtailment of service to its own

consumers, injury to its equipment, or conflict with its obligations to others not parties to this Agreement.

5.02 MAINTENANCE POWER AND ENERGY

If a party requires power and energy during any scheduled outage, the other parties shall, upon request, furnish such power and energy as the supplying party can supply without curtailment of service to its own consumers, injury to its equipment, or conflict with its obligations to others not parties to this Agreement.

The Operating Committee shall coordinate the schedules maintenance of generating facilities and major transmission facilities in order to maintain adequate pool capacity at all times.

5.03 COMPENSATION

Energy furnished during emergencies or scheduled outage shall be returned in kind by the receiving party according to a schedule to be mutually agreed upon by the parties involved. If the parties shall not make return in kind, or if such power and energy is furnished from parties not a party to this Agreement, such emergency or maintenance energy shall be paid for as provided in article 9 hereof.

ARTICLE 6: ECONOMY ENERGY

6.01 SCHEDULING

Tenders and acceptances of economy energy shall be made between the parties through their respective system dispatchers.

6.02. COMPENSATION

Compensation for economy energy shall be paid by the receiving party as provided in article 9 hereof.

ARTICLE 7: POWER AND ENERGY FLOW, METERING AND COMMUNICATIONS

7.01. RECOGNITION OF FLOW OF POWER AND ENERGY

It is recognized by the parties hereto that power and energy will be integrated with power and energy from generating facilities owned by others, and each party may have interconnection and exchange agreements with other power systems. Accordingly, the flow of power and energy between the systems of the parties hereto and the interconnected systems of others will in part be controlled by the physical and electrical characteristics of such systems, and power and energy purchased, sold or exchanged under this Agreement may flow through any or all of such interconnected systems. In order to account for the power and energy purchased, sold or exchanged under this Agreement the parties hereto shall, by mutual agreement, from time to time, determine methods and take appropriate action to establish accounting and operating procedures to be followed in calculating the amounts of power and energy delivered and received by each.

7.02 INADVERTENT FLOW AND BALANCING OFF

It is recognized that the flow of electric power and energy between the interconnected systems of the parties hereto will not be completely within the control of the parties, but will in part be

controlled by the electrical characteristics of such systems and the manner in which they are operated. It is further recognized that by reason of such characteristics and operations, the delivery of electric power and energy may vary from scheduled deliveries, and that power and energy may be exchanged inadvertently. The parties hereto agree to operate their generation, transmission and related facilities in such manner, consistent with their other power commitments, as to follow as closely as practicable the scheduled delivery and receipt of electric power and energy, but the inadvertent delivery of power and energy in excess of or less than the amounts scheduled shall not constitute a breach of this Agreement. Such inadvertent deviations from schedule shall be balanced off by the parties hereto as soon as practicable in the subsequent deliveries and receipts of power and energy and under load conditions reasonably comparable to those existing at the time said inadvertent deviations occurred. No charge shall be made by either party for inadvertent deliveries or for power and energy delivered to balance off the same.

7.03. REACTIVE POWER

Each party hereto shall normally provide all the reactive kilovolt amperes (kilovars) required for its own load.

7.04. METERING

Electric power and energy purchased and sold or exchanged under this Agreement shall be metered and accounted for in accordance with procedures and methods established from time to time by the Operating Committee.

7.05 COMMUNICATIONS FACILITIES

The parties shall install, operate and maintain, or cause to be installed, operated and maintained on their respective systems such equipment as may be required to afford a communication system between the pool dispatch office, the generating plants of the parties and such other points as may be required for operations under this Agreement.

ARTICLE 8: GENERAL PROVISIONS

8.01 CONSTRUCTION STANDARDS

The parties hereto shall construct, maintain and operate their respective systems and related facilities in accordance with standards and specifications at least equal to those provided by the National Electrical Safety Code of the United States Bureau of Standards, and as required by any regulatory authority having jurisdiction thereof.

8.02 FACILITIES FURNISHED

All parties shall furnish, install and operate, or cause to be furnished, installed and operated such facilities and equipment as may be reasonably necessary to interconnect their respective systems at the points of interconnection, including, without limitation, such metering equipment as may be required to measure the flow of power and energy at any point of interconnection and to assure reasonable protection to the system. The plan or plans for the installation of equipment for interconnection, metering and protection shall be submitted to the Operating Committee for prior approval, but such approval, if granted, shall not constitute a guaranty of the adequacy of such equipment.

8.03. RIGHT OF ACCESS

Each party hereto shall permit duly authorized representatives and employees of the other parties to enter upon its premises for the purpose of reading or checking meters, inspecting, testing, repairing, renewing or exchanging any or all of the equipment owned by the other party located on such premises, or for the purpose of performing any other work necessary in the performance of this Agreement. Each party shall be responsible for the safety of its own representatives and employees when on the premises of others pursuant to the right of access granted in this sub-article, and shall hold harmless and indemnify the party granting access from any loss or damage whatsoever by reason of any injury, including death, of such representatives and/or employees, unless the same shall be due to the negligence or willful misconduct of the party granting such access or its authorized representatives and employees.

8.04. RIGHT OF INSTALLATION

Each party hereto grants to the other permission to install, maintain and operate or cause to be installed, maintained and operated on its premises any and all terminal equipment and associated apparatus and devices necessary in the performance of this Agreement.

8.05. RIGHT OF REMOVAL

Any and all equipment, apparatus, devices or facilities placed or installed, or caused to be placed or installed, by any party hereto on or in the premises of another party shall be and remain the property of the party owning and installing such equipment, apparatus, devices or facilities, regardless of the mode or manner of annexation or attachment

to real property of the other, and upon the termination of this Agreement the owner thereof shall have the right, within a reasonable time, to enter upon the premises of the other and remove such equipment, apparatus, devices or facilities.

8.06 CONTINUITY OF DELIVERIES

Electric service under this Agreement shall meet accepted standards of reliability and adequacy. Electric power and energy delivered under this Agreement shall be furnished continuously and/or as scheduled, except for interruptions or curtailments in service caused by an uncontrollable force, by operation of devices installed for system protection, or by the necessary installation, maintenance, repair and/or replacement of equipment. Such interruptions or reductions in service, as hereinbefore set forth, shall not constitute a breach of this Agreement, and no party shall be liable to another party for damages resulting therefrom. Except in cases of emergencies, each party shall give the other parties reasonable advance notice of temporary interruptions or curtailments in service necessary for such installations, maintenance, repair and replacement of equipment, and shall schedule such interruptions or curtailments so as to cause the least inconvenience to the parties hereto.

8.07 UNCONTROLLABLE FORCE

No party hereto shall be considered to be default or breach with respect to any obligation under this Agreement if prevented from fulfilling such obligation by reason of an uncontrollable force. Any party unable to fulfill any obligation by reason of uncontrollable forces shall exercise due diligence to remove such disability as soon as reasonably possible.

8.08 REPORTS AND INFORMATION

The parties hereto shall furnish to each other, to the Operating Committee and to the Pool Dispatcher such reports and information concerning their operations as may be reasonably requested from time to time.

8.09. DISPATCHING OFFICE

To obtain the maximum benefits available under this Agreement, the parties hereto shall establish a dispatching office for the pool system. Said dispatching office shall be established as soon as technically and economically feasible. The said dispatching office shall, under the direction of the Operating Committee, schedule the generation and other capacity indicated as available to meet the combined load of the pool system, and shall perform such other and further duties as may from time to time be assiged in order to achieve the purposes of this Agreement. Each of the parties shall share equally cost of establishing and operating the dispatching office.

8.10 REMEDIES OF PARTIES

If any party breaches a material provision of this Agreement, the Agreement shall not be terminated, but the remedy for such breach shall be action for damages, injunction or other relief necessary to compel performance.

8.11 WAIVERS

Waiver at any time of rights with respect to a default or any other matter arising in connection with this Agreement shall not be deemed a waiver with respect to any other default or matter.

8.12 NOTICES

Any payment, written notice, demand or request, required or authorized under this Agreement shall be deemed properly given to or served upon the recipent when posted through regular United States mail, addressed as follows:

To Hoosier	:	Hoosier Energy Division P. O. Box 908 Bloomington, Indiana 47401
To Southern Illinois	:	Southern Illinois Power Cooperative P. O. Box 143 Marion, Illinois 62959
To Big Rivers	:	Big Rivers RECC P. O. Box 24 Henderson, Kentucky 42420
To Henderson	:	Municipal Power and Light P. O. Box 8 Henderson, Kentucky 42420

The designation of the persons to be notified, or the addresses of such persons, may be changed at any time upon written notice to the other parties.

8.13 SUCCESSORS AND ASSIGNS

This Agreement shall inure to the benefit of, and be binding upon the parties hereto, their respective successors and assigns.

8.14 RELATIONSHIP OF THE PARTIES

The terms of this Agreement shall not be construed as an Agreement for partnership, joint venture, association or other relationship, whereby any party shall be responsible for the obligations and/or liabilities of any other party hereto. No party to this Agreement shall

be liable for any act, omission or legal obligation of any other party hereto with respect to (a) the parties to this Agreement, (b) the agents, servants and/or employees of such party to this Agreement, or (c) any persons, corporations or other entities not a party to this Agreement. No party to this Agreement shall, by reason of the provisions hereof, be deemed a principal, agent, sub-contractor or employee of any other party hereto, nor shall any party to this agreement have the authority to bind any other party to this Agreement to any contract or other obligation, without specific written authority therefor.

ARTICLE 9: COMPENSATION

9.01 COMPENSATION FOR EQUALIZATION POWER AND ENERGY

The rate for equalization power and energy shall consist of a capacity charge and an energy charge as follows:

(a) Capacity charge of $10 per year for each kilowatt of contract demand, payable $0.83 1/3 per billing month.

(b) Energy charge per kilowatt-hour equal to the average fuel cost per net generated kilowatt-hour on the sellar's system for the preceding month plus 0.15 mills per kilowatt-hour. The average fuel cost shall be determined by dividing the total charges to Accounts 501, 518 and 547, as prescribed by the Federal Power Commission Uniform System of Accounts effective January 1, 1961, for fuel consumed during the months, by the total net generation in kilowatt-hours on the seller's system during the month.

9.02 COMPENSATION FOR EMERGENCY AND MAINTENANCE ENERGY

(a) Energy furnished during emergencies or scheduled outages as provided for in article 5 hereof shall be returned in kind by the receiving party upon a schedule to be mutually agreed upon by the parties involved. If the parties shall not agree upon such return in kind, such emergency or maintenance energy shall be charged to the account of the receiving party and credited to the account of the supplying party at the average fuel cost of net generation on the supplying party's system for the preceding month as defined in section 9.01 hereof plus 0.15 mills per kilowatt-hour.

(b) SEPA STANDBY

Where a scheduled or emergency outage necessitates the scheduling of SEPA Standby or standby power and energy from others not a party to this Agreement, any kilowatt per calendar day charges and standby energy charges resulting from such scheduling shall be paid for at the resulting cost by the party whose facility outage resulted in the charge.

9.03 COMPENSATION FOR ECONOMY ENERGY

Economy energy furnished shall be paid for by the receiving party at one-half (½) of the sum of the incremental operating expense of the plant or units from which energy is supplied and the decremental operating expense of the plant, units or source replaced, as adjusted to reflect transmission energy losses. Costs incurred in placing plant or units into operation shall be included where applicable. The Operating Committee shall annually determine in-bunker fuel costs, and costs of placing the respective plant or units in plant into operation.

9.04 COMPENSATION FOR PEAKING POWER

It is recognized that the purchases of peaking power from SEPA and other parties may incurr energy charges which tend to unfairly distort the purchaser's cost of power. When such purchases of peaking power represent Certified Pool Capacity, the energy associated with such peaking power shall be allocated to all parties to this Agreement on the ratio of that party's annual system peak to the sum of the annual system peaks of the parties, and the charges for that share of energy shall be debited to each party's account on the basis of the energy charges for such peaking power and a like amount credited to the account of the party purchasing such peaking power.

9.05. TAXES

If there shall be imposed after the affective date of this Agreement by federal, state or other governmental authority, any appropriate tax payable by any of the parties hereto upon any exchange under the terms of this Agreement shall be borne by the receiving party.

ARTICLE 10: ACCOUNTING, BILLING AND PAYMENT

10.01 RECORDS

Each party shall maintain, or cause to be maintained, an accurate record of the electric power and energy purchased, sold or exchanged under this Agreement, and on or before the 10th day of each month shall prepare and submit a statement covering the preceding month, setting forth in necessary detail the amount of power and energy purchased, sold and exchanged and the net balance in money.

10.02 PAYMENTS

Within 30 days after receipt of a billing statement, the party owing compensation to another party, as the case may be, shall pay or cause to be paid to the other party the net balance in money due as set forth in such statement.

ARTICLE 11: EFFECTIVE DATE, APPROVALS AND TERM

11.01. EFFECTIVE DATE AND APPROVALS

This Agreement shall be subject to any state or federal regulatory bodies having jurisdiction and shall become effective upon execution by the parties and approval by the Administrator of REA, and shall remain in effect until midnight October 31, 1987, and shall continue thereafter subject to the right of termination as hereinafter provided, except however, that the provisions section 2.08 and article 4 shall become operative on November 1, 1969.

This contract supercedes the agreements referred to in the stipulation and renders those null and void from and after the effective date of this contract.

11.02 TERMINATION

Any party to this Agreement may terminate its rights and obligations hereunder on or after October 31, 1987, by delivering written notice of its intention to so terminate to the other parties at least 5 years prior to the date of such termination, provided that no such termination shall become effective as long as an obligation exists upon the terminating party to any other party to this Agreement for the purchase or sale of equalization power under the terms of this Agreement or any supplement thereto. The terminating party shall not be required after

service of termination notice to enter into any such contract for purchase or sale of Equalization Power which would extend the otherwise effective date of termination.

ARTICLE 12: AMENDMENT INCLUSION OF OTHER PARTIES AND SEVERABILITY

12.01. This Agreement, or any portion thereof, may be amended from time to time, but only upon written memorandum of such amendment, accepted and executed by all of the parties to this Agreement, and approved by the Administrator of REA.

12.02. ADDITIONAL PARTIES

Upon mutual agreement of all of the parties hereto, additional persons, firms or corporations may become parties to this Agreement, provided, however, that any such additional party shall accept the terms and provisions of this Agreement and shall execute a copy thereof in acknowledgement of such acceptance, and thereafter shall be fully bound and obligated under the terms and provisions hereof and any amendments thereto.

12.03 SEVERABILITY

In the event that any part of this Agreement is declared illegal or no longer in force by reason of an order issued by a court or regulatory body of competent jurisdiction, all remaining portion of this Agreement which are not affected by such order shall continue in full force and effect.

IN WITNESS WHEREOF, the parties hereto, pursuant to the corporate authority of each of their respective Board of Directors and/or Commissioners, have executed this Agreement in several counterparts as of the day and year first above written.

ATTEST:

Secretary

The Hoosier Energy Division
INDIANA STATEWIDE RURAL ELECTRIC, INC.

By _____
~~President~~ Chairman

(corporate seal)

ATTEST:

Secretary

SOUTHERN ILLINOIS POWER COOPERATIVE

President

(corporate seal)

ATTEST:

Secretary

BIG RIVERS RURAL ELECTRIC COOPERATIVE CORPORATION

President

(corporate seal)

ATTEST:

Secretary

UTILITY COMMISSION,
CITY OF HENDERSON, KENTUCKY

Chairman

(corporate seal)

ATTEST: CITY OF HENDERSON, KENTUCKY

City Clerk Mayor

(city seal)

STATE OF Indiana

COUNTY OF Monroe . . . SCT.

I, Earl E Littell, a Notary Public in and for the state and county aforesaid, do hereby certify that on this day personally appeared before me Jerry Barnett as president and Walter Pritchard as secretary of Indiana Statewide Rural Electric, Inc., Hoosier Energy Division, who each signed and acknowledged the foregoing as said president and secretary to be their free and voluntary act and deed and the free and voluntary act and deed of said corporation.

Given under my hand and seal of office this 8 day of April, 19 66.

My commission expires March 27, 1970.

(seal) Earl E Littell
Notary Public, Monroe County, Indiana.

STATE OF ILLINOIS

COUNTY OF UNION . . . SCT.

I, CARL EDDLEMAN, a Notary Public in and for the state and county aforesaid, do hereby certify that on this day personally appeared before me K.R DOUGLAS as president and R.S.HOLT as secretary of Southern Illinois Power Cooperative, who signed and acknowledged the foregoing as said president

and secretary to be their free and voluntary act and deed and the free and voluntary act and deed of said corporation.

Given under my hand and seal of office this 28 TH. day of MARCH, 1968.

My commission expires 8-7-69.

Carol R. Eddleman
Notary Public Union County,

(seal)

STATE OF KENTUCKY

COUNTY OF HENDERSON . . . SCT.

I, Dorothy A. Fowler, a notary pbulic in and for the state and county aforesaid, do hereby certify that on this day personally appeared before me Robert Reid Jr as president and D. B. Nelson as secretary of Big Rivers Rural Electric Cooperative Corporation, who signed and acknowledged the foregoing as said president and secretary to be their free and voluntary act and deed and the free and voluntary act and deed of said corporation.

Given under my hand and seal of office this 15 day of March, 1968.

My commission expires Oct. 25, 1968.

Dorothy A. Fowler
Notary Public, Henderson County, Kentucky

(seal)

STATE OF KENTUCKY

COUNTY OF HENDERSON . . . SCT.

I, _____, a notary public in and for the state and county aforesaid, do hereby certify that on this day appeared before me _____ and _____, personally known to me to be the chairman and secretary of the Utility Commission of the City of Henderson, Kentucky who signed and acknowledged the foregoing instrument to be their own free and authorized act and deed.

Given under my hand and seal of office this _____ day of _____, 19_____.

My commission expires Notary Public, Henderson County, Kentucky My Commission Expires February 16, 1972.

(seal)

_____
Notary Public, Henderson County, Kentucky

STATE OF KENTUCKY

COUNTY OF HENDERSON . . . SCT.

I, _____, a notary public in and for the state and county aforesaid, do hereby certify that on this day appeared before me _____ and _____, personally known to me to be the Mayor and City Clerk of the City of Henderson, Kentucky who signed and acknowledged the foregoing as said mayor and city clerk to be their free and voluntary act and deed and the free and voluntary act and deed of said City of Henderson.

Given under my hand and seal of office this 4 day of _____, 19__.

My commission expires _____.

(seal)

_____
Notary Public, Henderson County, Kentucky

EXHIBIT A

INTERCONNECTION AGREEMENT - APRIL 1, 1968

Points of interconnection shall be:

1. Troy Interconnection:

At the state boundary between Indiana and Kentucky near Troy, Indiana where Hoosier's 161 KV lines extending from the Taswell transmission substation connects with Big Rivers' 161 KV lines extending from the Coleman Power Plant near Hawesville, Kentucky.

2. Bay City Interconnection:

At the state boundary between Kentucky and Illinois near Bay City, Illinois where Big Rivers' 161 KV line extending from the Barkley Dam substation connects with Southern Illinois' 161 KV line extending from the Renshaw transmission substation.

3. Shawneetown Interconnection:

At the state boundary between Kentucky and Illinois near Shawneetown, Illinois where Southern Illinois' 69 KV line extending from the New Gallatin switching station connects with Big Rivers' 69 KV line extending from the Morganfield switching station.

4. Henderson East:

At the city limits of Henderson, Kentucky where Henderson's 69 KV line extending from the Fifth and Elm substation connects with Big Rivers' 69 KV line extending from the Zion substation.

5. Henderson South:

At the city limits of Henderson, Kentucky where Henderson's 69 KV line extending from the Fifth and Elm substations connects with Big Rivers' 69 KV line extending from Henderson-Union's Henderson substation.

Supplemental Agreement No. 2
Contract No. 14-05-0001-377
TV-33450A, S#2
(WAS 14-05-0001-305, S#5
TV-23766A, S#5
PRIOR TO THIS

United States Department of the Interior

SOUTHEASTERN POWER ADMINISTRATION
ELBERTON, GEORGIA 30635

CONFORMED COPY

IN REPLY REFER TO:

March 1, 1967

THIS CONTRACT WAS FINALLY ASSIGNED:
14-05-0001-502, S#1
TV-37814A, S#1
AS OF 7-1-73, WHICH NO. REMAINS EFFECTIVE TODAY
9-18-80
MRK

Mr. G. O. Wessenauer
Manager of Power
Tennessee Valley Authority
Chattanooga, Tennessee 37401

Dear Mr. Wessenauer:

Big Rivers Rural Electric Cooperative Corporation (herein called "Big Rivers") is ready to proceed with the construction of the 161-kv transmission line from a point on its system near Hardinsburg, Kentucky, to a point near Paradise, Kentucky. Big Rivers has agreed to bear all costs associated with the establishment, maintenance, and operation of an additional point of delivery at the latter location for the delivery by SEPA to Big Rivers of power retained by SEPA from generation on the Cumberland River and to be delivered for SEPA's account at that point of delivery. Accordingly, pursuant to section 2.4 of Article II of our contract (herein called "1963 Contract") dated March 1, 1963, 14-05-0001-305 (TV-23766A), I hereby request the establishment of an additional point of delivery near Paradise, Kentucky, at the point on TVA's system which our representatives have previously selected in accordance with the following arrangements:

1. TVA will make an estimate of the total cost, including applicable overheads, for designing, engineering, procuring, and installing the facilities for the terminus of Big Rivers' Hardinsburg-Paradise 161-kv transmission line near Paradise in accordance with plans and specifications prepared and approved by TVA and satisfactory to SEPA and to Big Rivers. Such facilities shall include without limitation a circuit breaker, telemetering and communication equipment, metering equipment, and other accessory equipment to be located in the switchyard near TVA's Paradise plant; and four double-circuit steel towers complete with one circuit consisting of conductors, insulators, associated hardware, and overhead ground wires. In order to conserve rights-of-way, said steel towers will be located on rights-of-way owned by the United States and in TVA's custody. The aforesaid estimate shall include the total cost as shown on TVA's books of said rights-of-way and of securing any additional rights-of-way required.

2. It is recognized that the connection with Big Rivers' line near Paradise is for the use and benefit of SEPA and its use will require TVA to make, at locations on its system other than at Paradise, modifications in or additions to its telemetering, communications, relaying, and load control facilities for the coordinated operation of the terminal facilities on said line with TVA's system. TVA shall give SEPA an estimate of the total cost, including applicable overheads, of designing, engineering, and making the modifications or additions which TVA deems necessary for such purpose.

3. Upon receipt of funds from Big Rivers in an amount equal to the sum of the aforesaid estimates provided for in sections 1 and 2 above, TVA shall proceed diligently to procure and install the facilities described in sections 1 and 2 above and shall be obligated to operate, maintain, and repair them thereafter, subject, however, to the provisions of sections 5 and 7 hereof.

4. Upon completion of the installation of the facilities described in sections 1 and 2, respectively, TVA shall furnish SEPA and Big Rivers itemized statements of the total actual costs, including applicable overheads, incurred by TVA in making the respective aforesaid estimates provided for in sections 1 and 2 and in designing, engineering, procuring, and installing the respective aforesaid facilities described therein. If the total actual costs, respectively, exceed the amounts advanced therefor under section 3 above, SEPA shall arrange for Big Rivers to pay to TVA the amounts of the respective excesses. If said total actual costs, respectively, are less than the amounts advanced therefor, TVA shall refund to Big Rivers the respective differences.

5. SEPA shall arrange for Big Rivers to advance to TVA annually funds at least equal to TVA's anticipated costs, including applicable overheads, of operating, maintaining, and repairing the facilities referred to in sections 1 and 2 above in accordance with this section 5. On or before June 1 of the calendar year 1968 and of each subsequent calendar year during the term of this agreement, TVA will submit to SEPA and Big Rivers a statement of said anticipated costs for the next fiscal year beginning July 1. Big Rivers shall advance to TVA on or before June 15 of each year beginning with calendar year 1968 funds equal to such anticipated costs shown on such statement for the next ensuing fiscal year. Upon expiration of this agreement, any funds advanced under this section 5 that have not been used by TVA for payment of such costs shall be promptly returned to Big Rivers.

6. Any modifications, additions, or replacements in, to, or of the respective facilities described in sections 1 and 2 hereof required in TVA's judgment shall be made by TVA at Big Rivers' expense.

7. At any time during the term of this agreement, TVA shall have the right to install for its own use a circuit on the side of the aforementioned double-circuit towers not occupied by Big Rivers' Hardinsburg-Paradise 161-kv line. If TVA installs such circuit, TVA shall promptly repay to Big Rivers one-half of the aforesaid total costs of the rights-of-way and of the installed costs of the towers and ground wires. From and after the date on which TVA completes the installation of such circuit for its own use, TVA shall bear one-half of the cost of repairing, maintaining, replacing, and modifying said towers and ground wires and of maintaining rights-of-way.

8. SEPA shall make all arrangements with Big Rivers necessary or desirable for performance of this agreement in accordance with its terms. Nothing herein shall prevent the parties from making mutually satisfactory arrangements for Big Rivers to procure and deliver to TVA any part or parts of the facilities described in sections 1 and 2 hereof with appropriate adjustments in the amount to be advanced to TVA under section 3 hereof.

9. This agreement shall become effective as of the date first above written and shall continue in effect for the term of the 1963 Contract, subject, however, to the following obligations which shall survive the expiration of the term of this agreement. SEPA shall arrange for Big Rivers, as soon as practicable after the end of said term, to advance to TVA its estimated costs, including applicable overheads, of removing the facilities installed under section 3 hereof, and TVA shall remove said facilities and deliver them to Big Rivers at Paradise, Kentucky, or any other mutually satisfactory point promptly after receipt of such advance; provided, however, that TVA may elect to keep the four double-circuit steel towers and aforesaid overhead ground wires in place, and in the event it so elects it shall promptly reimburse Big Rivers for the depreciated value as determined by TVA of any remaining investment Big Rivers may have in said towers and ground wires and in the rights-of-way therefor. If TVA's actual costs, including applicable overheads, of such removal and delivery exceed the amount advanced by Big Rivers therefor, SEPA shall arrange for Big Rivers to pay such excess to TVA. If said actual costs are less than the amount advanced by Big Rivers, TVA shall refund to Big Rivers the difference.

If this letter satisfactorily states the terms of our understanding, please indicate TVA's acceptance hereof by signing and returning four copies hereof to me.

Sincerely yours,

/s/ Chas. W. Leavy

Chas. W. Leavy
Administrator

Accepted and agreed to as of
the date of this letter.

TENNESSEE VALLEY AUTHORITY

By /s/ L. J. Van Mol
L. J. Van Mol
General Manager

(SEAL)

CAR
LAW

APPROVED BY TVA
BOARD OF DIRECTORS

May 11, 1967

M. E.
ASSISTANT SECRETARY

Contract # 879

TENNESSEE VALLEY AUTHORITY
CHATTANOOGA, TENNESSEE 37401
315 401 Building
(615) 751-6781

FILE COPY

January 30, 1985

Mr. Scott Reed
Vice General Manager of
Engineering & Transmission
Big Rivers Electric Corporation
201 3rd Street
Henderson, Kentucky 42420

Dear Mr. Reed:

Enclosed for your use are four fully executed copies of our letter agreement TV-65748A, dated January 16, 1985, covering the establishment of additional delivery points between the systems of TVA and Big Rivers.

We appreciate your cooperation in handling this matter.

Very truly yours,

TENNESSEE VALLEY AUTHORITY

S. D. Reynolds/cvb

S. D. Reynolds, Chief
Direct Service Branch

Enclosures

TENNESSEE VALLEY AUTHORITY
KNOXVILLE, TENNESSEE 37902
400 West Summit Hill Drive

JAN 16 1985

Mr. William H. Thorpe
General Manager
Big Rivers Electric Corporation
P.O. Box 24
Henderson, Kentucky 42420

Dear Mr. Thorpe:

This will confirm the arrangements agreed upon between representatives of Big Rivers Electric Corporation (hereinafter called "Big Rivers") and the Tennessee Valley Authority (hereinafter called "TVA") for the establishment, operation, and maintenance of a delivery point near TVA's Shawnee Steam Plant (hereinafter called "Shawnee Delivery Point") and arrangements for an optional second delivery point at TVA's Marshall Substation (hereinafter called the "Marshall Delivery Point") and for TVA to provide emergency transmission service for Big Rivers from other points of connection between the systems of TVA and Big Rivers through TVA's transmission facilities to the Shawnee Delivery Point and, in the event it is established, to the Marshall Delivery Point.

In consideration of the mutual agreements set forth herein and subject to the provisions of the Tennessee Valley Authority Act of 1933, as amended, it is understood and agreed that:

1. Establishment of the Shawnee Delivery Point.

   (a) Big Rivers shall, at its expense and in accordance with plans and specifications satisfactory to TVA, construct, own, operate, and maintain (1) a 161-kV tapline from its McCracken County Substation to a point mutually agreed upon in TVA's Shawnee-C33 161-kV "L" Line (hereinafter called "L Line") near TVA's Shawnee Steam Plant and (2) associated terminal facilities in its McCracken County Substation. Said terminal facilities shall include (1) an oil circuit breaker and related structure, busses, and switches, (2) relaying facilities which will afford protection to Big Rivers' facilities and will coordinate with the operation of TVA's transmission facilities, (3) metering facilities to measure power flows between the systems of Big Rivers and TVA at the Shawnee Delivery Point, and (4) telemetering facilities necessary for the operation of Big Rivers' and TVA's systems, respectively (the plans for such telemetering facilities being approved in advance by TVA).

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Mr. William H. Thorpe

JAN 16 1985

(b) TVA, at Big Rivers' expense, shall provide, own, operate, and maintain (1) a tap structure in the L Line for the connection of Big Rivers' tapline to the L Line, and (2) telemetering, relaying, communication, and control facilities on its system as it deems necessary for the operation of the Shawnee Delivery Point.

(c) The facilities provided for under this section 1 shall be completed and ready for operation as soon as practicable following the advancement of funds by Big Rivers to TVA as provided in section 3 below.

2. Establishment of the Marshall Delivery Point.

(a) If at any time after one year following the effective date of this agreement, TVA determines that an additional delivery point to Big Rivers at TVA's Marshall Substation would enhance reliability on the TVA system during the transactions provided for hereunder, TVA shall upon notification to Big Rivers have the right to have the Marshall Delivery Point established, operated, and maintained pursuant to the terms and conditions hereinafter set forth in this agreement.

(b) Big Rivers, at its expense and in accordance with plans and specifications satisfactory to TVA, shall construct, own, operate, and maintain 161-kV circuits extending from a nearby point in its Livingston County-McCracken County 161-kV Line (hereinafter called "Livingston-McCracken Line") to TVA's Marshall Substation, as necessary to loop its Livingston-McCracken Line into TVA's Marshall Substation.

(c) TVA, at Big Rivers' expense, shall provide, own, operate, and maintain in its Marshall Substation terminal facilities for Big Rivers' 161-kV circuits provided for in subsection (b) above. Said terminal facilities shall include (1) oil circuit breakers and related structures, busses, and switches, (2) relaying facilities which will afford protection to Big Rivers' facilities and coordinate with the operation of TVA's facilities, (3) metering facilities to measure the power flows between the systems of Big Rivers and TVA at the Marshall Delivery Point, and (4) telemetering facilities necessary for the operation of Big Rivers' and TVA's systems, respectively (the plans for such telemetering facilities being approved in advance by Big Rivers).

(d) TVA shall also provide, own, operate, and maintain telemetering, relaying, communication, and control facilities at other locations on its system as it deems necessary for the operation of the Marshall Delivery Point.

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(e) The facilities provided for under this section 2 shall be completed and ready for operation as soon as practicable following the date on which TVA notifies Big Rivers under subsection (a) above and Big Rivers advances funds to TVA for its portion of said facilities as provided in section 3 below.

3. Advanced Funds for Installation of Facilities.

(a) As soon as practicable following the effective date of this agreement, TVA shall give Big Rivers an estimate of the total cost, including applicable overheads, for designing, engineering, procuring, and installing the tap structure and other facilities pursuant to subsection (b) of section 1 above. Promptly after receipt of said estimate, Big Rivers shall advance to TVA funds in the amount of said estimate and TVA shall thereupon proceed diligently to procure and install said facilities. Upon completion thereof, TVA shall furnish to Big Rivers an itemized statement of the actual costs, including applicable overheads, incurred by TVA under subsection (b) of section 1 above. If the actual costs exceed the amount advanced therefor, Big Rivers shall pay to TVA the amount of the excess. If the actual costs are less than the amount advanced therefor, TVA shall refund to Big Rivers the difference.

(b) Upon exercising its right under subsection (a) of section 2 above to have the Marshall Delivery Point established, TVA shall give Big Rivers an estimate of the total cost, including applicable overheads, for designing, engineering, procuring, and installing the terminal facilities in TVA's Marshall Substation, and any additional facilities to be installed at other locations pursuant to subsections (c) and (d) of section 2 above. Promptly after receipt of said estimate, Big Rivers shall advance to TVA funds in the amount of said estimate and TVA shall thereupon proceed diligently to procure and install said facilities. Upon completion thereof, TVA shall furnish to Big Rivers an itemized statement of the actual costs, including applicable overheads, incurred by TVA under subsections (c) and (d) of section 2 above. If the actual costs exceed the amount advanced therefor, Big Rivers shall pay to TVA the amount of the excess. If the actual costs are less than the amount advanced therefor, TVA shall refund to Big Rivers the difference.

4. Ownership of Facilities. The facilities installed by TVA hereunder shall, subject to section 14 below, be and remain the property of TVA.

5. Advanced Funds for Operation, Maintenance, and Repairs. TVA, at Big Rivers' expense, shall operate, maintain, and repair the facilities provided by TVA pursuant to sections 1 and 2 above. Big Rivers shall advance to TVA annually funds at least equal to TVA's anticipated

Mr. William H. Thorpe

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costs, including applicable overheads of operating, maintaining, and repairing said facilities in accordance with this section 5. On or before June 1 of each calendar year during the term of this agreement, TVA will submit to Big Rivers a statement of said anticipated costs for the ensuing 12-month period, beginning July 1 of each such year. (The initial statement to be submitted by TVA to Big Rivers will include actual and anticipated costs for the period beginning with the effective date hereof and extending to the beginning of the initial 12-month period covered in said statement.) Each said statement shall, as appropriate, be decreased to reflect any unused funds from the previous year or be increased to reflect the amount by which the previous year's actual costs exceeded the anticipated costs therefor. Big Rivers shall advance to TVA on or before June 15 of each such year funds equal to such anticipated costs shown on such statement, with such increases or decreases as described in the preceeding sentence, for the ensuing 12-month period, beginning July 1 of each such year. Upon expiration or termination of this agreement, any funds advanced under this section 5 that have not been used or obligated by TVA for payment of such costs shall be promptly returned to Big Rivers.

6. Modifications, Additions, or Replacements. TVA, at Big Rivers' expense, shall make such modifications, additions, or replacements in, to, or of the respective facilities provided by TVA pursuant to sections 1 and 2 hereof as TVA in its judgment considers to be appropriate. Such modifications, additions, or replacements shall include any metering and telemetering facilities as considered useful by TVA to accommodate such modes of operation or other practices that may be followed by TVA from time to time.

7. Emergency Transmission Service. It is recognized that in the event supply of power over Big Rivers' Livingston-McCracken Line is interrupted or curtailed, Big Rivers has no alternative transmission route to its McCracken County Substation. The parties therefore agree that:

   (a) In the event of such interruption or curtailment of transmission over said line due to a forced outage or necessary scheduled maintenance, TVA agrees to provide transmission service for the requirements of the McCracken County Substation. Big Rivers will inform TVA as promptly as feasible of the occurrence of any such interruption or curtailment and will advise TVA as to its cause and likely duration. Big Rivers shall use due diligence to restore normal service over the Livingston-McCracken Line at the earliest practicable time and will notify TVA immediately when normal service has been restored.

   (b) Power for transmission hereunder shall be accepted by TVA at the existing points of connection between TVA and Big Rivers at Barkley Hydro Plant and Paradise Steam Plant and, upon completion

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of the Marshall Delivery Point, at the Marshall terminus of the Livingston-Marshall segment of the Livingston-McCracken Line. Such power (less such amounts as provided for in section 9 below) shall be delivered by TVA to Big Rivers at the Shawnee Delivery Point and, upon completion of the Marshall Delivery Point, at the Marshall terminus of the Marshall-McCracken segment of the Livingston-McCracken Line.

(c) Except for the interruption or curtailment of transmission service as provided for in section 8 below, TVA shall transmit through its transmission system and deliver such transmitted power and energy on a simultaneous basis with, and only in such amounts as, the power and energy accepted by TVA for such transmission and delivery (less such amounts as provided for in section 9). Big Rivers shall notify TVA or cause TVA to be notified promptly of any interruption or curtailment in the availability of power and energy for acceptance by TVA hereunder. TVA shall not be obligated to supply power and energy from its own sources or from its purchases from other neighboring systems during interruptions or curtailments in the delivery to TVA of power and energy for transmission service hereunder, and nothing in this agreement shall have the effect of making, nor shall anything in this agreement be construed to require TVA to take any action which would make TVA, directly or indirectly, a source of power supply to Big Rivers.

(d) In the event Big Rivers provides or arranges for the provision of an additional transmission route to the McCracken County Substation which TVA, in its sole judgment, deems capable of supplying the needs of said substation, TVA shall have the right at any time following the completion of such additional transmission route to terminate this agreement upon 30 days' notice.

8. Interference with Availability of Transmission Service. TVA may curtail or interrupt transmission service hereunder as, if, and when, in TVA's judgment, continuation of such transmission service could jeopardize service to TVA's customers or reduce the reliability of TVA's system, either with respect to TVA's customers or with respect to TVA's interconnections with neighboring electric systems. TVA shall not be considered to be in default with respect to any obligation hereunder in the event of any such curtailment or interruption of transmission service or if TVA is prevented from fulfilling such obligation because of force majeure or otherwise. The term "force majeure" shall be deemed, for the purposes of this agreement, to be a cause reasonably beyond the control of the party affected, such as, but without limitation to, injunction, strike of the party's employees, war, invasion, fire, accident, floods, backwater caused by floods, acts

of God, or inability to obtain or ship essential services, materials, or equipment because of the effect of similar causes on the party's suppliers or carriers.

TVA shall notify Big Rivers promptly of any such curtailment or interruption of transmission service under this section 8.

9. Transmission Losses. It is recognized that transmission losses will occur in periods during which TVA provides transmission service pursuant to section 7 above, and the parties agree that power adequate to compensate TVA for all such losses shall be supplied by Big Rivers. Accordingly, beginning with the occurrence of any interruption or curtailment of transmission over Big Rivers' Livingston-McCracken Line, and continuing until normal service is restored, Big Rivers shall deliver to TVA on a continuous basis, without charge and in addition to all other scheduled and unscheduled deliveries to TVA, 2,000 kW of power as compensation for transmission losses. In the event TVA determines that 2,000 kW is insufficient to cover the transmission losses being incurred, TVA shall notify Big Rivers of the additional amount of power needed to cover such losses, and Big Rivers shall promptly increase its deliveries under this section 9 by such additional amount.

10. Compensation to TVA for Provision of Transmission Service. As consideration for provision of transmission service by TVA, Big Rivers hereby grants to TVA the right to use the marginal capacity in the tapline provided for in section 1 above, the Livingston-McCracken Line, the Livingston-Barkley Hydro 161-kV Line, and all associated terminal facilities to transmit TVA power between the TVA facilities at Shawnee Steam Plant and the TVA facilities at Barkley Hydro Plant, and, upon the completion of the Marshall Delivery Point, among the TVA facilities at the Marshall Substation, the TVA facilities at Barkley Hydro Plant, and the TVA facilities at Shawnee Steam Plant. Under no circumstances shall Big Rivers divert or utilize in any way any power being transmitted by TVA under this section 10. In the event that TVA's usage of such marginal capacity could jeopardize service to Big Rivers' customers or reduce the reliability of Big Rivers' system, Big Rivers may curtail or interrupt TVA's usage of such marginal capacity, and Big Rivers shall not be considered to be in default hereunder on account of such interruption or curtailment.

11. Accessory Facilities Provided by Big Rivers and Operation of Big Rivers' System. Big Rivers will make, at locations on its system, such modifications in or additions to its telemetering, communications, and control facilities as are necessary or appropriate for the coordinated operation of Big Rivers' and TVA's systems under this agreement. Such modifications in or additions to telemetering, communications, and control facilities and the operation of Big Rivers' power resources shall conform to the North American Electric Reliability Council (NERC) operating guide for automatic generation control practices for acceptable control performance.

Mr. William H. Thorpe JAN 16 1985

12. Liability. Big Rivers and TVA shall each be responsible for providing and maintaining such protective facilities on their respective systems as may be required to safeguard persons, property, and system operations. There are no warranties, express or implied, by either party to the other with respect to the adequacy or effectiveness of any equipment installed under this agreement.

Big Rivers hereby releases and shall indemnify and save harmless TVA and the United States of America from any and all claims, demands, or causes of action for loss of life or for loss, injury, or damage to persons or property arising out of or in any way connected with the construction, operation, or maintenance of telemetering, relaying, or other equipment installed by TVA under this agreement, unless such loss of life or loss, injury, or damage to persons or property is caused by the sole negligence of TVA or the United States of America, their agents, servants, or employees.

TVA hereby releases and shall indemnify and save harmless Big Rivers from any and all claims, demands, or causes of action for loss of life or for loss, injury, or damage to persons or property arising out of or in any way connected with the construction, operation, or maintenance of telemetering, relaying, or other equipment installed by Big Rivers under this agreement, unless such loss of life or loss, injury, or damage to persons or property is caused by the sole negligence of Big Rivers, its agents, servants, or employees.

13. Restriction of Benefits. No member of or delegate to Congress or Resident Commissioner, or any officer, employee, special Government employee, or agent of TVA shall be admitted to any share or part of this agreement or to any benefit that may arise therefrom unless the agreement be made with a corporation for its general benefit, nor shall Big Rivers offer or give, directly or indirectly, to any officer, employee, special Government employee, or agent of TVA any gift, gratuity, favor, entertainment, loan, or any other thing of monetary value, except as provided in 18 C.F.R. § 1300.735-12 or -34. Breach of this provision shall constitute a material breach of this agreement.

14. Term. This agreement shall become effective as of the date first above written and shall, subject to the provisions of sections 7 and 8 above, continue in effect for an initial term of 10 years and from year to year thereafter until terminated by either party upon five years' advance written notice; subject, however, to the following obligations which shall survive the expiration of the term (or the termination) of this agreement: as soon as practicable after the end of said term (or such termination), TVA shall estimate the costs, including applicable overheads, of removing the facilities installed under sections 1 and 2 hereof and shall furnish such estimate to Big Rivers, which shall promptly advance this amount to TVA. TVA shall thereupon promptly remove said facilities and deliver them to Big Rivers at Marshall

JAN 16 1985

Mr. William H. Thorpe

Substation, or any other mutually satisfactory point. If TVA's actual costs, including applicable overheads of such removal and delivery exceed the amount advanced by Big Rivers therefor, Big Rivers shall pay such excess to TVA. If said actual costs are less than the amount advanced by Big Rivers, TVA shall refund to Big Rivers the difference.

15. Regulatory Approval. This agreement is made subject to receipt by Big Rivers of any requisite governmental and regulatory approvals, including that of the Administrator of the Rural Electrification Administration.

If this letter satisfactorily states the understanding between us, please execute and return six copies to me. Upon completion by TVA four fully executed copies will be returned to you.

Very truly yours,

TENNESSEE VALLEY AUTHORITY

W. F. Willis
General Manager

JMc
OGC

Approved by TVA Board of Directors
JAN 16 1985
HSD
ASSISTANT SECRETARY

Accepted and agreed to as of the date first above written.

BIG RIVERS ELECTRIC CORPORATION

By Morton Henshaw
Title:

R113084

Copy: Schmitz
Dolezal
Reed

TENNESSEE VALLEY AUTHORITY

CHATTANOOGA, TENNESSEE 37401

6N 13D Signal Place

January 15, 1988

Mr. William H. Thorpe
General Manager
Big Rivers Electric Corporation
P.O. Box 24
Henderson, Kentucky 42420

Dear Mr. Thorpe:

This letter is to confirm that TVA, in accordance with the provisions of letter Agreement TV-65748A, dated January 16, 1985, between Big Rivers and TVA, has determined that an additional delivery point to Big Rivers at TVA's Marshall Substation would enhance reliability on the TVA system during the transactions provided thereunder. Accordingly, this is to provide written notification to Big Rivers that TVA is hereby exercising its right under subsection (a) of section 2 of said letter agreement to have the Marshall delivery point established, operated, and maintained in accordance with the provisions of said letter agreement, with an in-service date of June 1, 1990. TVA will, as soon as practicable, provide an estimate of the total cost, including applicable overheads, for designing, engineering, procuring, and installing the terminal facilities in TVA's Marshall Substation, and any additional facilities to be installed at other locations, in accordance with said letter agreement.

Very truly yours,

TENNESSEE VALLEY AUTHORITY

Richard B. Davis
Director of Energy Use
and Distributor Relations

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES CASE NO. 2013-00199

Response to the Kentucky Industrial Utility Customers, Inc.'s Second Request for Information dated September 16, 2013

September 30, 2013

Item 50) ***Refer to the Company's response to AG 1-53 page 26 of 56.***

a. ***Please provide a copy of all materials relied on by Mr. Haner for his comments to the BOD, including, but not limited to, all analyses and indicative bids for the cost of insurance coverage for 2014.***

b. ***Please provide the most recent analyses and indicative bids for the cost of insurance coverage for 2014.***

c. ***Please provide a schedule showing the company's actual insurance expense for each type of coverage in 2010, 2011, 2012, 2013, and the test year.***

d. ***Please indicate whether the Company expects its insurance expense to decline or increase in 2014 when it markets its coverages.***

Response)

a. There are no materials with regard to comments made to the BOD about property and casualty insurance procurement for 2014. Big Rivers' property and casualty insurance procurement procedures call for competitive bidding among multiple agents every three years. When replacing coverage in intervening years, the agent selected in the three-year competitive bidding process solicits quotes from multiple insurers in an effort to obtain coverage at

the lowest possible cost. The three-year bidding process was scheduled to take place in 2013; however, it was deferred due to the uncertainty surrounding the idling of one or more of Big Rivers' generation facilities.

b. To date, there are no analyses or indicative bids with regard to insurance procurement for 2014 as insurance companies do not provide quotes prior to 30 days before start of coverage.

c. Please see attached schedule.

d. The expense for property and casualty insurance for 2014 is expected to increase due to current market conditions.

Witness) Thomas W. Davis

Big Rivers El[illegible]ic Corporation
Case No. [illegible]013-00199
Attachment for Response to KIUC 2-50(c)
Insurance Expense

Coverage Type	2010	2011	2012	YTD through 8/31/13	Test Year Feb-14 to Jan15
Property	2,940,794	2,271,160	2,956,372	2,257,503	3,514,587
Automobile	112,682	100,217	100,544	54,038	108,812
General Liability	46,435	62,110	61,197	40,114	66,431
D&O	58,177	58,333	58,333	40,485	63,417
Accident	3,265	3,763	3,763	2,718	4,162
Marine	99,901	69,423	64,448	38,514	76,325
Umbrella	61,623	66,880	70,379	51,214	75,915
Crime	5,018	5,031	5,031	3,355	5,446
Directors Group Life	3,252	2,985	2,844	1,799	3,163
Subtotal	**3,331,147**	**2,639,902**	**3,322,911**	**2,489,740**	**3,918,258**
Less Station Two portion	(391,986)	(309,843)	(397,480)	(301,955)	(470,405)
Total	**2,939,161**	**2,330,059**	**2,925,431**	**2,187,785**	**3,447,853**

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2013-00199

Response to the Kentucky Industrial Utility Customers, Inc.'s
Second Request for Information
dated September 16, 2013

September 30, 2013

Item 51) ***Refer to the Company's response to AG 1-158 page 10 of 13. Please provide the underlying support, including all assumptions, data, computations, and electronic workpapers with formulas intact, to compute the price ($/mWh) shown on this page.***

Response) The information on page 10 of 13 in response to AG 1-158 is an output from the forecast "Financial Forecast (2014-2027) 5-16-2013.xlsx" provided in response to PSC 2-14. The reference files that are linked to create this financial model run were either provided in PSC 1-57 or KIUC 2-20. The replacement load pricing used was the off-system market plus 25%.

Witness) Christopher A. Warren

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2013-00199

Response to the Kentucky Industrial Utility Customers, Inc.'s
Second Request for Information
dated September 16, 2013

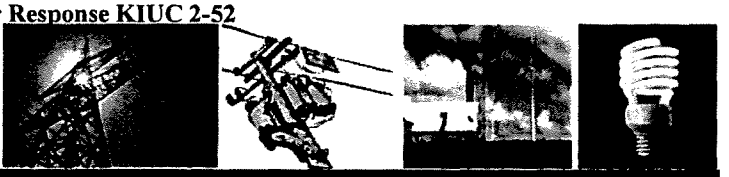
September 30, 2013

Item 52) ***Refer to the Debt tab on the Company's Financial Forecast (2014-2017) 5-16-2013.xlsx. Provide the source of the ECP financing and the source of the interest rate assumption.***

Response) The planned source of permanent financing for Big Rivers' 2012 Environmental Compliance Plan ("ECP") is a Rural Utilities Service ("RUS") Guaranteed Federal Financing Bank ("FFB") Loan with a 30-year term. In May 2013, Big Rivers submitted an RUS Loan Application Package to the RUS requesting an RUS Guaranteed FFB Loan with a 30-year term in the amount of $58.44 million. Big Rivers plans to obtain a $60 million senior secured three-year credit facility through National Rural Utilities Cooperative Finance Corporation ("CFC") for interim financing of its 2012 ECP until permanent financing through the RUS can be secured. The interest rate assumption of 3.0% was based on current RUS FFB loan rates, rounded to the nearest whole percentage point, available at the time the forecast was developed. Please see attachment for a copy of the RUS Electric Quarterly Newsletter from March 2013, which includes approximate FFB Quarterly Rates for a 30-year term loan.

Witness) Christopher A. Warren

USDA United States Department of Agriculture
Rural Development



RUS ELECTRIC QUARTERLY NEWSLETTER

Helping improve the economy and life in rural America

Volume II Issue II

Assistant Administrator's Corner

It was great seeing many of you at NRECA's annual convention in February. I enjoyed the opportunity to meet with you and discuss the issues you face, potential funding opportunities, and update you on Electric Program initiatives. Acting Administrator John Padalino was deeply honored to be the key-note speaker and enjoyed the opportunity to sit down with you and discuss the issues facing the cooperative community.

Spring is on its way, as is construction season. Our interest rates remain at historical lows, and we would be happy to discuss financing opportunities. Please feel free to reach out to myself or my staff. We always look forward to your phone call or email.

- Nivin Elgohary

PROGRAM FUNDING

RUS continues to operate under a continuing resolution (CR) which runs through March 27, 2013. The table below represents the Electric Program's partial loan budget allocation under the CR. Congress is currently holding discussions on extending the CR through fiscal year 2013.

FISCAL YEAR 2012 LOANS AND GUARANTEES						
	#	FFB	#	Hardship	#	Guaranteed Underwriter
Program Level		$3,170,050,000		$48,770,000		$424,286,000
Approved	26	$558,009,000	0	$0	0	$0

We encourage all who plan to submit a loan application this year to work with your field representative to finalize the submission. Rates are extraordinarily low at this time. The following table offers a look at approximate FFB rates as of March 14, 2013.

APPROXIMATE FFB QUARTERLY RATES (3/5/13)									
3-mo	6-mo	1-yr	2-yr	3-yr	5-yr	7-yr	10-yr	20-yr	30-yr
0.09	0.14	0.18	0.30	0.47	0.93	1.41	1.96	2.61	2.76

Current rates can be seen at any time by following the link below:

Current Interest Rates

WHAT'S INSIDE

ISSUE HIGHLIGHTS

In December, the **High Energy Cost Grant Program (HECG)** awarded $9.3 million in funding to eight entities throughout the United States. Grants were available to communities with energy costs of 275% or higher than the national average, and awards ranged from $2.5M to $175,000. Please click here for the official press release. The 2013 HECG funding announcement will be published in the next few months; please watch our website and grants.gov for additional information. The application will be very similar to the 2012 grant application, applicants will again have 30 days to complete and submit their application.

Retirements: The end of the calendar year saw numerous retirements within the Electric Program. We would like to take this opportunity to congratulate each of them and wish them much happiness and success as they enter this new phase of their lives. The retirees included:

- Georg Shultz, Director, Electric Staff Division
- Bill Wallace, Senior Loan Specialist, Southern Regional Division
- Steve Slovikosky, Chief, Power Delivery Engineering Branch, Power Supply Division
- Bill Frost, Loan Specialist Northern Regional Division
- Bill McDevitt, General Field Representative, Northern Regional Division

Congratulations and best wishes!

"RUS has been serving rural America for over 77 years. During that time, our environment has changed. To continue to meet critical infrastructure needs of our rural communities, RUS needs to modernize. We look to three essential core values - customer service, constant process improvement and creativity - to guide us as we work to make delivery of our programs more effective and efficient."

CULTURAL TRANSFORMATION

As part of USDA's cultural transformation initiative, the Electric Program would like to take this opportunity to recognize the following employees who received awards for their outstanding service to rural America.

Sara Jordan, Senior Loan Specialist in the Northern Regional Division (NRD), was selected as RUS employee of the month for the successful closing of the Jefferson County PUD (Washington) loan. This loan enabled the acquisition of electric system assets and would help keep power rates affordable in rural communities in the service area.

Charles Philpott, Engineering Branch Chief in NRD, was selected as RUS employee of the month for providing exceptional engineering assistance to all Electric Program divisions enabling additional loans to be successfully obligated.

Doug Jenkins, Senior Loan Specialist in NRD, received the Administrator's Award for his work in completing two renewable energy project loans: the Kauai Green Energy Team's (Hawaii) biomass project and Southern Maryland Electric Cooperative's photovoltaic project. Doug's efforts focused on the program's high priority goal of enabling renewable energy projects to be developed so that benefits can be realized in rural communities.

Congratulations and thank you!

RUS ELECTRIC STREAMLINING EFFORTS

The RUS streamlining committee remains active evaluating staff suggestions to eliminate unneeded tasks internally and remove outdated and unnecessary borrower requirements. To date the team has reviewed 63 suggestions. We have implemented 14 efficiency changes and are currently working on the implementation of 27 more approved suggestions. Changes implemented thus far have reduced the information required in the RUS loan application, eliminated steps in loan processing, and improved the effectiveness of internal computer systems.

The committee has approved changes in the implementation process which will reduce the number of transactions requiring RUS approval. These changes will impact rules requiring RUS approval of some power supply contracts and the retirement of patronage capital. Other changes will further streamline the loan application package, reduce needed copies of some contracts, and streamline the process of loan closing.

RUS ELECTRIC SUCCESS STORIES

This quarter we would like to highlight Wright-Hennepin Cooperative Electric Association (Wright-Hennepin) which has entered into an agreement with Clean Energy Collective (CEC) to successfully launch the state of Minnesota's first community solar project. The first phase is a 40 kW array located at Wright-Hennepin's headquarters in Rockford, Minnesota. The project has received a great deal of interest and has been covered by both the Star Tribune and USA Today.

The concept is relatively simple. Members who might not be willing to finance the cost of upgrades at their homes and deal with the related hassle factors relating to maintenance, upkeep and repair may now may take advantage of clean, renewable solar energy. Members can purchase individual panels for $869 and will receive monthly bill credits for the power produced. The payback period is anticipated to be 20 years. CEC administers the program and warranties each panel for 50 years, leaving the customer free from concerns relating to construction, maintenance and repair. As of February, Wright-Hennepin had sold 171 panels. Congratulations Wright-Hennepin on the implementation of this successful new program!

Please contact Wright-Hennepin directly if interested in additional details on this program.

PROGRAM DEVELOPMENT AND REGULATORY ACCOUNTING

"No winter lasts forever; no spring skips its turn."

- Hal Borland

Submission of Annual CPA Audit Reports

As we enter 2013, just a reminder that borrowers with a December 31, 2012, audit date face a submission deadline of April 30, 2013. We would like to encourage all of our borrowers to submit their audits electronically through the Data Collection System (DCS) using their eAuthIDs. Directions for submitting audits electronically can be found in our letter dated June 17, 2010. We are providing a link at the end of this article to the letter which is posted on the RUS web-site. To access DCS, follow this link to the log in screen - DCS . Using DCS to submit your audit provides a secure and immediate upload, reducing your costs by eliminating the need to have your auditor provide three copies of the audit and by eliminating postage/shipping charges. It also ensures that the audit will land on the right desk and get priority processing.

Electronic Submission of Audited Financial Statements through DCS

PARA Staff Changes

There have been several recent staff changes in PARA. Three employees recently retired. Nancy Bonham, who served as a Senior Staff Accountant in PARA's Southern Region Accounting Branch since 2005 and served for one year as the Field Accountant for Iowa, retired on 1/30/13. Steve Duffy, who served as the Field Accountant for Kansas and as a floater Field Accountant throughout the country, retired on 1/25/13. Bob Lacomb, who served as the Field Accountant for Florida and Southern Georgia since 1985, retired on 12/28/12. We wish each one a very happy retirement. Jeff Stover, who served as the Field Accountant for North Carolina, took over as the Field Accountant for Florida and Southern Georgia effective 2/25/13. Any borrower in Kansas or North Carolina should refer all questions to Ms. Jurleme Grey, Chief, Southern Region Accounting Branch until the Field Accountants in these states are replaced. Ms. Grey can be contacted by email at: Jurleme.grey@wdc.usda.gov

CUSTOMER SERVICE

The Electric Program remains committed to providing outstanding customer service to our borrowers. We have undertaken a thorough review of our regulations and processes to identify requirements which no longer add value. As part of this analysis, staff reviewed the requirements pertaining to the Long Range Engineering Plan (LRP). The LRP, which provides support to a borrower's construction work plan (CWP), is an outstanding long-term planning tool required by both 7 CFR 1710.250 as well as borrower loan contracts. The CWP is an integral part of the loan underwriting process and is reviewed and approved by Electric Program staff.

RUS has determined that the requirement for the borrower to maintain a board approved LRP continues to provide a definitive value to both RUS and the borrower. However, it has been determined that RUS review and acceptance of the LRP is duplicative. In a March 12, 2013 letter to all borrowers, Nivin Elgohary provided notification that the borrower requirement to maintain an LRP will remain in place, however, RUS will no longer review and accept the LRP. Please feel free contact your assigned GFR if you have any questions.

GENERAL FIELD REPRESENTATIVES

After nearly 40 years of REA/RUS service, including the past 36 years as GFR in Ohio, Bill McDevitt, retired effective January 2013. We want to take this opportunity to thank Bill for his hard work and service and wish him the best in retirement.

We have temporarily assigned the following GFRs to cover Bill's assignments. Shelli Richardson (Virginia) has been assigned West Virginia. Aaron Johnson (Illinois) has been assigned to Bill's borrowers in Michigan and northwestern Ohio. Mike Norman (Kentucky) has been assigned Bill's remaining Ohio borrowers. Please visit the following link to view contact information for all Electric Program's GFRs: GFR Contact Information If you have specific questions regarding Bill's reassignments, please e-mail Northern Regional Director Joe Badin

ENGINEERING & ENVIRONMENTAL NEWS

"In the spring, I have counted 136 different kinds of weather inside of 24 hours."

- Mark Twain

Renewable Energy and Distributed Generation: The Electric Program fully supports the development of renewable energy projects and the implementation of distributed generation resources. RUS is aware of several noteworthy examples where Iowa borrowers provided leadership and innovation in integrating small, renewable distributed generation projects into their power supply mix. 7 CFR 1730, Subpart C - Interconnection of Distributed Resources provides guidance regarding interconnection of such facilities to an RUS borrower. Borrowers are required to formally adopt and publish a written interconnection policy that it is readily available to the public. The regulation allows borrowers the flexibility to develop the appropriate policy based on their system. It should be noted that, while Subpart C does not set a cap on the level of renewables or distributed generation allowed to interconnect, it is incumbent on the individual distribution borrowers to ensure that they remain in full compliance with the terms of their respective wholesale power contracts.

Power Supply Contract Approvals: RUS has become aware of several instances where borrowers have executed or amended power purchase contracts or other related power supply agreements without providing proper notification or receiving prior RUS approval. RUS requirements are clearly set forth in 7 CFR Part 1717.608 (c) - RUS Approval of Contracts - Power Supply Arrangements. If you have any questions or require any clarifications regarding these requirements, please contact either your assigned GFR or the appropriate RUS Regional Office or Power Supply Division.

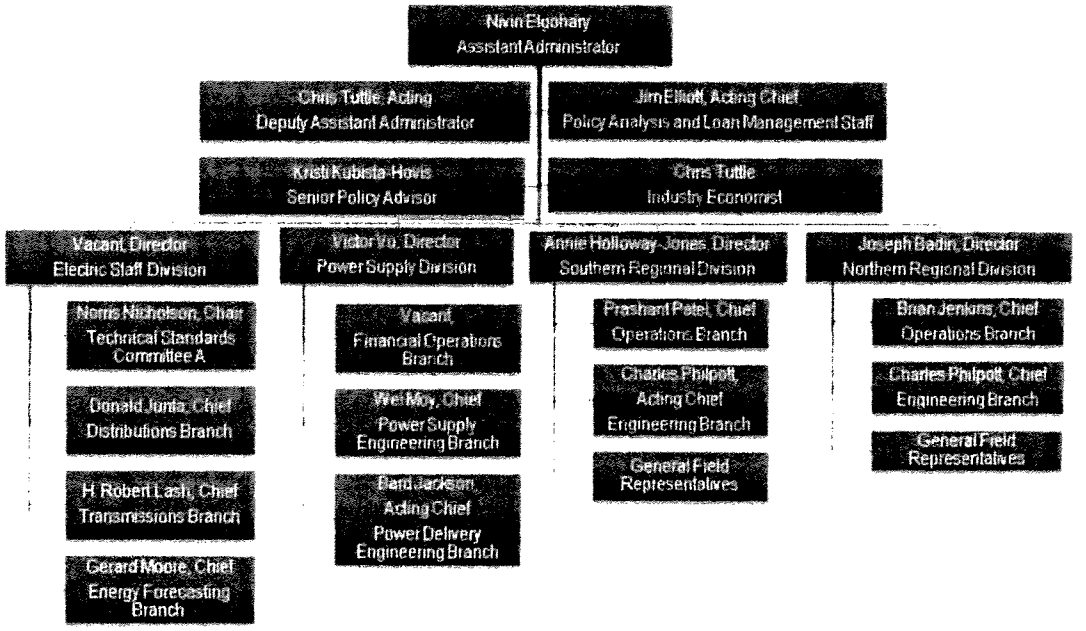
Environmental Review Process for the New Energy Efficiency and Conservation Loan Program: RUS is undergoing a rulemaking that will promulgate policies and procedures for a new loan program – the Energy Efficiency and Conservation Loan Program (EECLP). The rule will be Subpart H, 7 CFR part 1710, *General and Pre-Loan Policies And Procedures Common To Electric Loans And Guarantees*. The EECLP will enable eligible RUS borrowers to finance and implement eligible activities for the benefit of rural consumers in their service territories. Under Subpart H, the electric utilities could act as intermediary lenders for eligible activities by providing financial assistance to their rural consumers.

To apply for EECLP funds, eligible RUS borrowers would submit an EECLP Work Plan (WP) and the supporting documents. One of the supporting documents for the WP would be an Environmental Report (ER). To more efficiently evaluate the environmental considerations of the EECLP, RUS has prepared a Programmatic Environmental Assessment (PEA). The PEA was published in the Federal Register on February 6, 2013 and the comment period closed on March 8, 2013.

Once completed, the evaluation of specific environmental resources that would ordinarily be reviewed in an WP ER will be unnecessary since the PEA will have made a programmatic determination regarding the specific and general categories of eligible EECLP activities which do not have the potential to significantly affect resources. Additionally, RUS is creating an EECLP Environmental Compliance Tool Kit (Tool Kit). The core component of the Tool Kit will be an interactive fillable Abode Portable Document Format (PDF) document that will generate specific environmental compliance information based on project information input by the applicant. For example, if an applicant inputs information stating that EECLP funds will include re-lamping or standard interior weatherization activities, a statement will be automatically generated that concludes that RUS has evaluated these activities in the PEA and determined that they will not have the potential for adverse environmental effects for each resource topic in the ER document. Conversely, inputting information to state that EECLP funds will be used for small-scale wind turbines will generate further questions and/or may require that you contact RUS environmental staff for further guidance on completing the environmental review for that particular action. Ultimately, user-inputted information will populate the various fields in the PDF document and the output will be a printable PDF document that will become the applicant's ER to support the WP.

RUS is developing Tool Kit templates for specific agency and stakeholder letters that may be necessary for ERs that require notifications for specific actions. The Tool Kit will be updated as RUS environmental staff learn more about the types of activities that our borrowers will include in their WPs and as technology improves. Applicant input is critical to the continuing enhancement of the Tool Kit and RUS invites any comments that will help us help our borrowers increase the efficiency of the environmental review process for the EECLP.

RUS ELECTRIC STAFF ORGANIZATIONAL CHART



CONTACT US

USDA
Rural Development
Rural Utilities Service Electric Program
1400 Independence Avenue, SW
Mail Stop 1560
Washington, DC 20250
Phone: 202-720-9545
Fax: 202-690-0717

Email: RUSElectricQuarterlyNewsletter@wdc.usda.gov

FOLLOW USDA

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2013-00199

Response to the Kentucky Industrial Utility Customers, Inc.'s
Second Request for Information
dated September 16, 2013

September 30, 2013

Item 53) ***Please refer to the Company's response to KIUC 1-8 (d). Please provide a "yes" or "no" response.***

Response) Please refer to Big Rivers' response to KIUC 1-8 (b). Notwithstanding this response, presented with an opportunity to sell Wilson or Coleman, Big Rivers would perform an analysis of the proposed sales transaction to include the review of indenture and debt covenant compliance; impact on Big Rivers' equity; amount of debt retired and impact on future operations. There is no simple straight-forward "yes" or "no" response.

Witness) Robert W. Berry

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2013-00199

Response to the Kentucky Industrial Utility Customers, Inc.'s
Second Request for Information
dated September 16, 2013

September 30, 2013

Item 54) ***Refer to the Company's response to KIUC 1-8(e). Please respond to the question posed. The response merely cited to the response to PSC 2-15, which generally describes the status of negotiations to sell the Company's generating stations and the prices at which they have been offered. PSC 2-15 does not address the Company's bidding strategy and/or guidelines for the sale of Wilson and Coleman plants or the output of the plants, which is what was requested in KIUC 1-8(e).***

Response) Big Rivers has no such written documents.

Witness) Robert W. Berry

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2013-00199

Response to the Kentucky Industrial Utility Customers, Inc.'s
Second Request for Information
dated September 16, 2013

September 30, 2013

Item 55) ***Refer to the Company's response to KIUC 1-9(c), which asked if the Company had set a minimum sales prices of something greater than net book value and to provide related documents. The Company's response referred to its response to PSC 2-16; however, that response does not answer KIUC 1-9(e). Please response to KIUC 1-9(e) with a "yes" or "no" answer and then any relevant explanation and copies of the documents requested.***

Response) Please see Big Rivers' response to KIUC 2-53.

Witness) Robert W. Berry

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2013-00199

Response to the Kentucky Industrial Utility Customers, Inc.'s
Second Request for Information
dated September 16, 2013

September 30, 2013

Item 56) ***Please refer to the Company's response to KIUC 1-10, which sought all studies "to assess the economic viability of the Wilson and Coleman plants and the timing of their return to service." The Company's response referred to the response to PSC 2-14. PSC 2-14 cited the Company's PCM and most recent financial model. In Case No. 2012-00535, the Company provided a plant by plant net margin analysis. Please indicate whether the Company has a similar analysis based on its projections in this proceeding. If so, please provide a copy of it in electronic format with all formulas intact. In addition, either confirm that the Company has conducted no other economic studies or provide all such studies in accordance with KIUC 1-10.***

Response) In Case No. 2012-00535, the plant by plant gross margin analysis provided was the PCM runs. The PCM runs for this case have been provided also. Please see Big Rivers' response to KIUC 2-14 and the two PCM runs that are referenced. The gross margins by unit for the variable costs can be found on the "Annual ISO Style Costs" and the "ISO Style Costs" on the PCM runs. The PCM runs, the financial model, and the fixed cost savings analysis, which have all been provided, constitute the economic studies that have been completed.

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2013-00199

Response to the Kentucky Industrial Utility Customers, Inc.'s
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dated September 16, 2013

September 30, 2013

Witness) Robert W. Berry

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2013-00199

Response to the Kentucky Industrial Utility Customers, Inc.'s
Second Request for Information
dated September 16, 2013

September 30, 2013

Item 57) ***Please supply a copy of the Company's most recent IRP, and state whether it included an assumption that the Company would acquire hundreds of MWs of new load between 2014 and 2027. If not, please explain why not.***

Response) Big Rivers filed its most recent IRP on November 15, 2010, in Case No. 2010-00443, and it is available on the Public Service Commission's website at the following link: http://www.psc.ky.gov/Home/Library?type=Cases&folder=2010%20cases/2010-00443. The IRP was prepared and filed in 2010, at least two years before either smelter gave notice to terminate its contract, and as such, well before Big Rivers had significant capacity and energy available to offer. Hence there was no need to assume Big Rivers would actively and aggressively attempt to acquire hundreds of MWs of new load between 2014 and 2027 in the most recent IRP.

Witness) Lindsay N. Barron

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2013-00199

Response to the Kentucky Industrial Utility Customers, Inc.'s
Second Request for Information
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September 30, 2013

Item 58) ***If the Company has a written plan or written instructions to employees about how they should be actively marketing for new load, please supply all documentation that may exist.***

Response) Big Rivers' Load Concentration Analysis and Mitigation Plan outlines Big Rivers' general strategy for load replacement. No additional written plans or instructions to Big Rivers' employees exist.

Witness) Robert W. Berry

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2013-00199

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Item 59) ***Please provide a market price forecast, consistent with the 2014 - 2027 forecast that the Company already developed in this case, but which includes CO2 impacts. Please provide all workpapers including original source data and the calculations used to derive the final hourly market price forecasts. Please also provide all workpapers required to convert the forecast into PAR hourly input format. Please supply the natural gas and coal price forecasts that are consistent with the CO2 market price forecast. Please provide all assumptions associated with the CO2 forecast including the annual CO2 forecast that was assumed. Please provide all of this information electronically with all formula intact.***

Response) A market price forecast that includes CO2 impacts has not been requested by Big Rivers from ACES for its production cost modeling because the generation production cost inputs do not include any CO2 impacts.

Witness) Robert W. Berry

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Item 60) ***If a market price forecast with CO2 impacts considered that is consistent with the forecast derived in the Alcan case is not available, please provide the most recent pair of long term market price forecasts that the Company has used for any production cost modeling purpose, one with CO2 impacts included and the other without the CO2 impacts included. In addition, please provide all workpapers, including original source data and the calculations used to derive the final hourly market price forecasts. Please also provide all workpapers required to convert the forecasts into PAR hourly input format. Please supply the natural gas and coal price forecasts that are consistent with these market price forecasts. Please provide all assumptions associated with the CO2 forecast including the annual CO2 forecast that was assumed. Please provide all of this information electronically with all formula intact.***

Response) Please see Big Rivers' response to KIUC 2-6 for an explanation of why Big Rivers utilized a market price forecast without CO2 impacts. The most recent production cost model (PCM) performed was for producing the 2014 budget and 2015 – 2017 financial plan. The market price forecasts used in the 2014 budget PCM run were the same as the price forecasts used for the PCM runs in Case No. 2013-00199.

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Item 61) ***Please clarify what is meant in the response to AG 1-76 in which it states Wilson costs are excluded from the O&M, PCM, and Fuel worksheets in the financial model. Does that mean in the financial model no Wilson costs are included at all, or that in the attachment to the Company's response to AG 1-76, certain costs for Wilson have been excluded, while other costs for Wilson have been included?***

Response) Big Rivers' response to AG 1-76 indicated that operating costs for the Wilson plant were excluded from the costs provided for the financial model. However, Wilson will be in an idled status during the time frame mentioned in Big Rivers' response to AG 1-76. The idled status costs for the Wilson plant are included on the O&M worksheet in the financial model provided in Big Rivers' response to PSC 1-57. Also, please see Big Rivers' response to KIUC 2-15, which shows costs for Wilson from 2014-2027.

Witness) Christopher A. Warren

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Item 62) ***The Company's response to AG 1-76 contains a table of Plant Layup Savings given the Alcan revenue loss.***

a. ***Please provide detailed annual calculations and supply work papers of the Alcan revenue loss, and source all spreadsheets down to the identification of specific cells indicating where the data came from to calculate the Plant Layup savings.***

b. ***Please repeat the above response, but provide the same information for each of the savings items including Variable Costs, Wilson Non-Labor Expenses, and Wilson Labor Reduction.***

c. ***Please provide all information identified above electronically with all formula intact.***

Response)

a. Please refer to the financial report to the board provided in response to Tab 35 of the Application, for the month December 2012. Pages 7-9 show the year-to-date smelter revenue, variable cost, and margin that was used in the table contained in Big Rivers' response to AG 1-76. The smelter portion contains Century and Alcan, but the total margin can be determined by adding the

Alcan margin plus the Century margin: $155 million Alcan revenue, less the $83 million variable cost, equals $72 million gross margin, plus the $92 million Century gross margin, equals the amount, sans rounding, shown as the gross sales margin on the December 2012 financial report for the board of $163 million.

b. Please refer to Big Rivers' response to subpart (a) above for variable costs. For non-labor and labor expenses for Wilson, please refer to Big Rivers' response to KIUC 2-25.

c. Please refer to Big Rivers' response to KIUC 2-25.

Witness) Robert W. Berry

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Item 63) ***Please provide the same information (including each subpart of the immediately prior question) for Plant Layup Savings associated with the Century revenue loss.***

Response) Please refer to Big Rivers' response to AG 2-31(g).

Witness) Robert W. Berry

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Item 64) ***The Company was asked in Staff 2-14 for the Company's analysis or study to support the decision when to return idled units to operational status. Where in the response is such an analysis provided? How did the Company make its decision concerning the optimal years for which to return the units to service. Please supply the missing analysis electronically with all formula intact, and explain how the Company determined the optimal time for returning the units to service. If no analysis was conducted, please supply a one word response either yes or no answering whether a study was conducted.***

Response) Please see Big Rivers' responses to KIUC 2-14 and KIUC 2-56. Also, as stated in Big Rivers' response to PSC 2-14, the timing for returning the units to service is very dynamic and depends on the market power prices, Big Rivers' load recovery, and MISO capacity pricing. The reliability of the transmission system also plays a role in determining when units are idled or returned to service. Any new environmental regulations, fuel pricing, reagent pricing, disposal costs, etc., that impact the production cost will factor into the decision. Big Rivers' decision to idle generating stations or return units to service will be made to provide its Members with the lowest rates possible.

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Item 65) ***The Company's response to AG 1-195 and AG 1-201 gives an allocation of gross interest expense to Wilson and Coleman, respectively. The Company also provided an allocation of interest expense by plan to Wilson and Coleman in its responses to KIUC 1-21 and 1-22. Please reconcile the differences in the allocations in these responses.***

Response) Big Rivers' responses to AG 1-195 and AG 1-201 reflect interest on long term debt of $45,032,787. Big Rivers' responses to KIUC 1-21 and KIUC 1-22 reflect interest on long term debt and other interest expense of $45,141,957. The same percentage allocation was used in all responses: approximately 15% at Coleman and 48% at Wilson.

Witness) Jeffrey R. Williams

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Item 66) ***Concerning the Company's response to AG 1-105:***

a. ***Please supply a workpaper identifying where the data may be found that was used to calculate the $73 million in fixed costs that will be saved during 2014 through 2016 by idling Wilson.***

b. ***Please supply a workpaper identifying where the data may be found that was used to develop the table that was attached to AG 1-105.***

c. ***Please provide the above information electronically with all formula intact.***

Response)

a. Please reference Big Rivers' response to KIUC 2-25.

b. Please reference Big Rivers' response to KIUC 1-21.

c. Please reference Big Rivers' response to KIUC 2-25.

Witness) Robert W. Berry

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Item 67) ***Concerning the Company's response to AG 1-106:***

a. ***Please supply a workpaper identifying where the data may be found that was used to calculate the $78 million in fixed costs that will be saved during 2014 through 2016 by idling Coleman.***

b. ***Please supply a workpaper identifying where the data may be found that was used to develop the table that was attached to AG 1-106.***

c. ***Please provide the above information electronically with all formula intact.***

Response)

a. Please reference Big Rivers' response to KIUC 2-25.

b. Please reference Big Rivers' response to KIUC 1-21.

c. Please reference Big Rivers' response to KIUC 2-25.

Witness) Robert W. Berry