ORIGINAL

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

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

Response to Commission Staff's
Second Request for Information
dated February 14, 2013

FILED: February 28, 2013

ORIGINAL

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RECEIVED
FEB 28 2013
PUBLIC SERVICE COMMISSION

February 28, 2013

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

In The Matter Of: *Application of Big Rivers Electric Corporation For A General Adjustment In Rates - Case No. 2012-00535*

Dear Mr. DeRouen:

Enclosed for filing are an original and ten (10) copies of (i) the response of Big Rivers Electric Corporation to the Public Service Commission Staff's Second Request for Information and the intervenor's first requests for information; (ii) a petition for confidential treatment for certain of the responses; and (iii) a Motion for Deviation. Please note that since the Commission has not ruled on the petition to intervene filed by Ben Taylor and the Sierra Club, Big Rivers is not responding to their information requests or sending them copies of the responses to the information requests that Big Rivers is responding to.

Copies of the responses, the petition, and the motion have been served on those parties listed on the attached service list by Federal Express or hand delivery.

Sincerely,

TK

Tyson Kamuf

cc: Service List
Billie J. Richert

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BIG RIVERS ELECTRIC CORPORATION

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

VERIFICATION

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

Mark A. Bailey
Mark A. Bailey

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Mark A. Bailey on this the 27 day of February, 2013.

Joy P. Wright
Notary Public, Ky. State at Large
My Commission Expires________

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

BIG RIVERS ELECTRIC CORPORATION

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

VERIFICATION

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

Billie J. Richert

Billie J. Richert

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Billie J. Richert on this the 27 day of February, 2013.

Joy P. Wright

Notary Public, Ky. State at Large
My Commission Expires_______

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

BIG RIVERS ELECTRIC CORPORATION

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

VERIFICATION

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

Robert W Berry
Robert W. Berry

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Robert W. Berry on this the 27 day of February, 2013.

Joy P. Wright
Notary Public, Ky. State at Large
My Commission Expires_______

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

BIG RIVERS ELECTRIC CORPORATION

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

VERIFICATION

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

Lindsay N. Barron

Lindsay N. Barron

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Lindsay N. Barron on this the 27 day of February, 2013.

Joy P. Wright

Notary Public, Ky. State at Large
My Commission Expires________

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

BIG RIVERS ELECTRIC CORPORATION

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

VERIFICATION

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

David G. Crockett
David G. Crockett

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by David G. Crockett on this the 27 day of February, 2013.

Joy P. Wright
Notary Public, Ky. State at Large
My Commission Expires_______

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

BIG RIVERS ELECTRIC CORPORATION

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

VERIFICATION

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

James V. Haner

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by James V. Haner on this the 27 day of February, 2013.

Jay P. Wright
Notary Public, Ky. State at Large
My Commission Expires________

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

BIG RIVERS ELECTRIC CORPORATION

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

VERIFICATION

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

DeAnna M. Speed
DeAnna M. Speed

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by DeAnna M. Speed on this the 27 day of February, 2013.

Joy P. Wright
Notary Public, Ky. State at Large
My Commission Expires________

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

BIG RIVERS ELECTRIC CORPORATION

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

VERIFICATION

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

John Wolfram

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by John Wolfram on this the 26th day of February, 2013.

Notary Public, Ky. State at Large
My Commission Expires 8-9-2014

BIG RIVERS ELECTRIC CORPORATION

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

VERIFICATION

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

Ted J. Kelly

Ted J. Kelly

STATE OF MISSOURI)
COUNTY OF JACKSON)

SUBSCRIBED AND SWORN TO before me by Ted J. Kelly on this the 27 day of February, 2013.

NOTARY PUBLIC
NOTARY SEAL
STATE OF MISSOURI

PAULA M. ANNAN
My Commission Expires
January 19, 2015
Jackson County
Commission #11992872

Paula M Annan
Notary Public
State of Missouri
My Commission Expires 1-19-15

BIG RIVERS ELECTRIC CORPORATION

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

VERIFICATION

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

Travis A. Siewert

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Travis A. Siewert on this the 26th day of February, 2013.

Notary Public, Ky. State at Large
My Commission Expires 8-9-2014

BIG RIVERS ELECTRIC CORPORATION

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

Response to Commission Staff's Second Request for Information dated February 14, 2013

February 28, 2013

Item 1) ***Refer to the Notice of Termination of Alcan Primary Products Corporation ("Alcan") of its Retail Electric Service Agreement with Kenergy Corp. filed by Alcan on January 31, 2013. Explain in detail the implications of this notice for Big Rivers and what impact, if any, Big Rivers expects it to have on this rate proceeding.***

Response) Big Rivers is in the process of evaluating the implications of the Alcan termination notice on Big Rivers, but it should have no impact on this rate proceeding. As explained in Big Rivers' direct testimony, Big Rivers needs the rate relief sought in this proceeding beginning August 20, 2013. The termination of Alcan's retail power contract is effective January 31, 2014. Big Rivers will file a separate proceeding in June of 2013 to address the Alcan contract termination to the extent Big Rivers needs additional rate relief beginning January 31, 2014. Thus, Big Rivers sees no reason why the Alcan termination notice should impact this proceeding.

Witness) Billie J. Richert

BIG RIVERS ELECTRIC CORPORATION

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

**Response to Commission Staff's Second Request for Information
dated February 14, 2013**

February 28, 2013

Item 2) ***Refer to Tab 8 of the application.***

a. Refer to proposed PSC No. 25, Original Sheet No. 64, Section (l)(d). This section begins "The cost of fossil fuel, as denoted in (2)(a) above ..." Explain whether the reference in this sentence should be to (l)(a) instead of (2)(a).

b. Refer to proposed PSC No. 25, Original Sheet No. 65, Section (3)(v) which refers to "subsection (2)(d) above.. . " Explain whether the reference in this section should be to (l)(d) instead of (2)(d).

Response)

a. The reference in this sentence should be to (l)(a) instead of (2)(a).

b. The reference in this section should be to (l)(d) instead of (2)(d).

Witness) Travis A. Siewert

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

Response to Commission Staff's Second Request for Information
dated February 14, 2013

February 28, 2013

Item 3) ***Refer to Exhibit 10 of the application, the comparison of present and proposed rates. Explain how the \$3.955 demand charge was calculated for the Cogeneration/Small Power Sales – Over 100 kW tariff.***

Response) The demand charge for the Cogeneration/Small Power Sales – Over 100 kW tariff is determined by converting the demand charge for the Rural Delivery Service ("RDS") tariff from \$/kW-month to \$/kW-week. The rate was calculated by dividing the \$16.95/kW-month RDS by thirty (approximating the number of days in a month) and multiplying by seven (for the number of days in a week).

{16.95 \$/kW-month} / {30 days/month} x {7 days/week} = 3.955 \$/kW-week

This is the same approach Big Rivers used in its last rate case, Case No. 2011-00036.

Witness) John Wolfram

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

**Response to Commission Staff's Second Request for Information
dated February 14, 2013**

February 28, 2013

Item 4) ***Refer to Tab 20 of the application which shows the base-period statement of operations with adjustments and the forecast-period statement of operations. The base period ending April of 2013 includes six months (May 2012 through October 2012) of historical data and six months (November 2012 through April 2013) of estimated data. Provide an updated base-period statement of operations which includes nine months of actual data (May 2012 through January 2013) and three months of estimated data (February 2013 through April 2013).***

Response) Attached is the updated base-period statement of operations which includes nine months of actual data (May 2012 through January 2013) and three months of estimated data (February 2013 through April 2013).

Witness) DeAnna M. Speed

Big Rivers Electric Corporation
Case No. 2012-00535

Attachment for Response to PSC 2-4
Statement of Operations
Base Period with Adjustments to Forecast Period

Line Item	May-2012 Actuals	Jun-2012 Actuals	Jul-2012 Actuals
Electric Energy Revenues	$48,310	$46,967	$50,686
Other Operating Revenue and Income	$380	$503	$567
Total Oper Revenues & Patronage Capital	$48,690	$47,470	$51,253
Operation Expense-Production-excl fuel	$4,063	$3,967	$4,185
Operation Expense-Production-Fuel	$20,412	$19,401	$21,590
Operation Expense-Other Power Supply	$8,773	$7,966	$8,667
Operation Expense-Transmission	$1,080	$633	$954
Operation Expense - RTO/ISO	$195	$180	$139
Operation Expense - Customer Accounts	$0	$0	$0
Consumer Service & Informational Expense	$22	$47	$90
Operation Expense - Sales	$5	$10	$5
Operation Expense - Administrative & General	$1,923	$3,270	$2,004
Total Operation Expense	$36,473	$35,474	$37,634
Maintenance Expense-Production	$2,627	$2,679	$3,350
Maintenance Expense-Transmission	$391	$539	$450
Maintenance Expense-General Plant	$21	$25	$1
Total Maintenance Expense	$3,039	$3,243	$3,801
Depreciation & Amortization Expense	$3,392	$3,392	$3,404
Taxes	$0	$0	$0
Enterest on Long-Term Debt	$3,815	$3,706	$3,680
Interest Charged to Construction-Credit	($65)	($57)	($59)
Other Interest Expense	$0	$0	$11
Other Deductions	$27	$12	$15
Total Cost of Electric Service	$46,681	$45,770	$48,486
Operating Margins	$2,009	$1,700	$2,767
Interest Income	$4	$4	$6
Allowance for Funds Used during Const	$0	$0	$0
Other Non-Operating Income - net	$0	$0	$0
Other Capital Credits & Pat Dividends	$0	$0	$0
Extraordinary Items	$0	$0	$0
Net Patronage Capital or Margins	$2,013	$1,704	$2,773

Big Rivers Electric Corporation
Case No. 2012-00535

Attachment for Response to PSC 2-4
Statement of Operations
Base Period with Adjustments to Forecast Period

Line Item	Aug-2012 Actuals	Sep-2012 Actuals	Oct-2012 Actuals
Electric Energy Revenues	$48,521	$46,264	$46,001
Other Operating Revenue and Income	$532	$351	$409
Total Oper Revenues & Patronage Capital	$49,053	$46,615	$46,410
Operation Expense-Production-excl fuel	$4,332	$4,038	$3,682
Operation Expense-Production-Fuel	$19,183	$18,170	$18,171
Operation Expense-Other Power Supply	$8,465	$8,973	$10,860
Operation Expense-Transmission	$805	$626	$903
Operation Expense - RTO/ISO	$128	$170	$191
Operation Expense - Customer Accounts	$0	$0	$0
Consumer Service & Informational Expense	$41	$61	$96
Operation Expense - Sales	$72	$5	$39
Operation Expense - Administrative & General	$2,474	$2,107	$1,331
Total Operation Expense	$35,500	$34,150	$35,273
Maintenance Expense-Production	$4,096	$3,000	$3,761
Maintenance Expense-Transmission	$614	$338	$333
Maintenance Expense-General Plant	$17	$17	$14
Total Maintenance Expense	$4,727	$3,355	$4,108
Depreciation & Amortization Expense	$3,521	$3,564	$3,396
Taxes	$0	$0	$0
Enterest on Long-Term Debt	$3,851	$3,704	$3,809
Interest Charged to Construction-Credit	($65)	($70)	($70)
Other Interest Expense	$44	$0	$0
Other Deductions	$26	$24	$71
Total Cost of Electric Service	$47,604	$44,727	$46,587
Operating Margins	$1,449	$1,888	($177)
Interest Income	$19	$348	$174
Allowance for Funds Used during Const	$0	$0	$0
Other Non-Operating Income - net	$0	$0	$0
Other Capital Credits & Pat Dividends	$14	$0	$0
Extraordinary Items	$0	$0	$0
Net Patronage Capital or Margins	$1,482	$2,236	($3)

Big Rivers Electric Corporation
Case No. 2012-00535

Attachment for Response to PSC 2-4
Statement of Operations
Base Period with Adjustments to Forecast Period

Line Item	Nov-2012 Actuals	Dec-2012 Actuals	Jan-2013 Actual
Electric Energy Revenues	$50,276	$47,926	$50,638
Other Operating Revenue and Income	$328	$361	$362
Total Oper Revenues & Patronage Capital	$50,604	$48,287	$51,000
Operation Expense-Production-excl fuel	$4,036	$3,943	$4,375
Operation Expense-Production-Fuel	$21,116	$21,249	$21,531
Operation Expense-Other Power Supply	$7,679	$8,646	$9,328
Operation Expense-Transmission	$818	$1,035	$771
Operation Expense - RTO/ISO	$215	$193	$238
Operation Expense - Customer Accounts	$0	$297	$0
Consumer Service & Informational Expense	$144	$256	$48
Operation Expense - Sales	$5	$45	$0
Operation Expense - Administrative & General	$2,098	$2,622	$1,751
Total Operation Expense	$36,111	$38,286	$38,042
Maintenance Expense-Production	$3,252	$3,285	$3,304
Maintenance Expense-Transmission	$237	$302	$279
Maintenance Expense-General Plant	$11	$31	$23
Total Maintenance Expense	$3,500	$3,618	$3,606
Depreciation & Amortization Expense	$3,417	$3,426	$3,414
Taxes	$0	$0	$0
Enterest on Long-Term Debt	$3,706	$3,799	$3,804
Interest Charged to Construction-Credit	($74)	($45)	($34)
Other Interest Expense	$46	$47	$0
Other Deductions	$167	$121	$35
Total Cost of Electric Service	$46,873	$49,252	$48,867
Operating Margins	$3,731	($965)	$2,133
Interest Income	$172	$214	$169
Allowance for Funds Used during Const	$0	$0	$0
Other Non-Operating Income - net	$0	$0	$0
Other Capital Credits & Pat Dividends	$0	$3	$0
Extraordinary Items	$0	$0	$0
Net Patronage Capital or Margins	$3,903	($748)	$2,302

Big Rivers Electric Corporation
Case No. 2012-00535

Attachment for Response to PSC 2-4
Statement of Operations
Base Period with Adjustments to Forecast Period

Line Item	Feb-2013 Budget	Mar-2013 Budget	Apr-2013 Budget
Electric Energy Revenues	[redacted]		
Other Operating Revenue and Income	$307	$307	$308
Total Oper Revenues & Patronage Capital	$46,665	$49,042	$44,116
Operation Expense-Production-excl fuel	[redacted]		
Operation Expense-Production-Fuel			
Operation Expense-Other Power Supply			
Operation Expense-Transmission			
Operation Expense - RTO/ISO			
Operation Expense - Customer Accounts			
Consumer Service & Informational Expense			
Operation Expense - Sales			
Operation Expense - Administrative & General			
Total Operation Expense			
Maintenance Expense-Production			
Maintenance Expense-Transmission			
Maintenance Expense-General Plant			
Total Maintenance Expense			
Depreciation & Amortization Expense	$3,442	$3,446	$3,451
Taxes	$0	$0	$1
Enterest on Long-Term Debt	$3,494	$3,929	$3,836
Interest Charged to Construction-Credit	($6)	($22)	($46)
Other Interest Expense	$0	$0	$0
Other Deductions	$38	$47	$45
Total Cost of Electric Service	[redacted]		
Operating Margins			
Interest Income	$170	$170	$168
Allowance for Funds Used during Const	$0	$0	$0
Other Non-Operating Income - net	$0	$0	$0
Other Capital Credits & Pat Dividends	$0	$1,238	$25
Extraordinary Items	$0	$0	$0
Net Patronage Capital or Margins	[redacted]		

Big Rivers Electric Corporation
Case No. 2012-00535

Attachment for Response to PSC 2-4
Statement of Operations
Base Period with Adjustments to Forecast Period

Line Item	Base Period	Adjustments	Forecasted Period Budget
Electric Energy Revenues	[redacted]		
Other Operating Revenue and Income	$4,715	($1,019)	$3,696
Total Oper Revenues & Patronage Capital	$579,205	($96,162)	$483,043
Operation Expense-Production-excl fuel	[redacted]		
Operation Expense-Production-Fuel			
Operation Expense-Other Power Supply			
Operation Expense-Transmission			
Operation Expense - RTO/ISO			
Operation Expense - Customer Accounts			
Consumer Service & Informational Expense			
Operation Expense - Sales			
Operation Expense - Administrative & General			
Total Operation Expense			
Maintenance Expense-Production			
Maintenance Expense-Transmission			
Maintenance Expense-General Plant			
Total Maintenance Expense			
Depreciation & Amortization Expense	$41,265	$2,838	$44,103
Taxes	$1	$0	$1
Enterest on Long-Term Debt	$45,133	$1,850	$46,983
Interest Charged to Construction-Credit	($613)	($1,867)	($2,480)
Other Interest Expense	$148	($148)	$0
Other Deductions	$628	($37)	$591
Total Cost of Electric Service	[redacted]		
Operating Margins			
Interest Income	$1,618	$358	$1,976
Allowance for Funds Used during Const	$0	$0	$0
Other Non-Operating Income - net	$0	$0	$0
Other Capital Credits & Pat Dividends	$1,280	$1,426	$2,706
Extraordinary Items	$0	$0	$0
Net Patronage Capital or Margins	[redacted]		

BIG RIVERS ELECTRIC CORPORATION

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

Response to Commission Staff's Second Request for Information
dated February 14, 2013

February 28, 2013

Item 5) Refer to Tab 25 of the application, pages 1-19, which include a breakdown of Big Rivers' 2013 and 2014 budgeted capital expenditures. Explain whether the amendment to Big Rivers' financing application in Case No. 2012-00492 would, if approved, impact the level of capital expenditures in 2013 or 2014.

Response) The amendment to Big Rivers' financing application in Case No. 2012-00492, if approved, would not impact the level of capital expenditures in 2013 or 2014.

Witness) Billie J. Richert

Item 6) ***Refer to Tab 55 of the application at page 1, specifically, the comparative income statements for 2010, 2011, the base period, the forecast period and calendar years 2015 and 2016. Big Rivers' maintenance expenses in 2010 and 2011 were $46.880 million and $47.718 million, respectively. The average maintenance expense in the four future periods is $45.898 million, and 2016 is the only future period in which the annual expense is greater than the actual amounts recorded in 2010 and 2011. Explain how this apparent "maintain the status quo" approach to Big Rivers' annual maintenance expense reflects its need to catch up on maintenance during the period 2013-2016, as discussed in the Direct Testimony of Robert W. Berry ("Berry Testimony") at pages 14-15.***

Response) The reason the comparative income statements contain similar amounts for maintenance expense in 2010-2016 is not because Big Rivers is "maintaining the status quo" but because the significant reduction in maintenance expense at Wilson during the period 2013 – 2016 while the plant is idled offsets increased maintenance at Big Rivers' other plants in those years. The average annual maintenance expense for Wilson in Big Rivers' 2012 – 2015 Production Business Plan was $[redacted]. The average annual maintenance expense for Wilson in the 2013 – 2016 Production Business Plan is $[redacted] or $[redacted] less. Big Rivers determined that it was necessary and prudent to reinvest that reduction in maintenance expense at Wilson across the remainder of its fleet in order to catch up on the maintenance that had been deferred in 2010, 2011, and 2012. Thus, while the overall Production Maintenance Expense is similar over the 2010-2016 timeframe, maintenance expense at each plant is not.

Witness) Robert W. Berry

BIG RIVERS ELECTRIC CORPORATION

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

Response to Commission Staff's Second Request for Information
dated February 14, 2013

February 28, 2013

Item 7) ***Refer to Tab 59 of the application.***

a. Refer to page 2 of 8. Provide the supporting calculation for the Smelter base fixed-energy rate of $.039405.

b. Refer to page 6 of 8. Provide the supporting calculation for the Smelter base fixed-energy rate of $.047597.

c. Refer to pages 6-8 of 8. Explain why the Environmental Surcharge rates and revenues on these three pages differ from those shown for each rate class in Exhibit Wolfram-5, pages 1 and 2 of 4.

Response)

a. The rate is simply the total "Revenue $" divided by the "Billing Units" shown on this page. It represents the overall effective rate for the actual billing period (5/1/2012 through 10/31/2012), forecasted billing period (11/1/2012 through 12/31/2012) and budgeted billing period (1/1/2013 through 4/30/2013).

b. The rate is simply the total "Revenue $" divided by the "Billing Units" shown on this page, for the fully forecasted test period (9/1/2013 through 8/31/2014).

c. The values on these pages differ slightly from those provided in Exhibit Wolfram-5 due to rounding. The rates were not rounded in the calculations in Exhibit Wolfram-5 but were rounded to the correct significant digits in Tab 59. This is addressed in the response to PSC 2-36.

Witnesses) Billie J. Richert and John Wolfram

Item 8) ***Refer to the Direct Testimony of Billie J. Richert ("Richert Testimony") at page 9, lines 2-5, and Exhibit Richert-2.***

a. ***Provide the <u>G&T Accounting and & Finance Association Annual Directory</u> dated June 2012.***

b. ***Besides Big Rivers, 25 cooperatives are included in Exhibit Richert-2. Identify which of those 25 cooperatives' rates are subject to the jurisdiction of a state regulatory commission.***

Response)

a. A copy of the G&T Accounting & Finance Association Annual Directory dated June 2012 is provided on the PUBLIC CDs accompanying these responses.

b. Please see the attachment to this response for a copy of Exhibit Richert-2, updated to include a column stating which utilities are subject to the jurisdiction of a state regulatory commission.

Witness) Billie J. Richert

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

	State Regulated	Moodys	Fitch	S&P	TIER or MFI
Golden Spread	Yes	NR	A	A(Stable)	3.17
Arkansas	Yes	A1	A+	AA-(Stable)	2.37
Central Iowa (Allegheny)	No	NR	A	A(Stable)	2.18
Brazos	Yes	NR	A	A-(Positive)	1.95
Corn Belt	No	NR	A-	A-(Stable)	1.88
Hoosier	No	A3	NR	A(Stable)	1.83
South Miss.	No	NR	A-	A-(Stable)	1.72
South Texas	Yes	NR	A-	A-(Stable)	1.70
San Miguel	No	NR	A-	A-(Stable)	1.57
Buckeye	No	A2	A	A-(Stable)	1.50
Associated	No	A1	AA	AA(Stable)	1.49
East Kentucky	Yes	NR	BBB	BBB(Stable)	1.48
Wabash Valley	No	NR	NR	A-(Stable)	1.47
Power South	No	NR	A-	A-(Stable)	1.44
Dairyland	No	A3	NR	A(Stable)	1.43
Minnkota	No	NR	NR	A-(Stable)	1.43
Seminole	No	NR	NR	A-(Stable)	1.41
Central-SC	No	NR	NR	AA-(Stable)	1.40
Chugach	Yes	NR	A-	A-(Stable)	1.30
Western Farmers	No	NR	A-	BBB+(Positive)	1.29
North Carolina	No	NR	A-	A-(Stable)	1.29
Basin	No	A1	A+	A(Stable)	1.26
Great River	No	Baa1	A-	A-(Stable)	1.22
Old Dominion	No	A3	A	A(Stable)	1.22
Oglethorpe	No	Baa1	A	A(Stable)	1.14
Average					**1.61**
Big Rivers	Yes	Baa2(Neg)	BBB-(Neg)	BBB-(Neg)	1.12

NR: No Rating

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

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

**Response to Commission Staff's Second Request for Information
dated February 14, 2013**

February 28, 2013

Item 9) ***Refer to the Richert Testimony at page 12, lines 4-10. Provide Big Rivers' net margins from off-system sales for calendar years 2011 and 2012.***

Response) The requested information is provided in the attachment to this response.

Witness) Billie J. Richert

Big Rivers Electric Corporation
Case No. 2012-00535
Attachment to Response for PSC 2-9
Off-System Margins 2011 - 2012

Off-System Net Margins		
	2011	2012
Actual Off-System MWh*	[redacted]	[redacted]
Actual Off-System $/MWh		
Actual Off-System Revenue		
Actual Off-System Variable Expense		
Net Actual Off-System Margin		

* Adjusted for Smelter surplus sales.

BIG RIVERS ELECTRIC CORPORATION

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

Response to Commission Staff's Second Request for Information dated February 14, 2013

February 28, 2013

Item 10) ***Refer to the Richert Testimony at page 14, line 20 through page 15, line 6, and the Direct Testimony of DeAnna M. Speed ("Speed Testimony") at page 18, lines 18-22. The Richert Testimony refers to "the budget for 2013 and 2014," while the Speed Testimony refers to the "2013 budget and the 2014-2016 financial plans" that were approved by the Big Rivers Board of Directors on November 16, 2012. Clarify whether or not a 2014 budget has been developed and approved by the Big Rivers board.***

Response) The terminology used in the Richert Testimony and Speed Testimony regarding "budget for...2014" and "2014...financial plans" is synonymous. The 2014 budget (also referred to as the 2014 financial plan) was developed and approved by the Big Rivers board.

Witness) DeAnna M. Speed

BIG RIVERS ELECTRIC CORPORATION

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

Response to Commission Staff's Second Request for Information dated February 14, 2013

February 28, 2013

Item 11) ***Refer to the Richert Testimony at page 24, lines 12-13. Provide Big Rivers' statement of operations (income statement) for calendar year 2012 and its 2012 budgeted statement of operations in comparative form.***

Response) Attached is the statement of operations (budget vs. actual) for the 2012 calendar year.

Witness) Billie J. Richert

Big Rivers Electric Corporation
Case No. 2012-00535

Attachment to Response PSC 2-11
Statement of Revenues and Expenses (unaudited)
YTD December 31, 2012

		BUDGET	CURRENT YEAR	VARIANCE F/(U)
1.	ELECTRIC ENERGY REVENUES	$614,725,050.00	$563,385,131.72	($51,339,918.28)
2.	INCOME FROM LEASED PROPERTY - NET			$0.00
3.	OTHER OPERATING REVENUE AND INCOME	$4,011,500.00	$4,957,104.01	$945,604.01
4.	TOTAL OPER REVENUES & PATRONAGE CAPITAL	$618,736,550.00	$568,342,235.73	($50,394,314.27)
5.	OPERATION EXPENSE-PRODUCTION-EXCL FUEL	$54,962,438.00	$48,054,670.68	$6,907,767.32
6.	OPERATION EXPENSE-PRODUCTION-FUEL	$240,841,163.00	$226,368,922.34	$14,472,240.66
7.	OPERATION EXPENSE-OTHER POWER SUPPLY	$126,165,163.00	$111,465,356.58	$14,699,806.42
8.	OPERATION EXPENSE-TRANSMISSION	$10,722,952.00	$10,118,765.89	$604,186.11
9.	OPERATION EXPENSE-RTO/ISO	$2,470,652.00	$2,262,434.76	$208,217.24
11.	OPERATION EXPENSE-CUSTOMER ACCOUNTS		$297,191.47	($297,191.47)
12.	CONSUMER SERVICE & INFORMATIONAL EXPENSE	$723,774.00	$886,167.75	($162,393.75)
13.	OPERATION EXPENSE-SALES	$1,101,600.00	$191,205.48	$910,394.52
14.	OPERATION EXPENSE-ADMINISTRATIVE & GENERAL	$25,925,640.00	$26,428,744.85	($503,104.85)
15.	TOTAL OPERATION EXPENSE	$462,913,382.00	$426,073,459.80	$36,839,922.20
16.	MAINTENANCE EXPENSE-PRODUCTION	$58,889,721.00	$41,169,861.77	$17,719,859.23
17.	MAINTENANCE EXPENSE-TRANSMISSION	$3,933,069.00	$4,607,997.64	($674,928.64)
18.	MAINTENANCE EXPENSE-RTO/ISO			$0.00
20.	MAINTENANCE EXPENSE-GENERAL PLANT	$101,538.00	$184,301.57	($82,763.57)
21.	TOTAL MAINTENANCE EXPENSE	$62,924,328.00	$45,962,160.98	$16,962,167.02
22.	DEPRECIATION & AMORTIZATION EXPENSE	$41,910,892.00	$41,090,390.70	$820,501.30
23.	TAXES	$885.00	$3,810.88	($2,925.88)
24.	INTEREST ON LONG-TERM DEBT	$44,647,132.00	$45,032,787.47	($385,655.47)
25.	INTEREST CHARGED TO CONSTRUCTION-CREDIT	($678,117.00)	($766,677.00)	$88,560.00
26.	OTHER INTEREST EXPENSE		$147,499.02	($147,499.02)
27.	ASSET RETIREMENT OBLIGATIONS			$0.00
28.	OTHER DEDUCTIONS	$415,812.00	$546,328.23	($130,516.23)
29.	TOTAL COST OF ELECTRIC SERVICE	$612,134,314.00	$558,089,760.08	$54,044,553.92
30.	OPERATING MARGINS	$6,602,236.00	$10,252,475.65	$3,650,239.65
31.	INTEREST INCOME	$61,860.00	$963,130.32	$901,270.32
32.	ALLOWANCE FOR FUNDS USED DURING CONST			$0.00
34.	OTHER NON-OPERATING INCOME - NET			$0.00
36.	OTHER CAPITAL CREDITS & PAT DIVIDENDS	$33,000.00	$61,485.01	$28,485.01
37.	EXTRAORDINARY ITEMS			
38.	NET PATRONAGE CAPITAL OR MARGINS	$6,697,096.00	$11,277,090.98	$4,579,994.98

BIG RIVERS ELECTRIC CORPORATION

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

Response to Commission Staff's Second Request for Information dated February 14, 2013

February 28, 2013

Item 12) ***Refer to the Richert Testimony at page 25, lines 18-22. Provide the basis for the statement that "G&Ts that borrow funds in the capital markets typically must earn margins and interest coverage ratios in excess of the minimum required MFIR stated in the credit agreements to obtain access to the financial markets, and to borrow capital at reasonable rates."***

Response) The statement is based on consultation with experts in the field, including Goldman Sachs and Orrick, Herrington & Sutcliffe, both of whom advise Big Rivers with regard to financing matters; and Dan Walker, who has thirty years of experience in utility finance, has direct experience in advising and managing the placement of cooperative debt, and with whom I consulted in the preparation of my testimony.

Witness) Billie J. Richert

BIG RIVERS ELECTRIC CORPORATION

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

Response to Commission Staff's Second Request for Information dated February 14, 2013

February 28, 2013

Item 13) ***Refer to the Richert Testimony at page 37, lines 2-11 and the Direct Testimony of Travis A. Siewert ("Siewert Testimony") at page 12, lines 8-14. After it filed its rate application, Big Rivers amended its application in Case No. 2012-00492. Explain what impact, if any, that amendment has on this rate application, included in any impact on Big Rivers' interest on long-term debt in the forecast period.***

Response) Amending Big Rivers' application in Case No. 2012-00492, if approved by the Commission, would lower Big Rivers' forecast period revenue requirement by approximately $4.4 million. The attached schedule details the decrease in Interest Expense on Long-Term Debt related to paying off the $58.8 million pollution control bonds with cash, the decrease in Interest Income, the decrease in the Amortization of Debt Issuance Costs, and the decrease in TIER requirement.

Witness) Billie J. Richert

Big Rivers Electric Corporation
Case No. 2012-00535

Attachment to Response for PSC 2-13

	Test Period	Test Period w/Amended Financing Case	Fav/(UnFav)
Interest Expense on Long-Term Debt	$ 46,983,291	$ 43,511,699	$ 3,471,592
Int. Income on Transition Reserve	$ 105,415	$ -	$ (105,415)
Int. Income on Temp. Investments	$ 97,916	$ 68,863	$ (29,053)
Amortization of Debt Issuance Costs	$ 505,012	$ 427,234	$ 77,778
Margins Required for 1.24 TIER	$ 11,381,405	$ 10,442,808	$ 938,597
			$ 4,353,499

BIG RIVERS ELECTRIC CORPORATION

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

Response to Commission Staff's Second Request for Information dated February 14, 2013

February 28, 2013

Item 14) ***Refer to the Richert Testimony at pages 37-38 where Big Rivers' reserve funds are discussed.***

a. ***Provide the current balances of the Economic Reserve fund and the Rural Economic Reserve Fund.***

b. ***Provide the projected date that each fund will be depleted.***

Response)

a. The balances of the Economic Reserve fund and the Rural Economic Reserve fund as of January 31, 2013 are $79,202,419.76 and $64,755,568.70, respectively.

b. It is estimated that the Economic Reserve fund will be depleted in 2015 and the Rural Economic Reserve fund will be depleted in 2017.

Witness) Billie J. Richert

BIG RIVERS ELECTRIC CORPORATION

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

Response to Commission Staff's Second Request for Information dated February 14, 2013

February 28, 2013

Item 15) ***Refer to Exhibit Richert-3, page 1 of 2. Has Big Rivers provided the Rural Utilities Service ("RUS") a response with a timeline for conducting major maintenance such as valve inspections and turbine generator inspections on a schedule consistent with prudent utility operations? If yes, provide that response. If no, when does Big Rivers anticipate submitting a response to RUS?***

Response) Big Rivers provided a response to the RUS in a letter from Mark Bailey dated February 6, 2013, that included a timeline for conducting the major maintenance that had been deferred. A copy of Mark Bailey's letter to the RUS is provided as an attachment to this response.

Witness) Robert W. Berry

Big Rivers
ELECTRIC CORPORATION

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

February 6, 2013

Mr. Chris Tuttle
Acting Deputy Assistant Administrator
Rural Utilities Service-Electric Program
United States Department of Agriculture
Room No. 5135-S
1400 Independence Avenue, S.W.
Stop 1510
Washington, D.C. 20250

Subject: Kentucky 62 - Big Rivers Electric Corporation

Dear Mr. Tuttle:

Please refer to your letter to me of December 27, 2012, approving the new depreciation rates proposed by Big Rivers Electric Corporation ("*Big Rivers*"). A copy of that letter is attached for your convenience. In that letter you conclude that certain Big Rivers' major maintenance and inspection practices, as described in the Executive Summary of the Burns & McDonnell Depreciation Study, are not acceptable to the Rural Utilities Service ("*RUS*"). You direct that Big Rivers "needs to resume their scheduled major inspections and maintenance per prudent utility operations promptly," and ask that Big Rivers inform you of its timeline for getting that matter resolved.

Big Rivers takes very seriously its obligations to its Members and the RUS to maintain its assets in accordance with prudent utility practice. The purposes of this letter are to furnish assurance that Big Rivers is properly inspecting and performing major maintenance on its assets, and to provide the maintenance schedule Big Rivers developed in May of 2012 to perform certain maintenance projects that had been deferred.

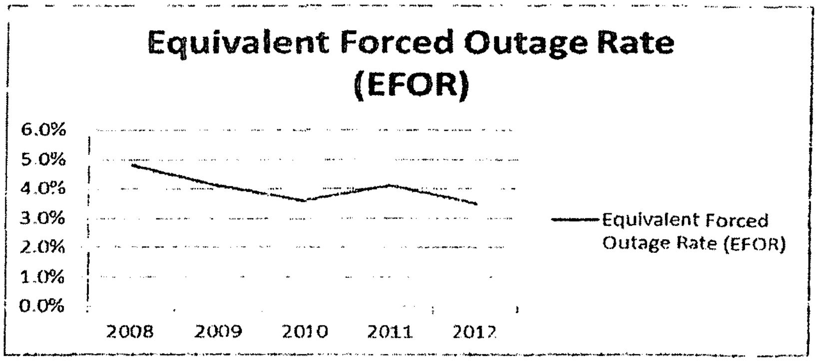
Big Rivers has selectively deferred certain inspection and maintenance activities since 2009 to assure that it will achieve its financial covenant performance requirements during a period of depressed wholesale power market prices and an unusually weak economy. But Big Rivers did not stop maintaining its assets. It selectively chose certain activities to complete, and others to defer, in order to continue to maintain a prudent level of maintenance while Big Rivers was adjusting to an economy in recession.

As a result of those efforts, Big Rivers' generating fleet has been very reliable since the closing of the Unwind Transaction in July 2009, and has consistently performed in the top quartile of its peer group in Equivalent Forced Outage Rate ("*EFOR*"), which we benchmark through Navigant's GKS system. The table below shows that Big Rivers' generating plant reliability has improved over the last five years, indicating the effectiveness of Big Rivers' maintenance program.

Big Rivers Generating Fleet	2008	2009	2010	2011	2012
Equivalent Forced Outage Rate (EFOR) *	4.8%	4.1%	3.6%	4.1%	3.5%

*EFOR (Lower is Better)

The following graph illustrates the downward trend (lower is better) in EFOR over the last five years.



Burns & McDonnell agrees with the prudency of Big Rivers' past maintenance practices and future maintenance plans in testimony filed with the Kentucky Public Service Commission on January 15, 2013, with Big Rivers' application for a general adjustment in rates. An excerpt of that testimony is attached for your information, and the full testimony is available under tab 71 of the copy of the application that Big Rivers sent to RUS on January 15, 2013.

The deferred maintenance schedule Big Rivers developed in May of 2012, and provided to Mr. James J. Murray by email dated December 12, 2012, affirms Big Rivers' intention to continue to perform major maintenance on its assets in a prudent and timely manner. That table is reproduced below, and remains unchanged from the version provided in December of 2012, and shows Big Rivers' timeline for performing the selected items of maintenance that were previously deferred. Big Rivers hopes this information allays RUS concerns. Please contact me if you have any further questions.

Deferred Maintenance Schedule

The following table provides a summary of the deferred outages and when they will be completed.

Plant	Original Outage Schedule	Deferred Maintenance To Be Completed
Coleman 1	February 2011	[redacted]
Coleman 2	March 2013	
Coleman 3	May 2012	
Green 1	March 2012	
Green 2	March 2011	
HMP&L 1	May 2011	
HMP&L 2	March 2012	
Wilson 1	September 2011	

* In August, 2013, coinciding with the Century Aluminum power sales contract termination, the current outage plans depict the Wilson unit temporarily idled until Big Rivers can secure replacement load. Big Rivers is still evaluating this strategy and the current plan is subject to change. If the Wilson plant is not idled the deferred maintenance will be completed in [redacted].

Sincerely yours,

Mark A. Bailey

Mark A. Bailey
President and CEO
Big Rivers Electric Corporation

Attachments
c: Power Supply Division

USDA Rural Development

United States Department of Agriculture
Rural Development

DEC 27 2012

Mr. Mark A. Bailey
President & Chief Executive Officer
Big Rivers Electric Corporation
P. O. Box 24
201 Third Street
Henderson, Kentucky 42419-0024

Dear Mr. Bailey:

This is in response to the letter dated November 20, 2012, from Ms. Billie J. Richert, to Mr. John Padalino, Acting Administrator of Rural Utilities Service (RUS), regarding Big Rivers Electric Corporation's (Big Rivers) request for RUS approval to revise the depreciation rates as recommended in the Comprehensive Depreciation Study Report (Depreciation Study) prepared for Big Rivers by Burns & McDonnell Engineering Company, Inc. dated November 2012.

In the Depreciation Study, Burn & McDonnell stated on Page ES-3 that since the Unwind Closing 2009, Big Rivers has not performed major maintenance such as valve inspections and turbine generator inspections on a schedule consistent with prudent utility operations. This is not acceptable to RUS and Big Rivers needs to resume their scheduled major inspections and maintenance per prudent utility operations promptly. **Please let us know of your timeline for getting this matter resolved.**

We find that the depreciation rate analysis that was performed based on the electric generation and transmission historical plant records of Big Rivers as of July 31, 2012 is acceptable; therefore, RUS hereby approves the new depreciation rates for the electric generation and transmission asset of Big Rivers included in above Depreciation Study as follows:

Account	Description	Existing Rates	Proposed Rates
Steam Production Plant			
340	Land	N/A	N/A
311	Structures	1.38%	1.38%
312	Boiler Plant	1.88%	2.02%
312 A-K	Boiler Plant - Environmental Compliance	2.28%	2.43%
312 L-P	Short-Life Production Plant - Environmental	20.22%	15.95%
312 V-Z	Short-Life Production Plant - Other	14.39%	25.38%

314	Turbine	1.91%	1.96%
315	Electrical Equipment	1.99%	2.03%
316	Miscellaneous Equipment	3.78%	4.04%
Combustion Turbine (CT) Production Plant			
341	CT - Structures	1.17%	1.06%
342	CT – Fuel Holders & Accessories	9.10%	9.92%
343	CT – Prime Movers	3.02%	3.02%
344	CT - Generators	0.50%	0.35%
345	CT – Access. Electrical Equipment	2.05%	2.93%
Transmission			
350	Land	N/A	N/A
352	Structures	1.90%	1.94%
353	Station Equipment	2.23%	2.29%
354	Towers	1.42%	1.36%
355	Poles	2.06%	2.03%
356	Lines	1.69%	1.81%

Depreciation rates for General Plant type facilities may be based on a borrower's experience and these rates do not require RUS approval.

Please let us know if we can be of further assistance.

Sincerely,

CHRIS TUTTLE
Acting Deputy Assistant Administrator
Rural Utilities Service-Electric Program

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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

DIRECT TESTIMONY

OF

TED J. KELLY
PRINCIPAL, BURNS & McDONNELL

ON BEHALF OF

BIG RIVERS ELECTRIC CORPORATION

FILED: January 15, 2013

5. A discussion of the operating and maintenance procedures for each production facility;
6. An analysis of external factors that may impact each facility's useful life;
7. An opinion, based on the study's findings, regarding the remaining life of each facility;
8. A discussion of the composition of the transmission system; and
9. An opinion, based on the study's findings, regarding remaining life of each substation.

Q. How is this used to determine depreciation rates?

A. The remaining life of each facility is provided in the Engineering Assessment and is a component that is considered in the calculation of depreciation rates. One important component of determining the remaining life of Big Rivers' facilities involves an evaluation of the maintenance activities performed by Big Rivers and the resultant operating condition of the facilities.

Q. Did RUS comment on Big Rivers maintenance practices mentioned in the Depreciation Study Report?

A. Yes. RUS indicated that Big Rivers needs to resume its scheduled major inspections and maintenance practices. RUS may have misunderstood what we were indicating in the report. As a result of prevailing resource constraints, Big Rivers selectively deferred some major maintenance while continuing routine maintenance. Inspections performed by Burns & McDonnell and a review of operating results over the last several years indicated no adverse conditions as a result of this short term deferral. Burns & McDonnell did review Big Rivers' plans, developed in May 2012, to reschedule the maintenance activities that are described by Bob Berry in his testimony. In light of the favorable operating results and assuming timely rescheduling of the deferred maintenance, in our opinion Big Rivers showed good judgment in the use of available resources and its facilities are being reasonably and prudently operated.

E. Facilities Review

Q. What facilities were reviewed?

A. A description of each of the facilities physically inspected and reviewed by Burns & McDonnell is provided in the Engineering Assessment of the 2012 Depreciation Study. (*See* Exhibit Kelly-1, Tables II-1 through II-8, pp. II-2 through II-6.)

i. Robert D. Green Plant

Q. Describe the Robert D. Green facility.

A. The Robert D. Green Plant ("Green Plant") is located on the Sebree site near Sebree, Kentucky, along with the Robert A. Reid Plant ("Reid Plant") and Henderson Municipal Power & Light Station Two ("HMP&L Station

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

Response to Commission Staff's Second Request for Information dated February 14, 2013

February 28, 2013

Item 16) ***Refer to the Direct Testimony of Robert W. Berry ("Berry Testimony") at pages 8-9, specifically, the discussion of Big Rivers' deferral of planned maintenance on its generating units. Refer also to Tab 38 of the application at page 2 of the year-to-date ("YTD") summary statement of operations for 2012.***

a. ***The testimony discusses the need to reduce maintenance costs in order to meet the requirements in Big Rivers' loan agreements, while the YTD summary shows that, through November 2012, actual net margins of $12 million were $10.7 million favorable when compared to budgeted net margins. Explain whether this means that, for 2012, Big Rivers' budgeted not to meet the requirements of its loan agreements.***
b. ***Explain whether the favorable budget variance of $10.7 million in net margins means that Big Rivers' deferrals of planned maintenance outages in 2012 exceeded what was necessary to meet the requirements of its loan agreements.***

Response)

a. No. Big Rivers' budgeted net margins for 2012 were $6.7 million with a 1.15 TIER. Big Rivers' budgeted net margins for the month of December 2012 were $5.4 million.

b. Big Rivers' actual net margins for 2012 were $11.3 million for the year [$4.6 million favorable to budget]. Big Rivers was able to achieve actual net margins of $11.3 million in 2012 only because it deferred $16.9 million in planned outage expense. If Big Rivers had performed the $16.9 million in planned outage expenses that were deferred, margins would have dropped below the minimum 1.10 margins for interest ratio ("MFIR") required by its debt covenants.

Because Big Rivers was trying to meet its year-end MFIR requirement, Big Rivers had to defer outages in advance of year end. The amount of planned outage expense Big Rivers deferred in 2012 ($16.9 million) was in part based on Big Rivers' experience in 2011. During 2011, margins for the 4th quarter were negative $3.3 million, driven by the mild temperatures and lower off-system market. As a result, in planning for the 4th quarter 2012, Big Rivers was conservative about anticipated margins. An unusually robust November 2012 was better than forecasted and drove margins for the 4th quarter positive $3.2 million. With the lead time on parts that must be ordered and professional labor that must be contracted, it was too late in the year to re-schedule the planned outages that had been deferred earlier in the year. So, it was only because of the $16.9 million in planned outage expense deferrals that Big Rivers ended the year $4.6 million favorable to budget. But without deferring planned outage expense, Big Rivers would not have met its minimum MFIR requirement.

Witness) Robert W. Berry

BIG RIVERS ELECTRIC CORPORATION

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

Response to the Commissions Second Request for Information dated February 14, 2013

February 28, 2013

Item 17) ***Refer to pages 16-17 of the Berry Testimony and Exhibit Berry 3, which shows that Big Rivers has budgeted $212,494,990 for capital construction during the 2013-2016 period. For each year from 2008 through 2012, provide a comparison of Big Rivers' budgeted capital construction expenditures and its actual capital construction expenditures.***

Response) Attached is the comparison of Big Rivers' budgeted capital construction expenditures and its actual capital construction expenditures for each year 2010 through 2012. The 2012 budgeted capital construction expenditures and actual capital construction expenditures variance is mainly due to the delay of CSAPR, MATS testing, outage deferrals on Coleman units 1 and 3, Green unit 2, scope reductions for Wilson's outage, and other items noted under variances in the attachment. In accordance with Big Rivers' records retention policy, budget actual and variance data is only retained for three years. Furthermore, Big Rivers does not have construction project budget actual and variance information that predates the closing of the Unwind Transaction on July 17, 2009.

Witness) Robert W. Berry

Big Rivers Electric Corporation
Case No. 2012-00535

Attachment to Response for PSC 2-17
Construction Projects
For the Years 2008-2012

Years	Annual Actual Cost		Annual Original Budget		Variance in Dollars	
2012	$	39,803,729	$	83,304,729	$	43,501,000
2011	$	36,621,844	$	40,935,996	$	4,314,152
2010	$	42,498,998	$	36,731,811	$	(5,767,187)
2009						
2008						

Note(s) -
1. - Total all projects for a given year.
2. - Information not available for years 2009 and prior. See response to this item for additional detail.
3. - Excludes City's Share

2012 Variance Explanations:
a) IT was favorable due to the cancellation of the Oracle Extensions project.
b) Coleman Station was favorable due to the C1 and C3 outage deferrals.
c) Wilson Station was favorable primarily due to outage scope reductions/deferrals.
d) Green Station was favorable due to the G2 outage deferral, as well as the reduction of the FGD project and cancellation of the Coal Sampler project.
e) Station-Two was favorable due to favorability of the H1 Burner Replacement project.
f) Transmission was favorable primarily due to deferral of the White Oak Substation project.
g) Other favorability mainly due to the delay of the MATS project, as well as cancellation of the CSAPR project.
h) Additionally, the PCI Analyzer Software project was cancelled.

BIG RIVERS ELECTRIC CORPORATION

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

Response to Commission Staff's Second Request for Information dated February 14, 2013

February 28, 2013

Item 18) *Refer to page 20 of the Berry Testimony concerning the fourth prong of Big Rivers' Load Concentration Mitigation Plan.*

a. Provide a detailed description of the economic development activities Big Rivers has undertaken and will undertake to mitigate the loss of the Smelter load.

b. Provide the Requests for Proposals ("RFPs") mentioned at lines 17- 18 and the status of the proposals Big Rivers submitted in response to the two RFPs.

c. Provide the dates on which Big Rivers provided its responses to the two utilities' requests for proposals.

d. Provide a detailed description of Big Rivers' preliminary discussions with other potential counterparties in an effort to market Big Rivers' excess power, including the status of such discussions and the steps that will be taken going forward.

Response)

a. Big Rivers is actively exploring options to find load replacement for the 850 MW currently being utilized by Century and Alcan. Big Rivers' strategy for replacing the additional Alcan load is currently unchanged from the original strategy envisioned. Big Rivers has been evaluating options to execute forward bilateral sales with counterparties, enter into wholesale power agreements, sell or lease assets, and/or gain access to developed capacity markets. Big Rivers is following a multi-pronged approach, with Big Rivers' members focusing on economic development opportunities and Big Rivers' Energy Services Department working to find wholesale marketing opportunities for the power.

Big Rivers' members (Kenergy Corp., Jackson Purchase Energy Corporation, and Meade County Rural Electric Cooperative Corporation (collectively, the "Members")) have been aggressively seeking 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. While Big Rivers' staff does not personally solicit new economic development prospects, we provide solid support to assist our Members in their efforts to attract new businesses to Western

Kentucky. Additionally, Big Rivers provides its three distribution Members with financial support to promote economic development initiatives within their cooperative communities. In 2012, Big Rivers supported its distribution Members with more than $100,000 in funding to encourage economic development efforts in Western Kentucky. Big Rivers believes these efforts can have a positive impact on influencing industrial and commercial load growth within our distribution Members' service territories.

b. The Requests for Proposal ("RFPs") are provided as attachments to this response. Big Rivers submitted a confidential proposal to provide firm capacity and energy in response to a RFP from Louisville Gas and Electric Company/Kentucky Utilities Company ("LGE/KU"). Big Rivers also submitted an unsolicited proposal to East Kentucky Power Cooperative ("EKPC") outside of EKPC's RFP process. EKPC's RFP process had deadlines that occurred prior to Big Rivers' receipt of Century's termination notice, thus Big Rivers was unable to participate in EKPC's RFP due to its lack of capacity, but it was able to submit an unsolicited proposal. Copies of the proposals are provided under a petition for confidential treatment as attachments to this response.

[redacted]

[redacted]

BIG RIVERS ELECTRIC CORPORATION

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

Response to Commission Staff's Second Request for Information
dated February 14, 2013

February 28, 2013

[redacted]

BIG RIVERS ELECTRIC CORPORATION

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

Response to Commission Staff's Second Request for Information dated February 14, 2013

February 28, 2013

[redacted]

[redacted]

BIG RIVERS ELECTRIC CORPORATION

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

Response to Commission Staff's Second Request for Information dated February 14, 2013

February 28, 2013

[redacted]

[redacted]

[redacted]

[redacted]

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

Response to Commission Staff's Second Request for Information dated February 14, 2013

February 28, 2013

[redacted]

Witness) Robert W. Berry

EAST KENTUCKY POWER COOPERATIVE

ALL SOURCE LONG-TERM REQUEST FOR PROPOSALS 2012

[JULY 5, 2012: TWO DATES REVISED; SEE ALSO THE FAQs ON WEBSITE FOR AMENDMENTS AND CLARIFICATIONS.]

RFP Issued:	**June 8, 2012**
Supporting, Required Forms Issued:	**June 15, 2012**
Notice of Intent to Submit Proposal Due:	**<u>July 10, 2012</u>**
Required Forms with Revisions Issued:	**<u>July 13, 2012</u>**
Proposal Submittal Deadline:	**August 30, 2012**
RFP website:	**www.ekpc-rfp2012.com**
RFP email:	**ekpc-rfp@brattle.com**

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1. INTRODUCTION

1.1 OVERVIEW

East Kentucky Power Cooperative (EKPC) is issuing this All Source Long-Term Request for Proposals 2012 (RFP) to obtain new resources through a solicitation of interest from utilities, power marketers, project owners and project developers who desire to place a bid or bids and meet the minimum qualifications as described herein (Bidders or Participants). EKPC has formally applied to the Kentucky Public Service Commission for approval to transfer functional control of its system into the PJM Interconnection (PJM) and will systematically assume for purposes of this RFP that EKPC is a full member of PJM.[1] Thus, all Bidders should assume that they will deliver the capacity and/or energy resources to EKPC within PJM and under the PJM rules and procedures.

Subject to this and other conditions discussed below, EKPC will consider the following resources in this RFP:

- New construction of conventional generation technologies and all fuel types to include turnkey ownership, joint ownership or other alternatives;
- Existing conventional generation (a share of a plant could be accepted);
- New and existing renewable generation (as discussed below).

Pursuant to policies of the Kentucky Public Service Commission (PSC) and consistent with EKPC's Integrated Resource Plan (IRP) filed with the PSC on April 20, 2012,[2] EKPC seeks to acquire up to 300 megawatts (MW) of new resources, with an on-line date of October 2015. EKPC will consider resources that come on-line up to two years later, on or about October 2017, but will have to evaluate any additional costs it may incur under this later on-line date. As discussed in the IRP, one reason for the need for new resources is the impact of the EPA's Mercury and Air Toxics Standards (MATS) regulation. EKPC will evaluate the costs of retrofitting its older coal plants to comply with MATS. EKPC intends to offer a self-build option for this RFP.[3] EKPC is not soliciting and will not accept capacity from PJM Demand Response resources. EKPC is developing its own demand side management resources.

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1 EKPC intends that during the full period of the contracts that come from this RFP it would be a signatory to the PJM OATT, the PJM Reliability Assurance Agreement, and the PJM Operating Agreement.

2 EKPC, *2012 Integrated Resource Plan*, with Technical Appendices, all Redacted, April 20, 2012.

3 EKPC has established a wall to ensure that no cost information will be shared between its Power Production business unit, which will prepare the self-build proposal, and its Power Supply business unit, which will be involved in evaluating the bids that are received. The Brattle Group, as Independent Procurement Manager, also

For new conventional and/or renewable generation facilities, Participants may submit Bids in two forms. The first form is a Power Purchase Agreement (PPA) with EKPC, which is contained in the set of Required, Supporting Forms (Required Forms), which will be put on the RFP website on June 15, 2012. This is discussed below in Section 5. EKPC will consider PPAs for capacity in the EKPC Locational Deliverability Area (LDA) in PJM. EKPC will consider PPAs for energy delivered to:

- the EKPC load zone in PJM;
- the AEP-Dayton (AD) Hub;
- other delivery points that are fully described such that EKPC can determine the equivalent costs for delivery in comparing alternatives.

A PPA for bundled energy and capacity would need to specify both the energy delivery point and the LDA. EKPC would consider a bundled bid with the energy delivered to the AEP-Dayton Hub and the capacity delivered to the PJM LDA for AEP, and would evaluate any incremental costs or benefits from that arrangement. EKPC will consider energy and capacity from new or existing renewable generation resources.

One of the Required Forms is a signed draft PPA, which at the Bidder's discretion will contain terms, such as pricing terms, that are binding for 60 days from August 30, 2012. This signed form must be submitted for each PPA Bid. The conditions for the PPA Bids are discussed below in Section 2.3.4. Again, all Required Forms with their terms will be posted to the "ekpc-rfp2012" website on Friday, June 15, 2012. The final revisions to the Forms will be posted to the website by Tuesday, July 10, 2012.

The second form of the Bid is Facility Ownership by EKPC. For Facility Ownership, the sale would be conducted pursuant to a Purchase and Sale Agreement (PSA) and related documentation, which is found in Required Forms. This is the contract form under which a Participant would sell full or part ownership in an existing plant or would develop and cause to be constructed a fully permitted, operational generation facility, which would be sold in entirety or in part to EKPC at project completion. EKPC solicits both full and partial ownership shares, as long as the MWs of the project are within the minimum and maximum bounds for MW discussed below and other conditions are met. The Required Forms for Facility Ownership Bids would not need to be executable, but the conditions as discussed in the Required Forms would have to be met by any Bidder, or a Facility Ownership Bid may not be deemed acceptable to EKPC.

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will have no contact with the Power Production business unit staff that are involved in the preparation of a self-build proposal.

EKPC has three sites in its service territory suitable for locating a gas-fired combined cycle combustion turbine facility (CCGT) or a gas-fired single cycle combustion turbine facility. A Participant could propose to build at any of these sites under the Facility Ownership and PSA arrangement. EKPC is not accepting a Bid for a PPA at any of these sites. For these three sites, EKPC will be responsible for building the fuel pipeline from the nearest natural gas pipeline interconnection to the input point of the generation plant. The three sites have different expected costs for this fuel pipeline connection, which the Bidders may wish to consider. EKPC will also secure the air and water permits. Additional information and the conditions for the use of the EKPC sites are described in a Required Form on development and siting status. EKPC may submit self-build proposals at one or more of its sites.

Additional general conditions are that Contracts for new resources should have a minimum of 50 MW for any conventional resource and 5 MW for any renewable resource, as further specified in Section 2.3.2 below. This is a long-term procurement, so the length of any PPA should be at least five years and can be longer at Bidder's discretion. EKPC's 2012 IRP showed a preference for dispatchable and operationally flexible resources, but EKPC will evaluate any reasonable and fully described resource that a Bidder offers.

East Kentucky Power Cooperative, Inc. is committed to environmental stewardship while safely providing affordable, reliable power to its members. Therefore, EKPC will also consider proposals for energy and capacity from renewable generation resources. The renewable resources' bids must be a minimum of 5 MW (single resource or an aggregate in one Bid that is greater than or equal to 5 MW). The duration of the renewable energy resource contract(s) should range from a minimum of 5 years to the life of the facility. The capacity and/or energy must be deliverable to EKPC's Delivery Points as described herein. Renewable energy resources may include, but are not limited to:

- Wind
- Biomass
- Solar (electric or thermal)
- Hydro
- Geothermal
- Recycled energy (waste heat, etc.)

This RFP is open to those parties who currently own, propose to develop, or have rights to a renewable energy generating facility 5 MW or larger. Preference will be given to renewable projects that are in the state of Kentucky. Bidders may submit multiple proposals to fulfill the resource request. The proposal must be based upon a proven technology.

EKPC will retain all environmental attributes associated with Bidder's proposed bid energy, including but not limited to renewable energy credits, green tags, greenhouse gas or carbon credits, and any other emissions attributes. EKPC has engaged the services of The Brattle Group to act as an independent procurement manager and perform a comparative analysis and evaluation of proposals received under this solicitation. EKPC reserves the right to retain any other independent consulting service that it may deem necessary or advisable. The final decisions with regard to acceptance or rejection of any or all proposals are specifically reserved to EKPC, subject to the approval of the Kentucky PSC.

1.2 SCHEDULE

The schedule for this RFP process is set forth in Table 1. This schedule is subject to adjustment and any changes will be posted immediately on the website.

Table 1: Major Milestones for the RFP

No.	Major Milestones for the RFP	Dates
1	RFP document and Form 1 issue date	Friday, 6/8/2012
2	RFP Website live	Friday, 6/8/2012
3	Date to register at the Website to receive all further information with respect to the RFP. Potential bidders can continue to register up to Tuesday, 7/3/2012.	Wednesday, 6/13/2012
4	On the website, all Required Forms for a Bid will be posted, which will explain the information requirements for the Bids. An objective is to allow Bidders to fully explain their Bids, while systematically collecting as much information as possible in machine-readable format. Suggestions for improvements will be accepted by email through Tuesday, 7/3/2012, and the final Forms distributed on Tuesday, 7/10/2012	Friday, 6/15/2012
5	Webinar to answer questions of prospective bidders	Wednesday, 6/27/2012
6	**Due date for Notice of Intent to Submit Proposal (Reset on July 2, 2012)**	**Tuesday, 7/10/2012**
7	**Final versions of Bidder Response Forms, including Excel Forms 10 - 13 that should include binding values for 60 days, except as explicitly indicated by bidder, as discussed in Draft Forms 10 - 13.**	**Friday, 7/13/2012**
8	Proposals due in electronic form	Thursday, 8/30/2012
9	Proposals due with wet signed orginal in hardcopy	Wednesday, 9/5/2012
10	Date up to which the executable PPA Bids must be good, which is 60 days after the PPA Bids are submitted. EKPC may exercise the right to execute any such PPA Bid.	Sunday, 10/28/2012
11	Select Short Listed proposals, assuming that the RFP is going to continue.	Thursday, 11/1/2012
12	Execute Project Agreements, if not executed earlier.	1/1 - 1/15/2013

1.3 DISCLAIMER FOR REJECTING BIDS AND/OR TERMINATING THIS RFP

This RFP does not constitute an offer to buy and creates no obligation to execute any Agreement or to enter into a transaction under an Agreement as a consequence of the RFP. EKPC shall retain the right at any time, in its sole discretion, to reject any Bid on the grounds that it does not conform to the terms and conditions of this RFP and reserves the right to request information at any time during the solicitation process. EKPC also retains the discretion, in its sole judgment, to: (a) reject any Bid on the basis that it does not provide sufficient ratepayer benefit or that it would impose conditions that EKPC determines are impractical or inappropriate; (b) implement the appropriate criteria for the evaluation and selection of Bids; (c) negotiate with any Participant to maximize ratepayer benefits; (d) modify this RFP as it deems appropriate to implement the RFP and to comply with applicable law or other direction provided by the PSC; and (e) terminate the RFP should the PSC not authorize EKPC to execute Agreements of the type sought through this RFP. In addition, EKPC reserves the right to either suspend or terminate this RFP at any time for any reason whatsoever. EKPC will not be liable in any way, by reason of such withdrawal, rejection, suspension, termination or any other action described in this paragraph to any Participant, whether submitting a Bid or not.

1.4 CONTACT INFORMATION

The Brattle Group (Brattle) is serving as the Independent Procurement Manager (IPM) for this RFP process. Proposals in response to this RFP are due at the IPM's offices no later than 4PM Pacific Daylight Time (PDT) on Thursday, August 30, 2012.

Proposals are to be submitted by mail, e-mail, fax, or hand delivery to the IPM. Faxed or e-mailed proposals must be followed up by a signed original that is delivered by mail or overnight courier no later than 4PM PDT on September 5, 2012.

All correspondence should be directed to the IPM at the following address:

EKPC All Source RFP c/o The Brattle Group
201 Mission St., Suite 2800
San Francisco, CA 94105
Phone: 415.217.1000
Fax: 415.217.1099
E-mail: ekpc-rfp@brattle.com
Web Site: www.ekpc-rfp2012.com

2. EKPC SITUATION AND THE RFP GOALS

2.1 HISTORY

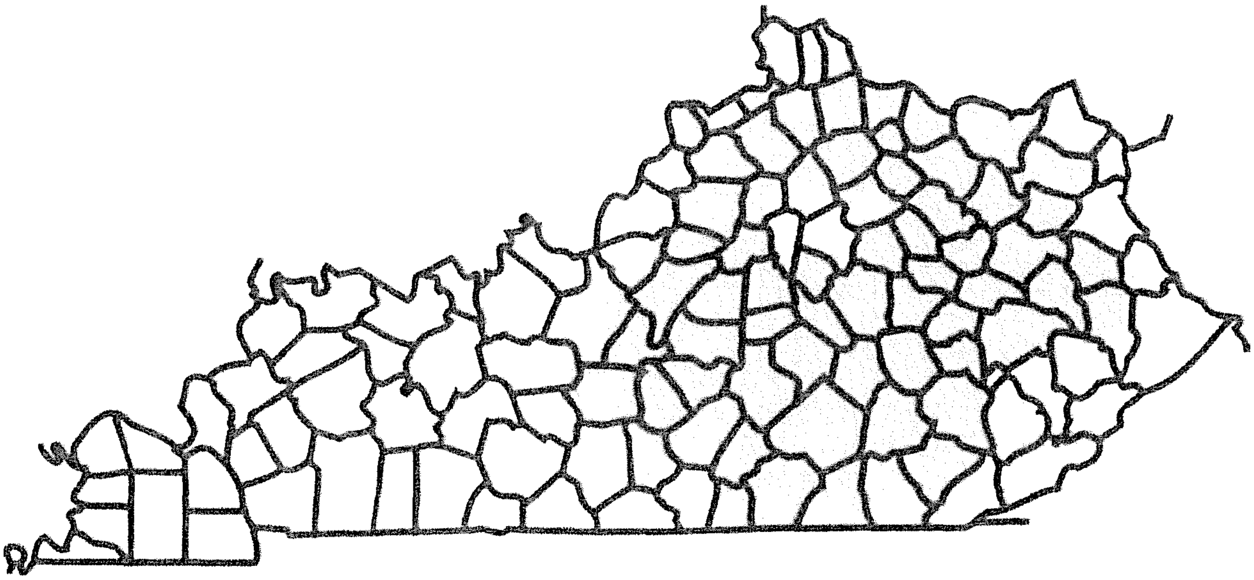
East Kentucky Power Cooperative, Inc. (EKPC) is headquartered in Winchester, KY and provides electric power and energy to 16 member distribution cooperatives serving approximately 511,000 meters in 87 Kentucky counties. EKPC is a member of the National Renewable Cooperative Organization. EKPC's existing resource portfolio consists of approximately 2,500 MW of coal and gas generating capacity, 15 MW of Landfill Gas generation, 170 MW of South East Power Administration (SEPA) hydro power, and various power purchase contracts. EKPC has applied for membership in PJM, and expects to be a member during the entire period of any contracts that result from this RFP. In addition to being a member of PJM, EKPC expects to maintain interconnections with the following other utilities/markets:

- KU/LG&E/PPL
- Tennessee Valley Authority (TVA)

Pursuant to policies of the Kentucky Public Service Commission (PSC) and consistent with EKPC's Integrated Resource Plan (IRP) filed with the PSC on April 20, 2012,[4] EKPC seeks to acquire up to 300 megawatts (MW) of new resources, with on-line date on October 2015. EKPC will consider resources that come on-line up to two years later, on or about October 2017, but must evaluate any additional costs it may incur under this later on-line date. As discussed in the IRP, one reason for the need for new resources is the impact of the U.S. EPA's MATS policy. EKPC will evaluate the costs of retrofitting its older coal plants to comply with MATS. EKPC intends to offer a self-build option for this RFP. EKPC is not soliciting and will not accept bids for capacity from PJM Demand Response resources. EKPC has its own demand side management resources that it is developing.

[4] EKPC, *2012 Integrated Resource Plan*, with Technical Appendices, all Redacted, April 20, 2012.

2.2 SYSTEM MAP



The above map shows the territory of EKPC and its member systems.

2.3 RFP GOALS

2.3.1 EKPC Resource Needs

EKPC submitted its Integrated Resource Plan (IRP) to the Kentucky Public Service Commission on April 20, 2012. Based on its IRP, EKPC projects it will need approximately 300 MWs of capacity by October 2015. As mentioned previously, EKPC will consider resources that come on-line up to two years later, that is, on or about October 2017, but must consider any additional costs it may incur under a later on-line date.

To meet this projected need, EKPC is seeking Bids from resources that meet the specifications set forth in Section 4 "Submission of Proposals and Eligibility Requirements." Attractive bids will be those that allow EKPC to produce energy and capacity products compatible with EKPC's requirements, and contribute to the other criteria specified in Section 6 "Proposal Evaluations."

In this solicitation, EKPC is willing to consider a wide range of intermediate and long-term resources that meet all or part of its requirements. EKPC will evaluate the benefits and costs of Bids in light of its existing portfolio of supply and demand-side resources.

EKPC must fully understand operational limitations of each Bid due to environmental constraints, such as air quality limitations. If applicable, Participants should specify all operational constraints the resource will be required to meet, such as those needed to comply with local Air Board requirements as well as other permitting requirements.

In addition, EKPC intends to bid any resources selected as a result of this RFP into the PJM market. EKPC will rely on any selected Bidder's attestations as to expected commercial operations date (COD), delivery date, or other time sensitive information contained in the response. As such, it is expected that any negotiated agreement will contain terms including but not limited to liquidated damages and/or replacement capacity costs at the prevailing market price for capacity at the time of expected delivery and until such time as performance is satisfied under the terms of said agreement.

2.3.2 Resources

EKPC will consider proposals (1) to enter into power purchase agreements and (2) to purchase new or existing generation resources (full or partial). Also, EKPC will consider Bids from conventional and renewable generation resources. EKPC has a preference for physical resources or PPAs that are based on physical resources. EKPC is not willing to enter into purely financial contracts to satisfy this RFP.

Conventional Generation

For purposes of this solicitation, the term "conventional generation" includes combined cycle and simple cycle (combustion turbine) technologies fueled by natural gas or bio-fuels. It also includes existing coal, nuclear and hydro facilities. Minimum Bid size is 50 MW from each facility.

Renewable Resources

EKPC will consider energy and capacity from new or existing renewable generation resources, including facilities burning biodiesel, digester gas, landfill gas or municipal solid waste, fuel cells using renewable fuels, geothermal facilities, ocean wave, ocean thermal and tidal current facilities, solar photovoltaic and solar thermal facilities, small hydroelectric (30 megawatts or less) facilities and wind generators. The minimum Bid size is 5 MW from each facility.

2.3.3 Facility Ownership: Generation Characteristics

Each facility will be operated to provide products as needed to conform to the requirements of PJM. For some resources, this is expected to include multiple daily starts and stops, rapid turndown of and ramp up within the unit's capabilities and full compliance with environmental permit conditions. This is to be satisfied by fully and accurately completing the Required Forms.

Load Following Generation

Bids to develop and sell a shaping or load following facility to EKPC will be expected to have the Generation Operating Characteristics described in a Required Form on combined cycle plants. The ability to meet these characteristics will be given additional weight in the evaluation process. Bids other than natural gas-fired technologies should respond to the appendices in a full and complete manner indicating where information is not applicable and provide additional information where appropriate in order to allow EKPC to fully evaluate its bids. Bids must meet all federal and state laws and be able to secure all permits.

Peaking Generation

Bids to develop and sell a peaking facility to EKPC will be expected to have the Generation Operating Characteristics described in a Required Form on simple cycle combustion turbines. The ability to meet these characteristics will be given significant weight in the evaluation process. Bids other than gas-fired technologies should respond to the appendices in a full and complete manner indicating where information is not applicable and provide additional information where appropriate in order to allow EKPC to fully evaluate its Bid. Bids must meet all federal and state laws and be able to secure all permits.

Baseload Generation

Bids to develop and sell baseload generation to EKPC will be expected to have the Generation Operating Characteristics described in a Required Form. Bids must meet all federal and state laws and be able to secure all permits.

2.3.4 Contract Options

All PPA Bids should include a draft PPA as part of the bid. Unless clearly set forth in the draft PPA to the contrary, the terms of the PPA shall be binding upon the Participant for 60 days from the date of submission, August 30, 2012,which is until October 28, 2012. Any section(s) or terms of the draft PPA which the Participant intends to be non-binding on the Participant (and subject to further negotiation) shall be clearly designated in the draft PPA. At the end of that period on October 29, 2012, EKPC may ask the Bidder to refresh the Bid for another 60 days, and the Bidder can respond accordingly, including any updates as to the binding nature of the terms of the draft PPA, so as to continue to be considered in the Short List negotiation of this RFP. Failure of a Bidder to provide a draft Purchase Power Agreement as set forth herein may result in disqualification of the Participant's Bid.

All Facility Ownership/PSA Bids must fully meet the conditions that are imposed on that kind of bid. These conditions will be stated in the Forms on Facility Ownership/PSA Bids that will be issued on June

15, 2012. EKPC wants to be certain that Facility Ownership Bidders planning to use an EKPC site are providing accurate and complete cost numbers on which they are prepared to execute. However, EKPC recognizes that building on one of its sites is likely to require additional negotiations, so EKPC is not expecting a fully-executable Facility Ownership Bid. Failure of a Participant to fill the details of the Required Forms for Facility Ownership/PSA option may result in disqualification of the Participant's Bid.

PPAs

EKPC is seeking PPA Bids for new and existing renewables and new and existing conventional generation technologies, including technologies capable of running on multiple fuels. The Required Forms will contain all forms for the PPA Bids. EKPC will provide the Required Forms on the website on June 15, 2012 and update certain of the Required Forms by July 10, 2012. As discussed above, each PPA Bid at the Bidder's discretion can have terms, such as price terms, that are binding for 60 days from its submission on August 30, 2012, which is until October 28, 2012.

For PPA Bids from natural gas-fired facilities, EKPC's preferred contract structure is a fuel conversion (tolling) structure. The documentation requested in the Required Forms will be generally structured to accommodate gas-fired units and a fuel conversion agreement. Participants offering a PPA other than a fuel conversion agreement for a gas-fired facility should adapt the documentation by selecting or deleting the optional elements as appropriate or making such other adjustments as necessary and appropriate for the technology and fuel-type offered. See the Required Forms.

Regardless of the contract structure offered, Participants are requested to specify contract quantities, fixed O&M costs, variable O&M costs, contract heat rate(s) (where applicable), and other parameters to aid EKPC in comparing Bids, which will be requested on the Required Forms.

Participants can submit fixed-price PPA Bids. Participants can also submit PPA Bids that use indexed pricing, as described below.

- PPAs must meet all of PJM requirements for Capacity transactions, as contained in the PJM Business Manuals,
- PPA must meet all of the PJM requirements for Energy transaction, as contained in the PJM Business Manuals,
- Variable O&M, Fixed O&M, Variable Energy and Fired Hour Charge: A Participant shall indicate in its Bid an initial price for each of these components. If the Participant elects to use indexed pricing, the Participant should fully describe the indexation approach by filling out the appropriate Required Forms, which will be sent out on June 15, 2012,

- Capacity Payment Rate: A Participant shall indicate in its Bid an initial price for capacity. If the Participant elects to use indexed pricing, the Participant should fully describe the indexation approach by filling out the appropriate Required Forms, which will be sent out on June 15, 2012.

Purchase and Sale Agreements (PSAs)

EKPC is seeking PSA Bids for Facility Ownership of new conventional generation technologies, including technologies capable of running on multiple fuels, whereby the Participant would design, develop, permit, construct and commission the facility. EKPC has three existing sites for such a facility, as discussed in the Required Forms. EKPC would take ownership of the facility once it is constructed, tested and accepted. Bids must include milestone guarantees and performance guarantees for the completed facility. Participants must completely fill out, but will not have to provide any executable Required Forms for a PSA.

Participants can submit fixed-price PSA Bids, as will be described in the Required Forms.

The PSA term sheet will be provided in the Required Forms. Generation characteristics that EKPC is seeking are described in Section 2.3.3 "Facility Ownership." EKPC plans to update the Required Form for the PSA Bids by July 10, 2012.

Purchase Price: A Participant shall indicate in its Bid a purchase price, as of the date the Agreement is executed by EKPC, for a Project offered in a PSA Bid.

The Delivery Points are:

- The EKPC load zone for energy and EKPC LDA for capacity,
- The AEP-Dayton (AD) Hub for energy and PJM LDA for AEP for capacity,
- other delivery points that are fully described such that EKPC can determine the equivalent costs for delivery in comparing alternatives.

As part of an individual Bid, a Participant may submit Bid variations, with each Bid variation indexing certain components. For example a Participant offering a PPA could offer one variation with a fixed capacity price and another variation may index the capacity price, while both Bid variations index the other pricing components. This information should be provided in the Required Forms.

3. TRANSMISSION AND DELIVERY INFORMATION

3.1. PJM MEMBERSHIP TO BE ASSUMED

EKPC considers transmission reliability to be of utmost importance, and the Bidder should specify what arrangements it intends to make to deliver the power reliably. EKPC has formally applied to the Kentucky Public Service Commission to join and is expecting to be a full member of PJM during the term of any contract resulting from this RFP. If the Bidder is also a member of PJM, then the transmission arrangements will be governed by the PJM protocols. If the Bidder is outside of PJM, the Bidder will have to explain the expected cost and reliability of transmission to the PJM system and to the EKPC Delivery Points.

Any modifications or additions to EKPC's system, including interconnection, transmission, or communications facilities, required by a Bidder for power delivery to EKPC's system, shall be subject to review and approval by EKPC. Expenses relating to any such modifications or additions will be included or inferred by EKPC in the price evaluation of the Bidder's proposal.

4. SUBMISSION OF PROPOSALS AND ELIGIBILITY REQUIREMENTS

4.1. OVERVIEW OF PROCESS

The bid process will include the events as indicated on the schedule in Section 1.2. June 8, 2012 is the release of the RFP and the opening of the website. On July 3, 2012, interested Bidders will be requested to submit a Notice of Intent to Submit Proposal form. Proposals will due August 30, 2012. The proposals will be screened and non-conforming offers will be rejected. Bidders for a short list can expect to be notified on or about November 1, 2012. There will begin negotiations of final offers. Final negotiation and the signing of offers will occur if the negotiations are successful.

4.2. NOTICE OF INTENT TO SUBMIT PROPOSAL

A Notice of Intent to Submit a Proposal is requested from all prospective Bidders. This notice includes a Confidentiality Agreement. This will be Form 1 in the Required Forms and should be returned to the IPM Official Contact as listed in Section 1.4. This form is due to the IPM at The Brattle Group offices by no later than by 4PM PDT on July 3, 2012. In addition to postal mail, fax, and email are sufficient as means to return the Notice of Intent to Submit Proposal. Potential Bidders should make their best effort to provide accurate information about their planned Proposal; however, Bidders will not be bound by the information provided in the completed Form 1, Notice of Intent to Submit Proposal.

4.3. DEADLINE AND METHOD PROPOSAL SUBMISSION

Proposals are due to the IPM no later than 4PM PDT on August 30, 2012. Proposals are to be submitted by mail, e-mail, fax, or hand delivery. Faxed or e-mailed proposals must be followed up by mail with a signed original which must be received no later than 4PM PDT on September 5, 2012. All correspondence should be directed to the IPM, as indicated in Section 1.4 of this RFP document.

5. PROPOSAL CONTENT

A proposal should contain responses on all of the Required Forms, which will be provided in the website on June 15, 2012. The Forms will encourage Bidders to provide additional information or other supporting documentation to provide a complete description of the proposal. The Brattle Group will receive suggestions on how the Forms can be enhanced to allow more complete descriptions of the Bids and, at the discretion of EKPC, use those suggestions to finalize the Forms on July 10, 2012. EKPC retains the right to combine any Bid with any other Bid to determine a mix of resources that will provide a total economical and reliable resource package.

The Required Forms will deal with the following issues:

- Conditions on the Firmness of the Offers
- General Project Characteristics
- Development Status and Site Description, which describes three EKPC sites that will be offered for Facility Ownership / Purchase and Sale Agreement
- Capacity and Energy Profile
- Technical Description and Data by Resource Type
- Description of Pricing Methodology
- Pricing Information
- Transmission and Interconnection
- Financing and Credit Arrangements
- References
- Project Team
- EEI Master Purchase Power and Sale Agreement
- Power Purchase Agreement for the RFP, and the relationship to the EEI Master Agreement
- Purchase and Sales Agreement for the Facility Ownership

EKPC will provide the Required Forms on the website on June 15, 2012. On July 10, 2012, EKPC will provide final updates to the Required Forms.

6. PROPOSAL EVALUATION

6.1. SCREENING

All proposals will be evaluated for completeness and technical viability as a part of initial screening. Non-competitive bids will be eliminated based on this preliminary analysis.

6.2. EVALUATION

EKPC and The Brattle Group will specifically take into account the price, type and location of project, reliability, dispatchability, transmission availability, financial stability, and any other factor which relates to the suitability of the proposed project for meeting EKPC's power supply needs. EKPC reserves the right to consider any and all aspects of any bid in its evaluation as well.

6.3 FINANCIAL STABILITY AND PERFORMANCE GUARANTEES

Financial stability of the Bidder, demonstrated ability to fulfill its contractual obligations and historical project and contract performance are of utmost importance to EKPC and will be an integral part of EKPC's evaluation process. EKPC requires secure and reliable physical delivery of the capacity and associated energy corresponding to all PPAs. A performance bond, or some other form of security acceptable to EKPC, will be required to ensure the consistency and reliability of the physical delivery of energy and capacity.

For equipment and/or erection contracts, successful Bidders shall secure, upon contract award, performance bond(s) to provide financial assurance that the project will meet schedule and proposed performance targets. EKPC reserves the right to determine, in its sole judgment, the sufficiency of any performance bond (or other form of security) proposed by Bidder.

The Bidder should discuss in detail the type and amount of proposed credit enhancements or other means proposed to guarantee performance under any contract that might result from this RFP. This discussion should identify the entity providing such performance security and provide all relevant terms of such security mechanism. Bidder must provide audited financial statements from the previous three years in order to demonstrate its financial viability. Such financial information shall also be provided for any entity which would provide a performance bond or other form of security.

Bidders proposing "greenfield" sites or new generation at one of EKPC's 3 suggested locations must provide a description of the Bidders' ability to execute such projects as demonstrated by previously applicable experience and examples of operating facilities caused to be designed, permitted, constructed, tested and achieving successful commercial operation within a time frame typical for such type of project. Other means of satisfying EKPC's concerns regarding the Bidders expertise and experience may be considered but will be at EKPC's sole discretion in determining the Bidders qualifications and acceptance or rejection.

Failure by Bidders to not address the requirements herein may result in rejection of the Bid(s).

6.4. CONFIDENTIALITY

Form 1 Notice of Intent to Submit a Proposal is part of the Required Forms and will contain a Confidentiality Agreement. The Bidder must return a signed Required Form including the Confidentiality Agreement on July 3, 2012, as discussed above Section 4.2.

EKPC will not disclose any information contained in the Bidder's proposal that is marked "Confidential" to another party unless such disclosures are required by law or by a court or governmental or regulatory agency having appropriate jurisdiction. As a regulated utility and electric cooperative, EKPC may be required to release proposal information to various government agencies and/or others as part of a regulatory review or legal proceeding. EKPC also reserves the right to disclose proposals to any EKPC consultant(s) for the purpose of assisting in evaluating proposals. In the event EKPC is required to submit copies of proposals to the Kentucky Public Service Commission (PSC) or other governmental or regulatory agency, EKPC will attempt to file such information labeled as "Confidential" on a confidential basis. Designating specific information as confidential, rather than the entire proposal, may facilitate such efforts. However, EKPC cannot guarantee that such information will be deemed confidential by the agency or court the information is filed with.

By submitting a proposal to EKPC under this RFP, Bidder certifies that it has not divulged, discussed, or compared its proposal with other bidders and has not colluded whatsoever with any other bidder or parties with respect to this proposal.

6.5. ACCEPTANCE OF PROPOSALS

EKPC reserves the right, without qualification, to select or reject any or all proposals and to waive any formality, technicality, requirement, or irregularity in the proposals received. EKPC also reserves the right to request further information, as necessary, to complete its evaluation of the proposals received, and to negotiate with Bidders selected for the short list, prior to any selection of any winning proposals. Bidders who submit proposals do so without recourse against EKPC for either rejection by EKPC or failure to execute an agreement for purchase of capacity and/or energy for any reason. EKPC will not reimburse any Bidders for any cost incurred in the preparation or submission of a proposal and/or any subsequent negotiations regarding a proposal. All hard copies of proposals once submitted will become the property of EKPC.

6.6. SHORT LIST DEVELOPMENT

EKPC will develop a short list of potential proposals based on the benefit to EKPC's members. EKPC will then refine its analyses and develop its final decision. Acceptance of final bids will most likely be subject to approval by the Kentucky Public Service Commission, permitting agencies and potentially the Rural Utilities Service or other lenders. All respondents to the PPA Bid options must keep the terms of their bids firm and in effect until October 28, 2012, after which the Bidders can refresh the Bids if EKPC wants to put the Bidder on the Short List.

PPL companies

LG&E and KU Energy LLC
Energy Services
220 West Main Street
Louisville, KY 40202
www.lge-ku.com

Charles A. Freibert, Jr.
Director Marketing
T 502-6273673
charlie.freibert@lge-ku.com

ACES Power Marketing
Attn: Director Development, Marketing and Trading
4140 West 99th Street
C/O ACES Power Marketing -
Carmel IN 46032-7731

September 7, 2012

Subject: Request for Proposals to Sell Capacity and Energy (RFP)

Dear Colleague in Development, Marketing and Trading of Electrical Power,

Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (jointly the "Companies") are evaluating alternatives means to provide least-cost firm generating capacity and energy to our customers in the future. To this end, the Companies are requesting proposals from parties wishing to sell capacity and energy that will qualify as a Designated Network Resource (DNR) either as an owned asset by the Companies or a Power Purchase Agreement with the Companies. The Companies will consider offers that are reliable, feasible and represent the least-cost means of meeting our customers' capacity and energy needs, including cost for transmission service, transmission upgrades and voltage support. The Seller should make its proposal as comprehensive as possible so that the Companies may make a definitive and final evaluation of the proposal's benefits to its customers without further contact with the Seller. However, the Companies reserve the right to request additional information. Any failures to supply the information requested will be taken into consideration relative to the Companies' internal evaluation of cost, risk, and value.

This inquiry is not a commitment to purchase and shall not bind the Companies or any subsidiaries of LG&E and KU Energy LLC in any manner. The Companies in their sole discretion will determine which Respondent(s), if any, it wishes to engage in negotiations that may lead to a binding contract. The Companies shall not be liable for any expenses Respondents incur in connection with preparation of a response to this RFP. The Companies will not reimburse Respondents for their expenses under any circumstances, regardless of whether the RFP process proceeds to a successful conclusion or is abandoned by the Companies at their sole discretion.

1. **Background** - This RFP is being issued in order to evaluate alternative means to provide least-cost firm generating capacity and energy to our customers in the future while meeting all laws and regulations. All alternatives (including any of the Companies' self-build options) will be evaluated in the context of meeting customers' load in a least-cost manner. If the Companies determine that a proposal maybe in the best interest of the Companies' customers, the Companies will enter into negotiations which may lead to the execution of definitive agreements. The Companies will consider all applicable factors including, but not limited to, the following to determine the least-cost proposal(s): (i) the terms of the purchased power proposal or facility or asset sale; (ii) Seller's creditworthiness; (iii) if applicable, the development status of Seller's generation facility including, but not limited to, site chosen, permitting, and transmission; or the operating history of Seller's generation facility; (iv) the degree of risk as to the availability of the power in the timeframe required; (v) the anticipated reliability of the power, particularly at times of winter and summer peak; and (vi) all other factors such as the cost of interconnection or transmission that may affect the Companies or their customers. The Companies are committed to implementing the best overall long-term solution for their customers.

2. **Requirements** - The Companies are interested in Power Purchase Agreements ("PPA"), Tolling Agreements ("TA") or Build Own Transfer Agreements ("BOT"), or alternative power supplies (combined "Supply Agreements") for minimum quantities of 1 MW up to a total of 700 MW of firm summer and winter capacity and associated energy per facility or offer. The power being proposed must be generated from a defined source, a specific unit(s) or system that will qualify as a DNR and supply capacity/energy during the peak demand of the Companies' customers (typical Midwest seasonal load characteristics). The delivery of capacity and energy should begin no earlier than January 1, 2015, and later start dates will be considered. The Companies are interested in both short term (1 to 5 years) and long term (10 to 20 years) proposals. The Companies may procure more or less than 700 MW and may aggregate capacity and energy from multiple Sellers to meet its needs. A Seller offering power from a resource connected directly to the Companies' transmission system must conform to the Companies' Open Access Transmission Tariff (OATT) and must obtain in a timely manner an Interconnection Agreement for the facility.

3. **Key Terms and Conditions** - The Seller's proposal should include the proposed terms and conditions, which should include, where applicable to the Seller's proposal, among other things:

   3.1. Seller will guarantee all pricing and terms that affect pricing such as but not limited to heat rate, fuel cost, fuel availability, fuel transport, operation and maintenance cost, etc., for at least 150 days after the Proposal Due Date.

   3.2. Any Capacity Payments to the Seller will be based upon guaranteed capacity at the Summer Design Conditions delivered to the Companies' transmission system unless the location of the Seller's facility justifies alternate conditions. Summer Design Conditions shall be the following.

3.2.1. Dry Bulb: 89°F
3.2.2. Mean Coincident Wet Bulb: 78°F

3.3. Seller will guarantee the annual and seasonal availability and describe required maintenance outage schedule.

3.4. Seller should address in their proposal its remedies for failure to meet availability guarantees.

3.5. Seller will be responsible for any and all compliance related cost and fines (environmental, NERC, FERC, etc) incurred due to the non-compliance of the assets designated to supply power to the Companies.

3.6. After the evaluation of proposals is completed, the Companies will enter into negotiations on a timely basis if the Companies determine that a proposal is in their customer's best interests. Any subsequent contracts will be contingent on obtaining the necessary regulatory approvals.

3.7. The Companies termination rights will include, but may not be limited to: (i) failure to obtain all required regulatory approvals, (ii) failure to post or maintain required financial credit requirements, (iii) failure to meet key development and implementation milestones, (iv) failure to meet reliability requirements, and (v) failure to cure a material breach under the Supply Agreement.

4. **Dispatching and Scheduling** (Required Proposal Content) - The Companies prefer flexibility in the utilization of the generation resource being offered by the Seller. The Companies desire, at the Companies' expense, to install equipment at the generator site to facilitate real time control/dispatch of generation to follow load changes and respond to system frequency changes. The Seller should state its desire and willingness to allow and cooperate with the Companies in establishing real-time control of generation.

5. **Ancillary Services** (Required Proposal Content) - Under a Supply Agreement, the Companies desire to have the unrestricted right to utilize all ancillary services associated with generation being offered by the Seller. The Seller should describe the ancillary service capability of its proposal e.g., black start capability, voltage support, load following, energy imbalance, spinning reserve, and supplemental reserve. The ancillary services that would be available to the Companies should not be limited to those defined in this paragraph. The Companies desire to have the unrestricted rights to any future ancillary services defined by the industry and capable of being provided by the generation capacity being offered. In the case where the Companies purchase only part of the generation capacity from a unit, system or facility, then the Companies desire to have unrestricted rights to ancillary services on a prorated basis.

6. **Pricing** (Required Proposal Content) - The Seller's pricing must be a delivered price to the Companies' transmission system. The Companies will be responsible only for Network Integrated Transmission Service (NITS) on the Companies transmission system. Prices must be firm, representing best and final data and quoted in U.S. dollars. If pricing involves escalation or indexing, the details of such pricing, including the specific indices or escalation rates, must be included for evaluation.

   6.1. The Seller's proposal must provide the product and generation characteristics on the attached form. Pricing information can be provided on the form or separately in another format that is appropriate for the offer. The Seller is encouraged to provide as much information as possible to aid in the evaluation of the offer. These attached data forms may be utilized in any filings with regulatory agencies (such as the KPSC) related to this RFP.

7. **Delivery** (Required Proposal Content) - The Companies consider reliable power delivery at the time of the typical summer and winter peak demand of its customers to be of the utmost importance. The delivery point is the Companies' transmission system. Under a Supply Agreement, Sellers would be responsible for providing firm transmission to the Companies' transmission system. The Seller is responsible for all costs associated with transmission interconnections and shall provide all studies and Interconnection Agreements. The Seller is responsible for all transmission reservations, losses and costs including system upgrades up to the delivery point and shall provide all studies and Transmission Reservations/Agreements. All costs associated with interconnections and transmission up to the delivery point should be included in the Seller's pricing where appropriate under current FERC orders and rulings. TranServ International, Inc., 2300 Berkshire Lane North, Minneapolis, Minnesota 55441, is an Independent Transmission Operator that administers the Companies' OATT. Tennessee Valley Authority (TVA) serves as the Companies' Reliability Coordinator (RC). For purposes of the Companies' evaluation of the proposals, the Companies may estimate any transmission costs that are not supported by the appropriate studies including deliverability and the associated voltage support to the Designated Network Load ("DNL") of the Companies. If the Seller has not completed all required transmission studies, it is essential that the following information be provided in order for the Companies to evaluate the proposal:
   - Size of the unit
   - Point of interconnection to the grid
   - Impedance of the generator step-up transformer
   - Transient and sub transient characteristics of the generator

8. **Environmental** - For the sale of generation capacity and energy to the Companies under a Supply Agreement, the Seller would be responsible for obtaining all necessary permits and providing all credits and allowances needed to comply with the

permit requirements for the life of the agreement, where permits, credits and allowances are applicable for the product being sold. Failure to obtain or comply with any environmental permit or governmental consent would not excuse nonperformance by Seller. The Companies require that Sellers provide the following information for evaluation:

- Unit heat rate, fuel specification, and control technologies employed.
- Emissions rates for NOx, SOx, CO, CO2, PM_{10}, and Hg.
- Copy of air permit or permit application if available.
- Timing and status of all permit applications including air, water withdrawal, wastewater disposal, fuel byproducts handling and disposal, etc.

9. **<u>Development Status</u>** – Seller shall provide a comprehensive narrative of the status of the development of any generation project intended to be used to meet Seller's obligations to the Companies. Seller's narrative shall include the following.
   9.1. A comprehensive development and construction schedule,
   9.2. A listing of all required permits and governmental approvals and their status,
   9.3. A listing of all required electric interconnection and or transmission agreements and their status,
   9.4. A financing plan, and
   9.5. A summary of key contracts (fuel, construction, major equipment) to the extent that they exist.

10. **<u>Other Information Requirements</u>** - Sellers shall provide a complete description of the generation facilities that would be used to fulfill the Seller's obligations to the Companies. The description should include the following:

- Seller's operating experience with similar technology.
- Guaranteed capacity rating and heat rate at Summer Design Conditions of:

Dry Bulb	89	F
Wet Bulb	78	F

- Guaranteed capacity rating and heat rate at winter design conditions of:

Dry Bulb	14	F

- Guaranteed capacity rating and heat rate at average day design conditions

Dry Bulb	57	F
Relative Humidity	60	%

- Guaranteed ramp rate in MWs/minute if applicable.

- Guaranteed annual and seasonal availabilities including EFOR values and planned maintenance schedules.
- Technology employed (combined cycle, pulverized coal, CFB, super-critical, etc.)
- Plant location along with proof or status of ownership or control of site.
- Zoning status of plant site.
- If the plant site is subject to site approval by a governmental authority, provide a description of the approval status including a copy of the application. If approval has been granted, provide a copy of the approval.
- Status of engineering and design work.
- Key project participants including owners, operators, engineer/contractors, fuel suppliers

The Seller should also provide any additional information the Seller deems necessary or useful to the Companies in making a definitive and final evaluation of the benefits of the Seller's proposal without further interaction between the Companies and Seller.

11. **Financial Capability** - Should the Companies elect to enter into an agreement with a Seller who fails to meet its obligations at any point in time, the Companies' customers may be exposed to the risk of higher costs. Therefore, the Sellers will be required to demonstrate, in a manner acceptable to the Companies, the Seller's ability to meet all financial obligations to the Companies throughout the applicable development, construction and operations phases for the term of the Supply Agreement. Under no circumstances, should the Companies' customers be exposed to increased costs relative to the cost defined in an agreement between the Seller and the Companies.

    11.1. At all times, the Seller will be required to maintain an investment grade credit rating with either S&P or Moody's or have a parent guarantee from an investment grade entity that meets the approval of the Companies.

    11.2. Upon execution of the Supply Agreement, Sellers will be required to post a letter of credit ("LOC") to protect the Companies' customers in the event of default by the Seller. The exact amount of a LOC will be subject to approval by the Companies based upon the Companies' models. This amount shall take into account the cost of replacement energy and associated environmental cost with the production of replacement energy and any byproducts of such replacement energy. If the Companies draw down the LOC amount at any time, the Seller must replace the LOC to the original value within five days.

12. **Alternate Power Supplies** - Alternate power supply arrangements may include the acquisition of generation assets, existing generation facilities, projects under development, system firm products, or other power supply arrangements that meet the Companies' requirements described in this RFP. The Seller must make all transmission arrangements for the delivery of alternate power supply arrangements to

the delivery point and include the cost for transmission in the pricing. Sellers interested in proposing alternative power supplies must provide all information specified in this document and applicable to the alternate power supply needed for the Companies to fully evaluate the proposal. Those Sellers proposing the sale of generation facilities should include the following:

- Complete description of the facilities included in the sale.
- Firm offer price
- Term sheet which identifies key terms and conditions
- Latest condition report
- Projected operating data including output, heat rate, and forced outage rate as appropriate
- Projected operating expenses and capital expenditures
- For existing facilities, provide historical operating data, operating expenses, and capital expenditures for a minimum of the latest five years or since the start of commercial operation if in commercial operation for less than five years.

13. **<u>RFP Schedule</u>** - All proposals must be complete in all material respects and be received no later than 4 p.m. EDT on Friday, November 2, 2012. Email proposals must be followed up with a signed original within two business days.

RFP Issued	Friday, September 7, 2012
Proposals Due	Friday, November 2, 2012
Evaluation Completed	Friday, March 15, 2013

Proposals will not be viewed until 4 p.m. EDT on Friday, November 2, 2012. After the evaluation of proposals is completed, the Companies will enter into negotiations on a timely basis if the Companies determine that a proposal is in their customer's best interests. Any subsequent contracts will be contingent on obtaining the necessary regulatory approvals.

14. **<u>Treatment of Proposals</u>**

14.1. The Companies reserve the right, without qualification, to select or reject any or all proposals and to waive any formality, technicality, requirement, or irregularity in the proposals received. The Companies also reserve the right to modify the RFP or request further information, as necessary, to complete its evaluation of the proposals received.

14.2. Sellers who submit proposals do so without recourse against the Companies for either rejection by the Companies or failure to execute an agreement for purchase of capacity and/or energy for any reason. Sellers are responsible for any and all costs incurred in the preparation and submission of a proposal and/or any subsequent negotiations regarding a proposal.

15. **Confidentiality** - As regulated utilities, it is expected that the Companies will be required to release proposal information to various government agencies and/or others as part of a regulatory review or legal proceeding. The Companies will use reasonable efforts to request confidential treatment for such information to the extent it is labeled in the proposal as "Confidential." Please note that confidential treatment is more likely to be granted if limited amounts of information are designated as confidential rather than large portions of the proposal. However, the Companies cannot guarantee that the receiving agency, court, or other party will afford confidential treatment to this information. Subject to applicable law and regulations, the Companies also reserve the right to disclose proposals to their officers, employees, agents, consultants, and the like (and those of its affiliates) for the purpose of evaluating proposals. Otherwise, the Companies will not disclose any information contained in the Seller's proposal that is marked "Confidential," to another party except to the extent that (i) such disclosures are required by law or by a court or governmental or regulatory agency having appropriate jurisdiction, or (ii) the Companies subsequently obtain the information free of any confidentiality obligations from an independent source, or (iii) the information enters the public domain through no fault of the Companies.

16. **Contacts** - All correspondence should be directed to:

Charles A. Freibert, Jr.
Director Marketing
LG&E and KU Energy LLC
Energy Services
220 West Main Street
Louisville, KY 40202

E-mail: charlie.freibert@lge-ku.com
Phone: 502-627-3673

In closing, I look forward to your response by 4 p.m. EDT on Friday, November 2, 2012, and the possibility of doing business to meet the Companies' future power needs. Your interest in this request is greatly appreciated. Please contact me if you have any questions and would like to discuss further. For immediate concerns in my absence, please contact Donna LaFollette at 502-627-4765.

Sincerely,

Charles A. Freibert, Jr.

LG&E and KU RFP Data Form

Note to bidder: Provide a separate term sheet for each different "Term of Contract" or capacity offering

Seller ____

Product and Generation Characteristics:
Proposal Description____

____

____

____

Generation Source Description ______________________________________
Transmission Interconnection Point of the Source ____________________________
Point of interconnection to the grid ______________________________________
Fuel Commodity Price (if applicable) ____________________
Firm Fuel Transport Price (if applicable)
Start Date and Term of Contract ______________________________________
Summer Firm Capacity Amount ________ MW
Summer Maximum Dispatch Capacity Amount (if applicable) ________MW
Summer Minimum Dispatch Capacity Amount (if applicable) ________ MW
Guaranteed Heat Rate (or heat rate curve) (if applicable) ________Btu/kwh
Winter Firm Capacity Amount ________ MW
Winter Maximum Dispatch Capacity Amount (if applicable) ________MW
Winter Minimum Dispatch Capacity Amount (if applicable) ________MW
Output in 10 minutes ________MW
Guaranteed Ramp capability ________MW/minute (if applicable)
Start-up time to minimum capability ______________________________
Start-up time to maximum capability ______________________________
Minimum run time ________________________
Minimum down time ______________________
Constraints on production time (if applicable) ________________________
Forced Outage Rate _______________%
Guaranteed Availability ______________________________________
Planned Outage Schedule ______________________________________

Pricing Information (provide a separate pricing form if applicable):
Sale Price __________ or, Capacity Price ________________ ($/MW-yr)
Year of Capacity Price Quote ________________
Capacity Price Escalation/Year or Index________________
Fixed O&M______________($/MWH or $/MW-yr)
Year of Fixed O&M Price Quote ____
Fixed O&M Price Excalation/yr or Index_________
Energy Pricing (Provide energy pricing in one of the following formats)

1. Fixed Energy price over the term ____________($/MWH)
2. Escalating Price Over Term__________ ($/MWh) escalating at ____ % per year
3. Production Cost: Variable O&M + Guaranteed Heat Rate * Fuel Price over Term
    a. Variable O&M ___________ ($/MWh)
    b. Guaranteed Heat Rate _______ (Btu/kwh)
    c. Fuel Price ___________

Note: Energy pricing to include all ancillary service costs, taxes and other fees necessary for delivery of the energy to the Delivery Point.

The Companies reserve the right to disclose proposals to the KY PSC under a statement of confidentiality.

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

Response to Commission Staff's Second Request for Information dated February 11, 2013

February 28, 2013

Item 19) ***Refer to pages 22-23 of the Berry Testimony, specifically, the discussion of Big Rivers' deferring the backfilling of production vacancies since receiving the notice of Century Aluminum of Kentucky General Partnership's ("Century") termination of its Retail Electric Service Agreement with Kenergy Corp. Explain what impact this deferral has on Big Rivers' production expense, non-fuel, in the forecast period.***

Response) In the forecasted test year, Big Rivers removed 92 employees from its current full-complement of headcount. Hence, deferring the backfilling of production vacancies since receiving the Century termination notice has no impact on Big Rivers' production expense, non-fuel, in the forecast period.

Witness) Robert W. Berry

BIG RIVERS ELECTRIC CORPORATION

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

Response to Commission Staff's Second Request for Information dated February 14, 2013

February 28, 2013

Item 20) ***Refer to pages 23-24 of the Berry Testimony and Exhibit Wolfram-2, page 12 of 14, to the Direct Testimony of John Wolfram ("Wolfram Testimony").***

a. Mr. Berry discusses the plan to idle the Wilson Station and the related reduction of 92 positions due to production curtailments caused by Century's termination. The Wolfram exhibit shows the calculation of an adjustment to eliminate "Non-Recurring Labor Related to Wilson Layup." Confirm that this adjustment is not intended to reflect the reduction of 92 positions referenced in the Berry Testimony.

b. Provide the amount by which Big Rivers' labor expenses are lower in the forecast period due to the reduction of the 92 positions. Indicate where in the application this expense reduction is shown.

Response)

a. Confirmed. The proposed adjustment is not intended to reflect the full reduction of 92 positions; rather, the adjustment is intended to remove a small portion of those labor costs that were not already reduced in Big Rivers' budget by September 1, 2013 (when the fully forecasted test period begins).

b. Big Rivers' labor expenses are lower in the forecasted test period than they otherwise would be due to the reduction of the 92 positions. The full amount is not shown in the application because it is built into Big Rivers' budget, and thus is already excluded from the fully forecasted test period expense amounts. Big Rivers estimates that the full cost related to the reduction of 92 positions is $10,432,610. See attached worksheet. This includes the amount quantified in Reference Schedule 1.10 of Exhibit Wolfram-2.

Witnesses) James V. Haner and John Wolfram

Big Rivers Electric Corporation
Case No. 2012-00535

Attachment to Response for PSC 2-20(b)
Wilson Layup Backup Data

Total Reduction in Headcount		92
Bargaining unit (BU) employees		62
Non BU employees		30
Total cost for 3 months (per Exhibit Wolfram-2)	$	2,595,458
Average cost per month	$	865,153
Average monthly BU burdened labor expense during the FTP	$	9,403.83
Average monthly non-BU burdened labor expense prior to raise in January 2014 (Sep 13 to Dec 13)	$	9,403.83
Average monthly non-BU burdened labor expense after raise in January 2014 (Jan 14 to Aug 14)	$	9,615.42

Savings Calculation:		
BU total for 62 employees x 12 months	$	6,996,450
Non BU total for 30 employees x 12 months		3,436,160
Total estimated savings for reduction in headcount during FTP	**$**	**10,432,610**

BIG RIVERS ELECTRIC CORPORATION

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

Response to Commission Staff's Second Request for Information dated February 14, 2013

February 28, 2013

Item 21) ***Refer to the Berry Testimony, page 23, regarding the decision to idle the Wilson station.***

a. Explain the process that Big Rivers must follow to obtain approval from the Midwest Independent System Operator ("Midwest ISO") to idle, or layup, the Wilson station. If Big Rivers has begun the process of obtaining Midwest ISO approval, indicate when the process began and when Big Rivers anticipates a decision from the Midwest ISO. Provide the request to the Midwest ISO seeking such approval. If Big Rivers has not begun the process, indicate when it will begin the process to obtain the Midwest ISO's approval to idle the Wilson station.

b. Provide a general description of the steps needed to idle Wilson station.

c. How long does Big Rivers intend to idle the Wilson station?

d. What are the attendant risks (i.e., federal air emissions compliance, allocation allowances, etc.) with the decision to idle the Wilson station?

e. What is the distinction, if any, between mothballing and idling a power plant?

f. At lines 11-14, it is stated that "Big Rivers assumed that if the Century facility continues to operate in any

substantial way on or after August 20, 2013, MISO would require Big Rivers to continue to operate the Coleman Station for system reliability reasons."

1. ***Provide all supporting documents for this statement, including any correspondence, communications, studies, or analyses, whether internal or external to Big Rivers, which discuss the need for the Coleman Station to be operational if Century continues to operate.***
2. ***Define the term "substantial" as used in the Berry Testimony.***
3. ***If the Coleman Station is required to be operational to support Century, explain which of the three units at the Coleman Station would have to be operational and the reasons why each unit must be operational.***

g. If Century does not continue to substantially operate its Hawesville facility on or after August 20, 2013, explain whether there would be cost savings or other factors that would support idling the Coleman Station rather than idling the Wilson Station. Provide a detailed cost analysis comparing the idling of the Coleman Station versus the idling of the Wilson Station.

Response)

a. In order to obtain approval from MISO to idle the Wilson Station, Big Rivers would be required to file an Attachment Y, "Notification of Potential Generation Resource/SCU Change of Status," in accordance with Section 38.2.7.a of the MISO Tariff. MISO would then study the request and determine if the particular generation resource(s) is needed for system reliability. If MISO determined the generation resource(s) was not needed for system reliability, Big Rivers would suspend operation of the unit per the date specified in the Attachment Y notification. If MISO determined the resource(s) was needed for system reliability, an Attachment Y-1, "Standard Form Support Supply Resource (SSR) Agreement" would be negotiated with MISO to reimburse Big Rivers to the keep the resource operating until MISO determined it was not needed. Costs would be shared based on the proportional impact of the resource on affected load serving entities ("LSEs") as determined by MISO. The cost reimbursement in the SSR agreement would be subject to Federal Energy Regulatory Commission ("FERC") approval. The full MISO tariff with the referenced Attachments Y and Y-1 is available at the following link:

https://www.misoenergy.org/Library/Tariff/Pages/Tariff.aspx.

Big Rivers has not filed an Attachment Y with MISO; however, in an effort to understand whether MISO will allow Big Rivers to idle generation, Big Rivers submitted to MISO an Attachment Y-2, Request for Non-Binding Study Regarding Potential SSR Status for Big Rivers' Coleman Station on December 19, 2012. On December 27, Big Rivers submitted to MISO an Attachment Y-2, Request for Non-Binding Study Regarding Potential SSR Status for Big Rivers' Wilson Station. A copy of each request is attached hereto. Per MISO's tariff, MISO estimates that the Attachment Y-2 analysis will take 75 days. Big Rivers anticipates receiving results from MISO in early to mid-March.

b. Please see general steps below:

(1) Obtain approval from MISO to lay-up Wilson Station.

(2) Remove Wilson Station from service per the lay-up procedure.

(3) Implement the attached lay-up procedure to protect Wilson Station's unit components.

(4) Monitor Wilson Station's unit components per the lay-up procedure.

For more detailed information, a copy of the Wilson Station Plant Lay-up Plan is provided on the PUBLIC CDs accompanying these responses. Please understand the attached document is a living document and changes/updates will be made as new information and details become available.

c. Wilson Station will be idled until such time as the off-system power market increases above the all-in cost (fixed and variable) of operating the plant less the costs of lay-up, or until such time Big Rivers is successful in acquiring a new load to replace the available capacity as a result of Century's exit. Big Rivers' current long-term Financial Model indicates Wilson Station will restart in 2019. Wilson Station will be available to operate as needed to cover outages at other stations and to maintain its current environmental permits. Please note the current Financial Model does not have any load recovery projected and forecasted market power prices could change.

d. Big Rivers will continue to monitor, collect, and report data at Wilson Station as required by all environmental permits (air, water and waste management) currently in place. Under the current Clean Air Interstate Rule (CAIR) program, Big Rivers will continue to receive SO_2 and NOx allowances associated with the Wilson Station. Big Rivers does not foresee any impacts to the environmental permits needed to operate by laying up the unit for a limited period of time. Big Rivers will evaluate the potential for any new environmental regulations that might impact the unit prior to the restart of the Wilson Station.

e. In IEEE Std 762-2006, there are three identified deactivated shutdown states: (1) Inactive Reserve, (2) Mothballed, and (3) Retired. The definitions of these states from IEEE Std 762-2006 are provided below.

- Inactive Reserve – State where unit is unavailable for service, but can be brought back into service in a relatively short period of time, typically measured in days.
- Mothballed – State where unit is unavailable for service, but can be brought back into service with the appropriate amount of notification, typically weeks or months.
- Retired – State where unit is unavailable for service and is not expected to return to service in the future.

Big Rivers believes the Wilson lay-up would fit under the definition of Mothballed.

f.

1. In addition to general operational experience and knowledge, Big Rivers based the statement on a preliminary internal evaluation summarized in the memorandum attached to this response as well as a detailed study prepared for Century Aluminum by Siemens dated October 19, 2012. Big Rivers has not

received permission from Century to provide the Siemens report.

2. The term "substantial" as used in the Berry Testimony should be defined as "similar to current operating characteristics" or consuming 400 MW or more of energy at a 95% load factor.
3. If Coleman Station is required to continue operating to support a substantial Century load, Big Rivers believes that at least two units will need to be available for operation at all times; however, MISO will make the final determination based on its flow study. All three Coleman units have essentially the same generating capacity.

g. A detailed cost analysis of laying up Wilson Station compared to laying up Coleman Station has not been completed at this time. Please see the attachment to this response comparing Wilson and Coleman production and capital costs if both were operating and how each station will be impacted with proposed future environmental laws. However, it should be noted that the compliance dates with these proposed future environmental laws are unknown at this time.

Witness) Robert W. Berry

Big Rivers
ELECTRIC CORPORATION

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

December 18, 2012

MISO
ATTN: Director of Transmission Expansion Planning
720 City Center Drive
Carmel, IN 46032

Dear Sir:

Enclosed please find ATTACHMENT Y-2 Request for Non-Binding Study Regarding Potential SSR Status and the $70,000 check.

If you have any questions, please feel free to contact me.

Sincerely,

Robert W. Berry

Robert W. Berry
Vice President Production
Big Rivers Electric Corporation

Enclosures

/jw

ATTACHMENT Y-2

Request for Non-Binding Study Regarding Potential SSR Status

This is a request that the Transmission Provider conduct a non-binding study of the reliability impacts related to a potential change of status of a portion or all of either a Generation Resource or a Synchronous Condenser Unit ("SCU"). An electronic copy of the completed form will be accepted by the Transmission Provider, however, the study application will not be considered complete until the original form containing an original signature, including all attachments, and the study deposit funds are received by the Transmission Provider at the following address:

MISO
Attention: Director of Transmission Expansion Planning
720 City Center Drive
Carmel, IN 46032.

Name of Market Participant owning and/or operating the Generation Resource or SCU
Big Rivers Electric Corporation (BRPS)

Type of interest in Generation Resource: ☒ Owner of Generation Resource
☐ Operator of Generation Resource

Name of Market Participant owning and/or operating the Synchronous Condenser Unit ("SCU")

Type of interest in SCU: ☐ Owner of SCU
☐ Operator of SCU

Market Participant's state of organization or incorporation Kentucky

Generation Resource/SCU [plant name(s), unit number(s), and unit's maximum net output]

Coleman Unit 1 (BREC.COLE1), 150 MW
Coleman Unit 2 (BREC.COLE2), 138 MW
Coleman Unit 3 (BREC.COLE3), 155 MW

Market Participant is considering whether to make unavailable a Generation Resource/SCU, and hereby requests a study at Market Participant's expense to determine the impact of removing the Generation Resource/SCU from service, as specified below.

The start date for the potential removal from service is the 20th day of Aug, 2013.

The return to service date to be assumed for the purpose of the requested study is the 1st day of Jan, 2015.

Additional operational limits to be considered in the evaluation are described below:

See attachment.

The Transmission Provider may request additional information as reasonably necessary to conduct the subject study. If the Market Participant does not provide all of the information requested by the Transmission Provider in a timely manner, then the Transmission Provider may be unable to complete the study within 75 days and will so advise the Market Participant.

The Market Participant understands and agrees that the results of this request for a study will not be Confidential Information under the Transmission Provider's Tariff if the Market Participant declines to rescind the Attachment Y-2 request after receiving notice that the subject study has been completed by the Transmission Provider pursuant to Section 38.2.7(m). The Transmission Provider will make the results of the study public by posting the information on

OASIS for informational purposes at the same time that the results of the study are provided to the Market Participant. A Market Participant will have the right to rescind the request for an informational study by notifying the Transmission Provider prior to its completion of the informational study. In the event of a rescission of an informational study request, the Market Participant shall remain liable for all expenses incurred by the Transmission Provider in conducting the study up until notice of rescission, however the Transmission Provider shall not post any study results on OASIS or release the results to the Market Participant. This request for a non-binding study is not intended to constitute an offer to enter into a binding SSR Agreement pursuant to Section 38.2.7 of the Tariff, but is intended only as a request for a non-binding study of the transmission reliability impacts of a potential future status change of the Generation Resource/SCU.

The Market Participant is enclosing a study deposit of $70,000 made payable to the Transmission Provider, as partial payment for the study's costs and expenses. The Transmission Provider shall invoice the Market Participant for all costs and expenses reasonably incurred in excess of the deposit amount, or shall refund any remaining portion of such deposit, upon completion of the non-confidential study. The Market Participant agrees to pay all such invoices.

The Transmission Provider shall use Reasonable Efforts to complete the evaluation no later than seventy-five (75) Calendar Days from the date of receipt of the deposit and completed Attachment Y-2 for the non-confidential study request. The Market Participant agrees that: (1) the results of such non-confidential study will only provide the Market Participant with a probability of the outcome if the Market Participant later elects to submit an Attachment Y form under the terms of Section 38.2.7 of the tariff; (2) such study results will not necessarily be binding upon the Transmission Provider if an Attachment Y notification is later made, except as provided for under Section 38.2.7(n) of the Tariff; and (3) the study is being made to explore options and does not mean that the Market Participant has made any decisions about the future status of the facility.

The undersigned certifies that I am an officer of the Market Participant that owns or operates the subject Generation Resource/SCU, that I am authorized to execute and submit this study request on behalf of subject Generation Resource/SCU, and that the statements contained herein are true and correct.

Robert W Berry

Signature

Name: Robert W. Berry

Title: VP of Production

Date: 12-17-12

Contact phone number: (270) 844-6186

Contact email address: bob.berry@bigrivers.com

Certification

STATE OF Kentucky

COUNTY OF Henderson

Before me, the undersigned authority, this day appeared Robert W. Berry, known by me to be the person whose name is subscribed to the foregoing instrument, who, after first being sworn by me deposed and said:

"I am an officer of Big Rivers Elect. Corp., I am authorized to execute and submit the foregoing study request on behalf of Big Rivers Elect. Corp., and the statements contained in such application are true and correct."

SWORN TO AND SUBSCRIBED TO BEFORE ME, the undersigned authority on this the

17 day of December, 2012

Joy P. Wright

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

My Commission expires

Attachment to Big Rivers Electric Attachment Y-2 Study Request for Coleman Units 1, 2 and 3

Big Rivers requests that MISO evaluate two scenarios for this Attachment Y-2 study

Scenario 1: Century Aluminum ceases operations on August 19, 2013

Scenario 2: Century Aluminum continues normal operations

Century Aluminum load is presently represented at the following EPNodes under the BREC.BREC CPNode.

L BREC COLEMABR NSA0
L BREC COLEMABR NSA1
L BREC COLEMABR NSA2
L BREC COLEMABR NSA3
L BREC COLEMABR NSA4

For the Attachment Y-2 study, additional information/request:

Scenario 1: Century Aluminum ceases operations on August 19, 2013

- The demand and energy forecasts submitted to MISO on November 1, 2012, via the New MECT tool reflect Century load dropping from 482 MW at a 0.98 load factor on August 19, 2013 to 0 MW on August 20, 2013.
- If MISO determines there is a reliability concern and a SSR (System Support Resource) Agreement is needed that an estimate of the cost allocation percentages among affected LSE's (Load Serving Entity) also be determined.

Scenario 2: Century Aluminum continues normal operations

- Add a Century load of 482 MW at a 0.98 load factor continuing after August 19, 2013 to the demand and energy forecasts submitted to MISO on November 1, 2012 via the New MECT tool. The load shape is a flat line.
- If MISO determines there is a reliability concern and a SSR Agreement is needed that an estimate of the cost allocation percentages among affected LSE's also be determined. When estimating the cost allocation percentages, assume that the Century load at the above EPNodes will be under a new CPNode that is under a LSE/Asset Owner/Market Participant other than Big Rivers.

ENDORSEMENT OF ATTACHED CHECK WILL ACKNOWLEDGE PAYMENT IN FULL OF ITEMS SET FORTH BELOW

VENDOR NO
80329

Big Rivers Electric
P.O. Box 24
201 Third Street

NO. 525252
DATE 18-Dec-12

DATE	INVOICE NUMBER	DESCRIPTION	GROSS AMOUNT	DISCOUNT	NET AMOUNT
17-Dec-12	13138	DEPOSIT FOR ATT Y-2 STUDY FOR CO	70,000.00	0.00	70,000.00
TOTALS			70,000.00	0.00	70,000.00

REMOVE DOCUMENT ALONG THIS PERFORATION

THIS DOCUMENT IS PRINTED IN TWO COLORS. DO NOT ACCEPT UNLESS BLUE AND BURGUNDY ARE PRESENT.

Big Rivers Electric
P.O. Box 24
201 Third Street
Henderson,KY 42420

Old National Bank
Member Old National Bancorp
P O Box 718 * Evansville, IN 47705

71-1
863

VOID AFTER 6 MONTHS
AFTER THIS DATE

NO. 525252

DATE	NET AMOUNT
18-Dec-12	$********70,000.00

PAY Seventy Thousand Dollars And Zero Cents******************

TO THE ORDER OF
MIDWEST ISO ACCTS RECEIVABLE
PO BOX 4202
CARMEL,IN 46082-4202

Mark A. Bailey
SIGNATURE

Billie J. Richert
SIGNATURE

⑈525252⑈ ⑆086300012⑆ 10585559⑈

Big Rivers Electric
P.O. Box 24
201 Third Street
Henderson,KY 42420

MIDWEST ISO ACCTS RECEIVABLE
PO BOX 4202
CARMEL,IN 46082-4202
United States

SEE REVERSE SIDE FOR OPENING INSTRUCTIONS

Big Rivers
ELECTRIC CORPORATION

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

December 26, 2012

MISO
ATTN: Director of Transmission Expansion Planning
720 City Center Drive
Carmel, IN 46032

Dear Sir or Madam,

Enclosed please find Big Rivers' Attachment Y-2 Request for Non-Binding Study Regarding Potential SSR Status. Also enclosed is the $70,000 check required for the study.

Please note that Big Rivers submitted a similar request last week for its Coleman facility. Big Rivers is currently evaluating to determine its best option for temporarily reducing generation in its territory.

Please note that Big Rivers would like you to consider each request individually. When evaluating the impact of removing Wilson from service, please assume that Coleman remains in operation. Likewise, when evaluating the impact of removing Coleman from service, please assume that Wilson remains in operation.

If you have any questions, please feel free to contact me at 270.844.6186.

Sincerely,

Robert W. Berry

Robert W. Berry
Vice President Production
Big Rivers Electric Corporation

/lb

ATTACHMENT Y-2

Request for Non-Binding Study Regarding Potential SSR Status

This is a request that the Transmission Provider conduct a non-binding study of the reliability impacts related to a potential change of status of a portion or all of either a Generation Resource or a Synchronous Condenser Unit ("SCU"). An electronic copy of the completed form will be accepted by the Transmission Provider, however, the study application will not be considered complete until the original form containing an original signature, including all attachments, and the study deposit funds are received by the Transmission Provider at the following address:

MISO
Attention: Director of Transmission Expansion Planning
720 City Center Drive
Carmel, IN 46032.

Name of Market Participant owning and/or operating the Generation Resource or SCU
Big Rivers Electric Corporation (BRPS)

Type of interest in Generation Resource: ☒ Owner of Generation Resource
☐ Operator of Generation Resource

Name of Market Participant owning and/or operating the Synchronous Condenser Unit ("SCU")

Type of interest in SCU: ☐ Owner of SCU
☐ Operator of SCU

Market Participant's state of organization or incorporation Kentucky

Generation Resource/SCU [plant name(s), unit number(s), and unit's maximum net output]
Wilson Unit 1 (BREC.WILSON1), 417 MW

Market Participant is considering whether to make unavailable a Generation Resource/SCU, and hereby requests a study at Market Participant's expense to determine the impact of removing the Generation Resource/SCU from service, as specified below.

The start date for the potential removal from service is the 20th day of Aug, 2013.

The return to service date to be assumed for the purpose of the requested study is the 1st day of Jan, 2015.

Additional operational limits to be considered in the evaluation are described below:

See attachment.

The Transmission Provider may request additional information as reasonably necessary to conduct the subject study. If the Market Participant does not provide all of the information requested by the Transmission Provider in a timely manner, then the Transmission Provider may be unable to complete the study within 75 days and will so advise the Market Participant.

The Market Participant understands and agrees that the results of this request for a study will not be Confidential Information under the Transmission Provider's Tariff if the Market Participant declines to rescind the Attachment Y-2 request after receiving notice that the subject study has been completed by the Transmission Provider pursuant to Section 38.2.7(m). The Transmission Provider will make the results of the study public by posting the information on

OASIS for informational purposes at the same time that the results of the study are provided to the Market Participant. A Market Participant will have the right to rescind the request for an informational study by notifying the Transmission Provider prior to its completion of the informational study. In the event of a rescission of an informational study request, the Market Participant shall remain liable for all expenses incurred by the Transmission Provider in conducting the study up until notice of rescission, however the Transmission Provider shall not post any study results on OASIS or release the results to the Market Participant. This request for a non-binding study is not intended to constitute an offer to enter into a binding SSR Agreement pursuant to Section 38.2.7 of the Tariff, but is intended only as a request for a non-binding study of the transmission reliability impacts of a potential future status change of the Generation Resource/SCU.

The Market Participant is enclosing a study deposit of $70,000 made payable to the Transmission Provider, as partial payment for the study's costs and expenses. The Transmission Provider shall invoice the Market Participant for all costs and expenses reasonably incurred in excess of the deposit amount, or shall refund any remaining portion of such deposit, upon completion of the non-confidential study. The Market Participant agrees to pay all such invoices.

The Transmission Provider shall use Reasonable Efforts to complete the evaluation no later than seventy-five (75) Calendar Days from the date of receipt of the deposit and completed Attachment Y-2 for the non-confidential study request. The Market Participant agrees that: (1) the results of such non-confidential study will only provide the Market Participant with a probability of the outcome if the Market Participant later elects to submit an Attachment Y form under the terms of Section 38.2.7 of the tariff; (2) such study results will not necessarily be binding upon the Transmission Provider if an Attachment Y notification is later made, except as provided for under Section 38.2.7(n) of the Tariff; and (3) the study is being made to explore options and does not mean that the Market Participant has made any decisions about the future status of the facility.

The undersigned certifies that I am an officer of the Market Participant that owns or operates the subject Generation Resource/SCU, that I am authorized to execute and submit this study request on behalf of subject Generation Resource/SCU, and that the statements contained herein are true and correct.

Robert W Berry

Signature

Name: Robert W. Berry

Title: VP of Production

Date:

Contact phone number: (270) 844-6186

Contact email address: bob.berry@bigrivers.com

Attachment to Big Rivers Electric Attachment Y-2 Study Request for Wilson Unit 1

Big Rivers requests that MISO evaluate two scenarios for this Attachment Y-2 study
Scenario 1: Century Aluminum ceases operations on August 19, 2013
Scenario 2: Century Aluminum continues normal operations

Century Aluminum load is presently represented at the following EPNodes under the BREC.BREC CPNode.
L BREC COLEMABR NSA0
L BREC COLEMABR NSA1
L BREC COLEMABR NSA2
L BREC COLEMABR NSA3
L BREC COLEMABR NSA4

For the Attachment Y-2 study, additional information/request:

Scenario 1: Century Aluminum ceases operations on August 19, 2013

- The demand and energy forecasts submitted to MISO on November 1, 2012, via the New MECT tool reflect Century load dropping from 482 MW at a 0.98 load factor on August 19, 2013 to 0 MW on August 20, 2013.
- If MISO determines there is a reliability concern and a SSR (System Support Resource) Agreement is needed that an estimate of the cost allocation percentages among affected LSE's (Load Serving Entity) also be determined.

Scenario 2: Century Aluminum continues normal operations

- Add a Century load of 482 MW at a 0.98 load factor continuing after August 19, 2013 to the demand and energy forecasts submitted to MISO on November 1, 2012 via the New MECT tool. The load shape is a flat line.
- If MISO determines there is a reliability concern and a SSR Agreement is needed that an estimate of the cost allocation percentages among affected LSE's also be determined. When estimating the cost allocation percentages, assume that the Century load at the above EPNodes will be under a new CPNode that is under a LSE/Asset Owner/Market Participant other than Big Rivers.

Certification

STATE OF

COUNTY OF

Before me, the undersigned authority, this day appeared Robert W Berry, known by me to be the person whose name is subscribed to the foregoing instrument, who, after first being sworn by me deposed and said:

"I am an officer of Big Rivers Electric, I am authorized to execute and submit the foregoing study request on behalf of Big Rivers Electric, and the statements contained in such application are true and correct."

SWORN TO AND SUBSCRIBED TO BEFORE ME, the undersigned authority on this the 21st day of December, 2012

Notary Public, State of Kentucky

My Commission expires May 6, 2014

ENDORSEMENT OF ATTACHED CHECK WILL ACKNOWLEDGE PAYMENT IN FULL OF ITEMS SET FORTH BELOW

VENDOR NO
80329

Big Rivers Electric
P.O. Box 24
201 Third Street

NO. 525483
DATE 21-Dec-12

DATE	INVOICE NUMBER	DESCRIPTION	GROSS AMOUNT	DISCOUNT	NET AMOUNT
19-Dec-12	13173	DEPOSIT FOR ATT Y-2 STUDY FOR WIL	70,000 00	0 00	70,000.00
TOTALS			70,000.00	0.00	70,000.00

REMOVE DOCUMENT ALONG THIS PERFORATION

THIS DOCUMENT IS PRINTED IN TWO COLORS. DO NOT ACCEPT UNLESS BLUE AND BURGUNDY ARE PRESENT.

Big Rivers Electric
P.O. Box 24
201 Third Street
Henderson,KY 42420

Old National Bank
Member Old National Bancorp
P O Box 718 * Evansville , IN 47705

71-1
863

NO. 525483

VOID AFTER 6 MONTHS
AFTER THIS DATE

DATE	NET AMOUNT
21-Dec-12	$********70,000.00

PAY Seventy Thousand Dollars And Zero Cents******************

Mark A. Bailey
SIGNATURE

TO THE ORDER OF
MIDWEST ISO ACCTS RECEIVABLE
701 CITY CENTER DRIVE
CARMEL,IN 46032

Billie J. Richert
SIGNATURE

⑈525483⑈ ⑆086300012⑆ 10585559⑈

Big Rivers Electric
P.O. Box 24
201 Third Street
Henderson,KY 42420

MIDWEST ISO ACCTS RECEIVABLE
701 CITY CENTER DRIVE
CARMEL,IN 46032
United States

SEE REVERSE SIDE FOR OPENING INSTRUCTIONS

Big Rivers
ELECTRIC CORPORATION

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

TO: David Crockett

FROM: Chris Bradley

DATE: May 23, 2012

SUBJECT: Smelter Studies

As requested, the power flow studies necessary to evaluate a temporary idling of either the entire Coleman Generation Station or the Wilson Generating Station have been performed. Both smelters were assumed to be operating at full capacity. All studies were performed with a 2015 summer peak model. The 345 kV Vectren interconnection and all phase two improvements were assumed to be in-service. A brief summary of each situation follows:

Coleman Station Idled

Base Conditions (no additional outages) - Coleman switchyard voltage: 157 kV; Newtonville to Coleman 161 kV line loading: 85%. While above the voltage criteria (153 kV Base), the reduced base voltage is a concern.

Coleman EHV to Daviess Co. EHV 345 kV Line Outage - Coleman switchyard voltage: 135 kV; Newtonville to Coleman 161 kV line loading: 150%. With bus voltages well below the voltage criteria (148 kV N-1) and a significant line overload, unacceptable conditions could be expected with peak and off-peak loads.

Reid to Daviess Co. 161 kV Line Outage - Coleman switchyard voltage: 152 kV; Daviess County voltage: 145 kV; Newman voltage: 143 kV; Newtonville to Coleman 161 kV line loading: 101%. With bus voltages well below the voltage criteria (148 kV N-1) and a slight line overload, unacceptable conditions could be expected with various load levels.

Coleman to Newtonville 161 kV Line Outage - Coleman switchyard voltage: 154 kV. While above the voltage criteria (148 kV N-1), the reduced voltage is a concern.

Wilson Station Idled

Various transmission and generation outages have been evaluated coincident with an outage of the Wilson station. No unacceptable voltages or facility loadings have been identified through these studies. While a significant number of scenarios have been studied, the study should not be considered a comprehensive evaluation.

Big Rivers Electric Corporation
Case No. 2012-00535

Attachment to Response PSC 2-21(g)
Production Costs and Capital

Production Variable Cost, $/MWH				
Station	2013	2014	2015	2016
Coleman	[redacted]			
Wilson				

Production O&M Fixed Cost including Labor, $/MWH				
Station	2013	2014	2015	2016
Coleman	[redacted]			
Wilson				

Capital Cost, $				
Station	2013	2014	2015	2016
Coleman	[redacted]			
Wilson				

Big Rivers Electric Corporation
Case No. 2102-00535

Attachment to Response for PSC 2-21(g)

Possible Future Environmental Compliance Requirements						
	Coleman Station (443 MW Net Capacity)			Wilson Station (417 MW Net Capacity)		
Pollutant/Law	Capital Cost, $	Annual O&M Cost, $	Comment	Capital Cost, $	Annual O&M Cost, $	Comment
Mercury Air Toxins Standard (MATS)	$ 28,440,000	$ 3,360,000	Current ECP plan; compliance in April, 2015	$ 11,240,000	$ 2,710,000	Current ECP plan; compliance in April, 2015
SO_2 Emissions (CAIR) - FGD	$ -	$ 1,975,000	Compliant today or purchase allowances - New law expected 1-2 years with 3-4 years to comply (Annual O&M in 2012 $)	$ -	$ 1,400,000	Compliant today or purchase allowances - New law expected 1-2 years with 3-4 years to comply (Annual O&M in 2012 $)
NO_x Emissions (CAIR) - SCR	$ -	$ -		$ -	$ 1,500,000	
EPA 316(b)*	$ 4,000,000	$ 750,000	2011 $, Rotating circular screen with fish pump	$ -	$ -	Compliant with law today
Coal Combustion Residuals (CCR)* Assume Subtitle D	$ 38,000,000	$ 1,250,000	2011 $, Install remote submerged scraper conveyor and convert to vacuum fly ash dewatering bin system	$ -	$ -	Compliant with law today
Carbon (CO_2 Emissions)			Unknown at this time			Unknown at this time
Wastewater Discharge Standards			Unknown at this time			Unknown at this time

* Source is 2012 S&L ECP study - Reported in 2011 $ at +/- 20%

BIG RIVERS ELECTRIC CORPORATION

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

Response to Commission Staff's Second Request for Information dated February 14, 2013

February 28, 2013

Item 22) ***Refer to the Berry Testimony, pages 26-29, regarding the incremental transmission costs resulting from being a member of MISO. Explain in detail any known or potential incremental costs that would be charged to Big Rivers by MISO if Century continues to operate but is not a retail customer of Kenergy Corp.***

Response) Due to Century's exit, Big Rivers will be required to increase its Open Access Transmission Tariff ("OATT") per-unit rates to recover the operating and maintenance expense that were previously paid by Century. How Century structures its purchases will determine the amount of transmission cost that will be recovered by Big Rivers. If Century enters into a bilateral contract with a third party and the bilateral contract does not have a designated generator, then only one-half of the cost paid by Century will be paid to Big Rivers. Additionally, if MISO implements a transmission upgrade project to eliminate the must run condition of the Coleman plant, then Big Rivers will be required to pay a portion of that upgrade based on its load. Preliminary estimates indicate Big Rivers would be responsible for approximately 60% of the cost to install the upgrades. If Century were to cease operations after the upgrade project begins, then Big Rivers would still be obligated to pay certain cost associated with the transmission upgrade project.

Since Century would still be load connected to the Big Rivers transmission system, Century will be responsible for paying all normal transmission service costs under the MISO Tariff. Century would be served either under Schedule 7 Long-Term and Short-Term Firm Point-to-Point Service or under Schedule 9 Network Integration Transmission Service. Century would be subject to pay MISO administrative costs in accordance with Schedule 10.

Century would also be required to pay for all required Ancillary Services as described in MISO Schedules 1 through 6 which includes: Scheduling, System Control and Redispatch; Reactive Supply and Voltage Control; Regulation and Frequency Response; Energy Imbalance; Operating Reserve-Spinning; and Operating Reserve-Supplemental.

In addition, Century would be subject to pay Schedule 26 charges related to network upgrades identified in the MISO transmission expansion plan and Schedule 26A charges related to MISO Multi-Value Projects which apply to Century's transmission service reservation.

Witness) Robert W. Berry

Item 23) ***Refer to the Direct Testimony of David C. Crockett ("Crockett Testimony") at pages 5-7.***

a. Provide Big Rivers' most recent three-year construction work plan.

b. Provide, in comparative form, for the years 2008 through 2012 and the forecast period, the fixed department expenses for transmission.

Response)

a. Due to its file size, Big Rivers' most recent three-year construction work plan (2013-2015) is being provided on the CD accompanying these responses.

b. Big Rivers does not have the information requested for years prior to and including 2009. The System Operations department's 2010 through 2012 fixed departmental expenses plus the fixed departmental expenses for the forecast test period are attached to this response.

Witness) David G. Crockett

Big Rivers Electric Corporation
Case No. 2012-00535

Attachment to Response for PSC 2-23(b)
System Operations Fixed Departmental Expenses

ORG	Description	2010	2011	2012
0014	VP Transmission	$1,721,607	$393,615	$438,743
0355	Real Estate	$16,835	$8,437	$9,710
0370	Engineering	$371,742	$250,864	$337,532
0405	Energy Control	$231,401	$70,480	$52,334
0420	ET&S	$2,060,321	$2,013,505	$1,924,903
	Total	**$4,401,906**	**$2,736,901**	**$2,763,222**

BIG RIVERS ELECTRIC CORPORATION

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

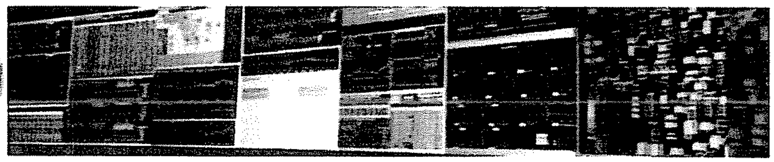
Response to Commission Staff's Second Request for Information dated February 14, 2013

February 28, 2013

Item 24) ***Refer to the Crocket Testimony, at page 10, lines 11-19. Provide the Midwest ISO transmission export study.***

Response) A redacted copy of the Midwest ISO transmission export study entitled "First Contingency Incremental Transfer Capability Study" and dated July 6, 2011 is provided as an attachment to this response. Big Rivers does not have permission from the Midwest ISO to release the unredacted report.

Witness) David G. Crockett

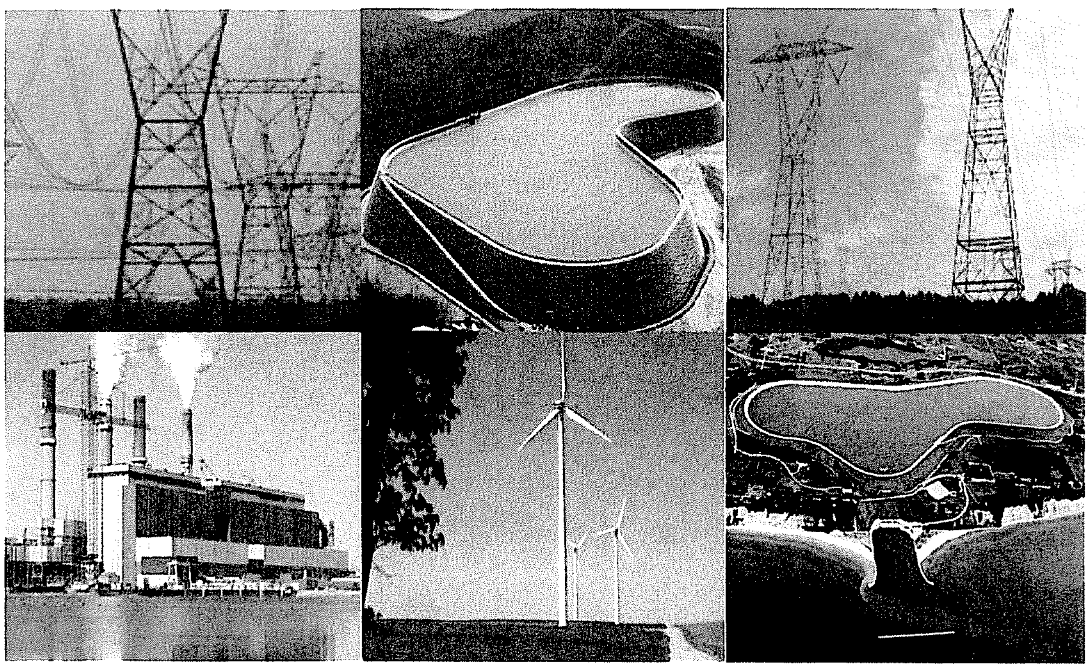


Contains Critical Energy Infrastructure Information - Do Not Release

First Contingency Incremental Transfer Capability Study for Big Rivers Electric Corporation [BREC]

July 6, 2011

By
David A. Mendonsa, P.E.



First Contingency Incremental Transfer Capability Study for Big Rivers Electric Corporation [BREC]

A First Contingency Incremental Transfer Capability (FCITC) Study was conducted for Big Rivers Electric Corporation to access transfer capability five years from now, in year 2016. FCITC measures the maximum increase in power transfer that can take place between a **source system** and a **sink system** without violating thermal ratings of transmission lines or transformers. The MISO MTEP11, 2016 Summer Peak model with a security constraint economic dispatch, served as the case for these studies. Four FCITC transfers were studied, including:

1) Southern Indiana to BREC
2) BREC to Southern Indiana
3) TVA to BREC
4) BREC to TVA

The FCITC results for the four transfers are provided. The first contingency causing thermal violations, the associated overloaded transmission system element and the definition of the transfers are also provided.

1) Southern Indiana to BREC Transfer

A high transfer from Southern Indiana to BREC was analyzed. The observed transfer capability of 1568 MWs is limited by [redacted] The results of this transfer study are summarized below in Table 1. Loss of [redacted] will initiate implementation of operating guide [redacted]. The provisions of this operating guide to mitigate [redacted] This operating guide may also restrict the Southern Indiana to BREC transfer capability to 1568 MWs.

Transfer	Southern Indiana to BREC
FCITC	1568 MWs
Limiting Element	[redacted]
TDF (%) on the Limiting Element	8.25%
FCITC Flow on the Limiting Element	129.4 MWs
Base Flow on the Limiting Element	46.7 MWs
Limiting Flow on the Limiting Element	176 MWs
Rating of the Limiting Element	176 MWs
Contingency Description	[redacted]

Table 1. – Southern Indiana to BREC Transfer

The definition of the Southern Indiana to BREC transfer is provided below:

> Source of Transfer: SIndiana_Export; Scaling up of generation, including offline generation, in Area 207 – HE, Area 208 – Duke Energy Indiana, Area 212 – Duke Energy Ohio and Kentucky and Area 216 – IP&L
>
> Sink of Transfer: BREC_Import; Scaling down of BREC generation

2) BREC to Southern Indiana Transfer

A high transfer from BREC to Southern Indiana was analyzed. The observed transfer capability of 1210 MWs is limited by [redacted] due to Category A "Base Case" thermal overload at this transfer level. The results of this transfer study are summarized below in Table 2. The second FCITC limitation is 1768 MWs. The [redacted] is the limiting element due to Category A "Base Case" thermal overload at the 1768 MW transfer level.

Transfer	**BREC to Southern Indiana**
FCITC	1210 MW
Limiting Element	[redacted]
TDF (%) on the Limiting Element	20.37%
FCITC Flow on the Limiting Element	246.4 MW
Base Flow on the Limiting Element	88.6 MW
Limiting Flow on the Limiting Element	335 MW
Rating of the Limiting Element	335 MW
Contingency Description	Base Case

Table 2. – BREC to Southern Indiana Transfer

The definition of the BREC to Southern Indiana transfer is provided below:

Source of Transfer: BREC_Export; Scaling up of generation in Area 314 – BREC

Sink of Transfer: Indiana_Import; Scaling down of generation, including offline generation, in Area 207 – HE, Area 208 – Duke energy Indiana, Area 210 SIGE, Area 212 – Duke Energy Ohio & Kentucky, Area 216 – IP&L and Area 217 - NIPS

3) TVA to BREC Transfer

A high transfer from TVA to BREC was analyzed. The observed transfer capability of 1870 MWs is limited by [redacted] with the Category B contingency loss of [redacted]. The results of this transfer study are summarized below in Table 3. As the transfer from TVA is increasing and the BREC generation is diminishing, the majority of the increasing transfer will flow from TVA. However, as transfer flow from TVA is increasing, load on the [redacted]. At the above transfer level of 1870 MWs, a Category B contingency loss of [redacted] will result in the thermal overloading of [redacted].

Loss of [redacted] will initiate implementation of operating guide [redacted]. The provisions of this operating guide to mitigate potential low voltage and thermal overloads [redacted]. This operating guide may also restrict the TVA to BREC transfer capability to 1870 MWs.

Transfer	TVA to BREC
FCITC	1870 MW
Limiting Element	[redacted]
TDF (%) on the Limiting Element	6.92%
FCITC Flow on the Limiting Element	129.3 MW
Base Flow on the Limiting Element	46.7 MW
Limiting Flow on the Limiting Element	176 MW
Rating of the Limiting Element	176 MW
Contingency Description	[redacted]

Table 3. – TVA to BREC Transfer

The definition of the TVA to BREC transfer is provided below:

Source of Transfer: TVA_Export; Scaling up of specific generating units in Area 347 – TVA

Sink of Transfer: BREC_Import; Scaling down of BREC generation

4) BREC to TVA Transfer

A high transfer from BREC to TVA was analyzed. The observed transfer capability of 1263 MWs is limited by [redacted] due to Category A "Base Case" thermal overload at this transfer level. The results of this transfer study are summarized below in Table 4. The second FCITC limitation is 1752 MW. The [redacted]

[redacted] is the limiting element due to Category A "Base Case" thermal overload at the 1752 MW transfer level

Transfer	BREC to TVA
FCITC	1263 MW
Limiting Element	[redacted]
TDF (%) on the Limiting Element	19.52%
FCITC Flow on the Limiting Element	246.4 MW
Base Flow on the Limiting Element	88.6 MW
Limiting Flow on the Limiting Element	335 MW
Rating of the Limiting Element	335 MW
Contingency Description	Base Case

Table 4. – BREC to TVA Transfer

The definition of the BREC to TVA transfer is provided below:

Source of Transfer: BREC_Export; Scaling up of generation in Area 314 – BREC

Sink of Transfer: TVA_Import; Scaling down of generation in Area 347 – TVA

CONCLUSIONS:

BREC import of power from either Southern Indiana generation or TVA is limited by [redacted] with the Category B contingency loss o[redacted]. Loss of service of [redacted] will require operating guide [redacted] to be implemented to mitigate potential low voltage and thermal overloads in [redacted]. The operating guide may limit BREC import of power.

Export of power from BREC to either Southern Indiana or TVA is limited by the [redacted]. The re-dispatch of area generation, particularly at [redacted], may reduce potential emergency loading on this line and allow additional power to be exported.

Item 25) ***Refer to the Speed Testimony at page 15. Provide a breakdown of the estimated rate-case expenses of approximately $1.6 million.***

Response) Please see the attachment provided in response to PSC 1-54(b).

Witness) Travis A. Siewert

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

**Response to Commission Staff's Second Request for Information
dated February 14, 2013**

February 28, 2013

Item 26) ***Refer to the Speed Testimony at page 18, lines 21-22. Provide the Big Rivers 2014-2016 financial plans which received board approval November 16, 2012.***

Response) A copy of the presentation submitted for board approval on November 16, 2012 is provided as an attachment to this request. The presentation includes Big Rivers' 2014-2016 financial plans.

Witness) DeAnna M. Speed

Big Rivers Electric Corporation

2013 Budget
2014-2016 Financial Plan

Date Presented: November 16, 2012

Big Rivers ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

North Star

Cost per kWh (A divided by B)

A = Total Cost of Electric Service Minus Non-Member Revenues

B = Smelter and Non-Smelter Member kWh

North Star per Financial Plan

North Star per October 2008 Unwind Model

2013: [redacted]
2014:
2015:
2016:

[redacted]

Mission, Vision and Values

Mission

- Big Rivers will safely deliver low cost, reliable wholesale power, and the cost-effective shared services desired by our Members

Vision

- Big Rivers will be viewed as one of the top G&Ts in the country, and will provide the services our Members desire in meeting future challenges

Values

- Safety
- Integrity
- Excellence
- Member and Community Service
- Respect for the Employee
- Teamwork
- Environmentally Conscious

Noteworthy Assumptions ($ in Thousands)

All $ in 000s

1 The Member (including Smelter) base rate revenue is based on the PSC Order received in November 2011. General Rate base wholesale revenue increase of 29% for Rurals, 18% for Large Industrials and 16% for the Smelter is effective August 21, 2013. One hundred percent of the subsidy between the Rurals and other rate classes has been removed. (No assumption related to outcome of 2012 Rehearing on 2011 Rate Case.)

2 The Smelter(s) are at the ceiling of the TIER Adjustment Charge in 2013 ($2.95). Century ceases operation effective August 20, 2013, per their notification letter. Alcan remains under existing contract structure. Alcan is slightly below the ceiling of their TIER Adjustment Charge in 2014 ($2.94), below the ceiling in 2015 ($2.37), and at the ceiling in 2016 ($3.55).

3 Wilson Station is layed up beginning August 21, 2013. Labor reduction is effective December 1, 2013.

4 Off-System sales:

	2013	2014	2015	2016
$/MWh (average)	[redacted]	[redacted]	[redacted]	[redacted]
MWh	[redacted]	[redacted]	[redacted]	[redacted]

5 Total MWh sales:

	2013	2014	2015	2016
MWh	[redacted]	[redacted]	[redacted]	[redacted]

6 Big Rivers' MWh net generation:

	2013	2014	2015	2016
MWh	[redacted]	[redacted]	[redacted]	[redacted]

Noteworthy Assumptions ($ in Thousands)

continued

7 Market purchases:

	2013	2014	2015	2016
$/MWh (average)	[redacted]			
MWh				

8 Economic Reserve depletes and Rural Economic Reserve (RER) starts in 2015. RER depletes in 2018.

9 Environmental Compliance Plan (ECP) assumes HAPS/MATS are viable.

10 Environmental Surcharge mechanism changes as approved by the KPSC in the ECP Case is effective (includes ECP expense amortization beginning in 2013 and depreciation, property tax & insurance beginning in 2014).

11 HMP&L Excess Energy calculation does not consider the ruling from the arbitration.

12 2.25% wage increase for non-bargaining employees in January, for Production bargaining employees in September and for Transmission bargaining employees in October each year 2013-2015; 2% for all employees in 2016.

13 Headcount of 627 employees January-November 2013, 535 in December 2013 due to lay up of Wilson. Year end headcount for 2014-2016 is 536. Labor dollars include "churn" of 16 employees in 2013 and 14 employees each year 2014-2016. (Average number of employees in 2012 is 611).

14 Severance package cost of $4,600 related to the Wilson lay-up is deferred and amortized over a 60 month period for both rate recovery and accounting purposes beginning 9/1/13.

15 City's MW share of Station Two is based on the unapproved Capacity Reservation and Allocation letter received from HMP&L in April: 115 MW through 5/31/13, 120 MW through 5/31/14, 125 MW for the remaining planning period.

Noteworthy Assumptions ($ in Thousands)

continued

16 2012 Depreciation Study preliminary rates are reflected.

17 Capital Expenditures for 2013-2016, excluding City's share of Station Two and including capitalized interest:

	2013	2014	2015	2016
Env. Compliance	32,198	29,301	0	0
Base CAPEX	47,715	47,305	48,111	38,370
Total $	79,913	76,606	48,111	38,370

18 Refinance the $58.8m PC Bonds in March 2013, at 6.0% and a level debt service.

19 ECP borrowing at 3.0% with draws matched to spending.

20 MISO administrative fees:

	2013	2014	2015	2016
$	4,026	2,426	2,438	2,464

No assumption for HMP&L's share of MISO expenses each year.

21 Rate case expenditures of $1,586 are deferred and amortized over a 36 month period for both rate and accounting purposes (amortization begins 9/1/13).

Outage Schedule – 2013-2014

Start	End	Number of Days	Unit/Outage

2013

[redacted]			
	Total	[redacted]	

2014

[redacted]			
	Total	[redacted]	

Outage Schedule – 2015-2016

Start	End	Number of Days	Unit/Outage
	2015		
[redacted]			
	Total	[redacted]	
	2016		
[redacted]			
	Total	[redacted]	

Planned Outage and Routine Fixed Departmental Expense (FDE)

	2010 Actual	2011 Actual	2012 Budget	2012 Forecast	2013 Budget	Financial Plan 2014	2015	2016
Planned Outage	7,987	4,724	22,664	7,953	[redacted]			
Routine	33,725	36,443	37,705	33,083				
Total Production FDE	41,712	41,167	60,369	41,036				

BIG RIVERS ELECTRIC CORPORATION
STATEMENT OF OPERATIONS

in $000s

	2012 Budget	2012 Forecast (8+4)	2013 Budget	2014 Financial Plan	2015 Financial Plan	2016 Financial Plan
ELECTRIC ENERGY REVENUES	614,725	556,113	[redacted]	[redacted]	[redacted]	[redacted]
OTHER OPERATING REVENUE AND INCOME	4,012	4,861	[redacted]	[redacted]	[redacted]	[redacted]
TOTAL OPER REVENUES & PATRONAGE CAPITAL	618,737	560,974	[redacted]	[redacted]	[redacted]	[redacted]
OPERATION EXPENSE-PRODUCTION-EXCL FUEL	54,962	49,286	[redacted]	[redacted]	[redacted]	[redacted]
OPERATION EXPENSE-PRODUCTION-FUEL	240,841	222,227	[redacted]	[redacted]	[redacted]	[redacted]
OPERATION EXPENSE-OTHER POWER SUPPLY	126,165	109,264	[redacted]	[redacted]	[redacted]	[redacted]
OPERATION EXPENSE-TRANSMISSION	10,723	9,798	[redacted]	[redacted]	[redacted]	[redacted]
OPERATION EXPENSE-RTO/ISO	2,471	2,261	[redacted]	[redacted]	[redacted]	[redacted]
CONSUMER SERVICE & INFORMATIONAL EXPENSE	724	554	[redacted]	[redacted]	[redacted]	[redacted]
OPERATION EXPENSE-SALES	1,102	854	[redacted]	[redacted]	[redacted]	[redacted]
OPERATION EXPENSE-ADMINISTRATIVE & GENERAL	25,926	28,132	[redacted]	[redacted]	[redacted]	[redacted]
TOTAL OPERATION EXPENSE	462,914	422,376	[redacted]	[redacted]	[redacted]	[redacted]
MAINTENANCE EXPENSE-PRODUCTION	58,890	40,914	[redacted]	[redacted]	[redacted]	[redacted]
MAINTENANCE EXPENSE-TRANSMISSION	3,933	4,559	[redacted]	[redacted]	[redacted]	[redacted]
MAINTENANCE EXPENSE-GENERAL PLANT	102	155	[redacted]	[redacted]	[redacted]	[redacted]
TOTAL MAINTENANCE EXPENSE	62,925	45,628	[redacted]	[redacted]	[redacted]	[redacted]
DEPRECIATION & AMORTIZATION EXPENSE	41,911	41,272	42,314	44,908	46,847	47,799
TAXES	1	4	1	1	1	1
INTEREST ON LONG-TERM DEBT	44,647	45,028	46,304	47,162	47,088	46,729
INTEREST CHARGED TO CONSTRUCTION-CREDIT	(678)	(789)	(772)	(2,102)	(499)	(367)
OTHER INTEREST EXPENSE	0	55	0	0	0	0
OTHER DEDUCTIONS	416	261	577	591	596	444
TOTAL COST OF ELECTRIC SERVICE	612,136	553,835	[redacted]	[redacted]	[redacted]	[redacted]
OPERATING MARGINS	6,601	7,139	[redacted]	[redacted]	[redacted]	[redacted]
INTEREST INCOME	62	889	2,019	1,950	1,881	1,815
ALLOWANCE FOR FUNDS USED DURING CONST	0	0	0	0	0	0
OTHER NON-OPERATING INCOME - NET	0	0	0	0	0	0
OTHER CAPITAL CREDITS & PAT DIVIDENDS	33	59	1,271	2,706	2,628	2,544
EXTRAORDINARY ITEMS	0	0	0	0	0	0
NET PATRONAGE CAPITAL OR MARGINS	6,696	8,087	[redacted]	[redacted]	[redacted]	[redacted]
North Star	0.050925	0.047904	[redacted]	[redacted]	[redacted]	[redacted]
TIER	1.15	1.18	[redacted]	[redacted]	[redacted]	[redacted]

Budget does not reflect incentive pay estimate.

BIG RIVERS ELECTRIC CORPORATION
STATEMENT OF OPERATIONS

in $000s

	2013 Budget													2012 Forecast (8+4)
	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL	TOTAL
ELECTRIC ENERGY REVENUES	[redacted]													556,113
OTHER OPERATING REVENUE AND INCOME														4,861
TOTAL OPER REVENUES & PATRONAGE CAPITAL														560,974
OPERATION EXPENSE-PRODUCTION-EXCL FUEL														49,286
OPERATION EXPENSE-PRODUCTION-FUEL														222,227
OPERATION EXPENSE-OTHER POWER SUPPLY														109,264
OPERATION EXPENSE-TRANSMISSION														9,798
OPERATION EXPENSE-RTO/ISO														2,261
CONSUMER SERVICE & INFORMATIONAL EXPENSE														554
OPERATION EXPENSE-SALES														854
OPERATION EXPENSE-ADMINISTRATIVE & GENERAL														28,132
TOTAL OPERATION EXPENSE														422,376
MAINTENANCE EXPENSE-PRODUCTION														40,914
MAINTENANCE EXPENSE-TRANSMISSION														4,559
MAINTENANCE EXPENSE-GENERAL PLANT														155
TOTAL MAINTENANCE EXPENSE														45,628
DEPRECIATION & AMORTIZATION EXPENSE	3,440	3,442	3,446	3,452	3,466	3,479	3,487	3,493	3,642	3,647	3,658	3,662	42,314	41,272
TAXES	0	0	0	1	0	0	0	0	0	0	0	0	1	4
INTEREST ON LONG-TERM DEBT	3,802	3,494	3,929	3,837	3,944	3,802	3,936	3,936	3,821	3,973	3,865	3,965	46,304	45,028
INTEREST CHARGED TO CONSTRUCTION-CREDIT	(2)	(6)	(22)	(46)	(40)	(60)	(80)	(41)	(60)	(103)	(135)	(177)	(772)	(789)
OTHER INTEREST EXPENSE	0	0	0	0	0	0	0	0	0	0	0	0	0	55
OTHER DEDUCTIONS	46	38	48	46	45	64	44	44	43	47	46	66	577	261
TOTAL COST OF ELECTRIC SERVICE	[redacted]													553,835
OPERATING MARGINS														7,139
INTEREST INCOME	171	170	170	169	169	168	168	168	168	168	166	164	2,019	889
ALLOWANCE FOR FUNDS USED DURING CONST	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OTHER NON-OPERATING INCOME - NET	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OTHER CAPITAL CREDITS & PAT DIVIDENDS	0	0	1,238	25	0	0	0	8	0	0	0	0	1,271	59
EXTRAORDINARY ITEMS	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NET PATRONAGE CAPITAL OR MARGINS	[redacted]													8,087

Cash Position * (in Thousands of $)

	Budget	Financial Plan		
	2013	2014	2015	2016
Beginning Balance	101,423	82,849	80,952	82,870
Cash Receipts	548,617	492,318	513,575	529,089
Cash Disbursements	(537,518)	(460,633)	(450,328)	(457,648)
Debt Service	(29,673)	(33,582)	(61,329)	(62,784)
Ending Balance	82,849	80,952	82,870	91,527

*** General Fund and Temporary Investments**

Electric Energy Revenue – 2013

($ in Thousands)

	2013			2012 Budget	2012 Forecast (8+4)
	MWH	$	$/MWH	$/MWH	$/MWH
MEMBER REVENUE:					
GROSS:					
Rurals	2,409,829	143,329	59.48	53.10	50.57
Industrials	943,027	46,238	49.03	45.89	43.18
	3,352,856	189,567	56.54	51.02	48.40
LESS MRSM:					
Rurals	2,409,829	19,648	8.15	8.74	6.06
Industrials	943,027	7,131	7.56	8.64	6.10
	3,352,856	26,779	7.99	8.71	6.07
NET MEMBER REVENUE:					
Rurals	2,409,829	123,681	51.32	44.36	44.51
Industrials	943,027	39,107	41.47	37.25	37.08
	3,352,856	162,788	48.55	42.31	42.34
SMELTER REVENUE:					
Smelters	5,820,541	302,822	52.03	51.80	48.77
MARKET REVENUE:					
Market Sales	[redacted]				
ELECTRIC ENERGY REVENUE					

Electric Energy Revenue – 2014

($ in Thousands)

	2014			2013
	MWH	$	$/MWH	$/MWH
MEMBER REVENUE:				
GROSS:				
Rurals	2,448,796	181,796	74.24	59.48
Industrials	943,699	55,090	58.38	49.03
	3,392,495	236,886	69.83	56.54
LESS MRSM:				
Rurals	2,448,796	24,621	10.05	8.15
Industrials	943,699	8,671	9.19	7.56
	3,392,495	33,292	9.81	7.99
NET MEMBER REVENUE:				
Rurals	2,448,796	157,175	64.18	51.32
Industrials	943,699	46,419	49.19	41.47
	3,392,495	203,594	60.01	48.55
SMELTER REVENUE:				
Smelter(s)	3,159,206	191,192	60.52	52.03
MARKET REVENUE:				
Market Sales	[redacted]			
ELECTRIC ENERGY REVENUE	[redacted]			

Electric Energy Revenue – 2015

($ in Thousands)

	2015			2014
	MWH	$	$/MWH	$/MWH
MEMBER REVENUE:				
GROSS:				
Rurals	2,479,657	189,906	76.59	74.24
Industrials	943,699	57,150	60.56	58.38
	3,423,356	247,056	72.17	69.83
LESS MRSM:				
Rurals	2,479,657	27,629	11.14	10.05
Industrials	943,699	5,911	6.26	9.19
	3,423,356	33,540	9.80	9.81
NET MEMBER REVENUE:				
Rurals	2,479,657	162,277	65.44	64.18
Industrials	943,699	51,239	54.30	49.19
	3,423,356	213,516	62.37	60.01
SMELTER REVENUE:				
Smelter	3,159,206	199,689	63.21	60.52
MARKET REVENUE:				
Market Sales	[redacted]			
ELECTRIC ENERGY REVENUE				

Electric Energy Revenue – 2016

($ in Thousands)

	2016 MWH	2016 $	2016 $/MWH	2015 $/MWH
MEMBER REVENUE:				
GROSS:				
Rurals	2,519,437	198,316	78.71	76.59
Industrials	944,107	59,181	62.68	60.56
	3,463,544	257,497	74.34	72.17
LESS MRSM:				
Rurals	2,519,437	30,064	11.93	11.14
Industrials	944,107	0	0.00	6.26
	3,463,544	30,064	8.68	9.80
NET MEMBER REVENUE:				
Rurals	2,519,437	168,252	66.78	65.44
Industrials	944,107	59,181	62.68	54.30
	3,463,544	227,433	65.66	62.37
SMELTER REVENUE:				
Smelter	3,167,862	205,773	64.96	63.21
MARKET REVENUE:				
Market Sales	[redacted]			
ELECTRIC ENERGY REVENUE				

Production - Variable Costs – 2013

(in Thousands of $)

	2013 Budget							2012 (8+4)
	Wilson	Green	Coleman	Station Two	Reid Steam	Reid CT	Total	Total
Generation MWh (Net)	[redacted]							[redacted]
Heat Rate								
MMbtu Burn (Coal)								111,248,380
$/Mmbtu (Coal)								2.18
Total Fuel Cost								246,978
Fuel Cost (Cents / kWh)								2.40
Non-Fuel VO Cost								[redacted]
Non-Fuel VO (Cents / kWh)								
Total Variable Cost (Fuel & Non-Fuel)								
Total Variable (Cents / kWh)								

*Station Two Variable Costs are included in Other Power Supply Expense as Purchased Power.

Production - Variable Costs – 2014

(in Thousands of $)

	2014 Financial Plan							2013 Budget
	Wilson	Green	Coleman	Station Two	Reid Steam	Reid CT	Total	Total
Generation MWh (Net)	[redacted]							[redacted]
Heat Rate								
MMbtu Burn (Coal)								
$/Mmbtu (Coal)								
Total Fuel Cost								
Fuel Cost (Cents / kWh)								
Non-Fuel VO Cost								
Non-Fuel VO (Cents / kWh)								
Total Variable Cost (Fuel & Non-Fuel)								
Total Variable (Cents / kWh)								

*Station Two Variable Costs are included in Other Power Supply Expense as Purchased Power.

Production - Variable Costs – 2015

(in Thousands of $)

	2015 Financial Plan							2014 Financial Plan
	Wilson	Green	Coleman	Station Two	Reid Steam	Reid CT	Total	Total
Generation MWh (Net)	[redacted]							
Heat Rate								
MMbtu Burn (Coal)								
$/Mmbtu (Coal)								
Total Fuel Cost								
Fuel Cost (Cents / kWh)								
Non-Fuel VO Cost								
Non-Fuel VO (Cents / kWh)								
Total Variable Cost (Fuel & Non-Fuel)								
Total Variable (Cents / kWh)								

*Station Two Variable Costs are included in Other Power Supply Expense as Purchased Power.

Production - Variable Costs – 2016

(in Thousands of $)

	2016 Financial Plan							2015 Financial Plan
	Wilson	Green	Coleman	Station Two	Reid Steam	Reid CT	Total	Total
Generation MWh (Net)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Heat Rate	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
MMbtu Burn (Coal)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
$/Mmbtu (Coal)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Fuel Cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fuel Cost (Cents / kWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non-Fuel VO Cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non-Fuel VO (Cents / kWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Variable Cost (Fuel & Non-Fuel)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Variable (Cents / kWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

*Station Two Variable Costs are included in Other Power Supply Expense as Purchased Power.

Operation Expense-Other Power Supply

(in Thousands of $)

	2012 Budget	2012 Forecast (8+4)	2013 Budget	2014	2015	2016
				Financial Plan		
PURCHASED POWER:						
SEPA	9,615	8,615	[redacted]	[redacted]	[redacted]	[redacted]
HMP&L Station Two Excess Energy	549	301	[redacted]	[redacted]	[redacted]	[redacted]
Market Purchases	45,186	36,271	[redacted]	[redacted]	[redacted]	[redacted]
Member Passthrough	(3,695)	(2,483)	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal	51,655	42,704	[redacted]	[redacted]	[redacted]	[redacted]
OTHER POWER SUPPLY COSTS:						
HMP&L Station Two						
Depreciation	2,598	3,183	3,341	3,462	3,611	3,696
Labor	7,720	8,038	7,571	7,278	7,361	7,540
Fuel	40,585	34,057	[redacted]	[redacted]	[redacted]	[redacted]
Variable Operation Expense	6,306	5,072	[redacted]	[redacted]	[redacted]	[redacted]
Property Insurance	382	382	399	440	461	485
Property Tax	253	177	190	191	193	194
O&M Non-Labor	12,416	11,743	[redacted]	[redacted]	[redacted]	[redacted]
Power Supply Reservation	4,250	3,908	[redacted]	[redacted]	[redacted]	[redacted]
Subtotal	74,510	66,560	[redacted]	[redacted]	[redacted]	[redacted]
Total Operation Expense - Other Power Supply	126,165	109,264	[redacted]	[redacted]	[redacted]	[redacted]

Labor and Labor Overheads ($ in Thousands)

	Budget				Financial Plan					
	2012		2013		2014		2015		2016	
	$	Headcount	$	Headcount	$	Headcount	$	Headcount	$	Headcount
Production	46,015	441	45,775	437	36,203	351	36,996	351	37,951	351
Transmission	3,083	34	3,286	33	3,234	33	3,321	33	3,410	33
Support	19,583	158	19,737	157	18,900	152	19,476	152	19,932	152
Total*	68,681	633	68,798	627	58,337	536	59,793	536	61,293	536

* Dollars reflect Big Rivers' share of labor/labor overhead expense.
Headcount in 2013 reflects staffing prior to Wilson lay-up. Staffing at 12/31/13 will be 535.

"Churn" of 16 employees in 2013 and 14 employees in all other years is assumed in the labor dollar calculations.

Capital Expenditures * (in Thousands of $)

	2012 Budget	2012 Forecast (8+4)	2013 Budget	Financial Plan 2014	Financial Plan 2015	Financial Plan 2016
Production	52,359	27,756	[redacted]	[redacted]	[redacted]	[redacted]
Transmission	12,459	9,270	[redacted]	[redacted]	[redacted]	[redacted]
Environmental Compliance Projects	14,112	479	[redacted]	[redacted]	[redacted]	[redacted]
Administration	2,259	1,657	2,644	554	238	232
IT	2,116	2,046	2,675	1,640	2,044	1,032
Total Capital Expenditures	**83,305**	**41,208**	**79,913**	**76,606**	**48,111**	**38,370**

*Big Rivers' share, includes capitalized interest.

Item 27) ***Refer to the Direct Testimony of Lindsay N. Barron at page 8, line 19, through page 9, line 10.***

a. Provide Big Rivers' demand and energy load forecast values for calendar year 2012 in the same format as used in Exhibit Barron-3 for 2013 and 2014.

b. Provide Big Rivers' actual Rural and Large Industrial energy sales for calendar year 2012.

Response)

a. Please see the attachments to this response.

b.	Rural Sales	Energy	2,321,477,598 kWh
		Demand	5,141,696 kW
	Industrial Sales	Energy	961,298,194 kWh
		Demand	1,708,506 kW

Witness) Lindsay N. Barron

Big Rivers Electric Corporation
Case No. 2012-00535

Attachment 1 to Response for PSC 2-27a
2012 Demand Budget

	BILLING DEMAND (MW) - 2012					
	January 2012	February 2012	March 2012	April 2012	May 2012	June 2012
KENERGY	263.0	237.0	208.0	166.0	192.0	241.0
JACKSON PURCHASE	146.0	130.0	114.0	88.0	110.0	140.0
MEADE COUNTY	129.0	114.0	96.0	74.0	72.0	90.0
TOTAL MEMBER RURAL DEMAND	538.0	481.0	418.0	328.0	374.0	471.0
ACCURIDE	5.2	5.3	5.4	5.4	5.5	5.4
ALCOA	0.1	0.2	0.2	0.2	0.2	0.2
ALERIS	28.2	27.4	27.2	26.6	26.7	26.6
ALLIED (STEMPORT)	7.0	7.2	6.9	6.9	6.4	6.9
ARMSTRONG DOCK	5.4	5.2	4.7	4.3	4.2	4.1
ARMSTRONG EQUALITY	3.0	2.7	3.1	3.3	3.1	3.1
ARMSTRONG LEWIS CREEK	0.5	0.5	0.5	0.5	0.5	0.5
ARMSTRONG MIDWAY	3.7	3.7	3.8	3.5	3.3	3.5
ARVIN ROLL COATER	3.8	3.8	3.8	3.8	3.8	3.8
DOMTAR	25.0	25.0	25.0	25.0	25.0	25.0
DOTIKI # 3	0.8	0.8	0.8	0.8	0.8	0.8
HOPKINS CO. COAL	0.3	0.5	0.4	0.4	0.4	0.4
KB ALLOY	2.0	2.0	2.0	2.0	2.0	2.0
KIMBERLY CLARK	36.3	36.3	36.5	36.8	36.6	36.8
KMMC, Inc./P&M/Cochise	0.3	0.2	0.2	0.2	0.1	0.1
PATRIOT COAL	5.2	5.3	4.9	5.0	4.7	4.6
Shell Oil JP Industrials	3.4	3.4	3.4	3.4	3.4	3.4
SOUTHWIRE COMPANY	6.7	6.9	6.6	6.9	6.7	6.9
TYSON	9.1	9.0	9.1	10.0	10.5	10.0
VALLEY	2.0	2.0	2.0	1.8	2.0	1.9
TOTAL MEMBER NCP IND'L DEMAND	147.9	147.2	146.4	146.7	145.8	145.9
ALCAN	368.0	368.0	368.0	368.0	368.0	368.0
CENTURY	482.0	482.0	482.0	482.0	482.0	482.0
TOTAL	1,535.9	1,478.2	1,414.4	1,324.7	1,369.8	1,466.9

Big Rivers Electric Corporation
Case No. 2012-00535

Attachment 1 to Response for PSC 2-27a
2012 Demand Budget

	BILLING DEMAND (MW) - 2012						
	July 2012	August 2012	September 2012	October 2012	November 2012	December 2012	TOTAL
KENERGY	251.0	270.0	219.0	170.0	192.0	242.0	2,651.0
JACKSON PURCHASE	147.0	159.0	116.0	96.0	104.0	135.0	1,485.0
MEADE COUNTY	94.0	103.0	80.0	70.0	80.0	116.0	1,118.0
TOTAL MEMBER RURAL DEMAND	492.0	532.0	415.0	336.0	376.0	493.0	5,254.0
ACCURIDE	5.5	5.4	5.5	5.5	5.4	5.5	65.1
ALCOA	0.2	0.2	0.2	0.2	0.2	0.2	2.1
ALERIS	26.7	26.6	26.7	26.7	26.6	26.7	322.5
ALLIED (STEMPORT)	6.4	6.9	6.4	6.4	6.9	6.4	80.6
ARMSTRONG DOCK	4.2	3.8	2.1	4.0	4.4	4.8	51.2
ARMSTRONG EQUALITY	3.2	3.1	3.2	3.2	3.2	3.2	37.2
ARMSTRONG LEWIS CREEK	0.5	0.5	0.5	0.5	0.5	0.5	6.0
ARMSTRONG MIDWAY	3.3	3.5	3.3	3.3	3.5	3.3	41.6
ARVIN ROLL COATER	3.8	3.8	3.8	3.8	3.8	3.8	45.0
DOMTAR	25.0	25.0	25.0	25.0	25.0	25.0	300.0
DOTIKI # 3	0.8	0.8	0.8	0.8	0.8	0.8	9.6
HOPKINS CO. COAL	0.4	0.4	0.4	0.4	0.4	0.4	4.6
KB ALLOY	2.0	2.0	2.0	2.0	2.0	2.0	24.0
KIMBERLY CLARK	36.6	36.8	36.6	36.6	36.8	36.6	439.4
KMMC, Inc./P&M/Cochise	0.1	0.1	0.1	0.1	0.1	0.1	1.6
PATRIOT COAL	4.5	5.0	5.0	4.5	4.5	4.5	57.7
Shell Oil JP Industrials	3.4	3.4	3.4	3.4	3.4	3.4	40.8
SOUTHWIRE COMPANY	6.7	6.9	6.4	7.1	6.7	6.5	81.0
TYSON	10.5	10.0	10.5	10.5	10.0	10.5	119.6
VALLEY	1.9	1.9	1.9	1.9	1.8	1.8	22.9
TOTAL MEMBER NCP IND'L DEMAND	145.5	145.9	143.7	145.8	145.7	145.9	1,752.4
ALCAN	368.0	368.0	368.0	368.0	368.0	368.0	4,416.0
CENTURY	482.0	482.0	-	-	-	-	3,856.0
TOTAL	1,487.5	1,527.9	926.7	849.8	889.7	1,006.9	15,278.4

Big Rivers Electric Corporation
Case No. 2012-00535

Attachment 2 to Response for PSC 2-27a
2012 Energy Budget

	ENERGY (MWh) - 2012					
	January 2012	February 2012	March 2012	April 2012	May 2012	June 2012
KENERGY	123,923	103,928	94,598	74,872	83,736	110,799
JACKSON PURCHASE	66,755	54,612	50,767	41,038	47,478	62,000
MEADE COUNTY	55,252	46,756	39,818	30,010	31,781	41,079
TOTAL MEMBER RURAL ENERGY	245,930	205,296	185,183	145,920	162,995	213,878
ACCURIDE	1,744	1,602	1,823	1,784	1,894	1,784
ALCOA	86	78	99	121	83	121
ALERIS	14,931	14,375	15,269	14,999	15,600	14,999
ALLIED (STEMPORT)	2,797	2,711	3,015	2,519	2,384	2,519
ARMSTRONG DOCK	2,045	2,012	1,703	1,140	1,194	1,340
ARMSTRONG EQUALITY	997	1,038	1,267	1,299	1,198	1,234
ARMSTRONG LEWIS CREEK	250	250	250	250	250	250
ARMSTRONG MIDWAY	2,050	1,993	2,002	1,572	1,551	1,572
ARVIN ROLL COATER	1,739	1,570	1,739	1,739	1,739	1,739
DOMTAR	12,508	11,557	14,328	11,649	15,546	16,895
DOTIKI # 3	544	493	573	542	543	544
HOPKINS CO. COAL	190	74	187	138	170	167
KB ALLOY	655	548	651	629	535	629
KIMBERLY CLARK	25,301	23,563	25,831	24,983	25,599	24,983
KMMC, Inc./P&M/Cochise	92	83	59	48	40	37
PATRIOT COAL	2,173	2,386	2,293	2,244	2,005	1,648
Shell Oil JP Industrials	1,250	1,250	1,250	1,250	1,250	1,250
SOUTHWIRE COMPANY	4,174	3,681	4,159	3,950	4,299	4,073
TYSON	5,026	4,578	5,022	5,220	5,528	5,220
VALLEY	746	847	809	809	760	769
TOTAL MEMBER IND'L ENERGY	79,298	74,689	82,329	76,885	82,168	81,773
ALCAN	268,316	251,005	268,316	259,661	268,316	259,661
CENTURY	351,436	328,763	351,436	340,099	351,436	340,099
TOTAL	944,980	859,753	887,264	822,565	864,915	895,411

Big Rivers Electric Corporation
Case No. 2012-00535

Attachment 2 to Response for PSC 2-27a
2012 Energy Budget

	ENERGY (MWh) - 2012						
	July 2012	August 2012	September 2012	October 2012	November 2012	December 2012	TOTAL
KENERGY	123,309	119,333	90,778	77,677	89,919	121,252	1,214,123
JACKSON PURCHASE	70,359	67,647	51,513	43,409	49,470	66,275	671,323
MEADE COUNTY	46,345	44,080	34,226	30,850	37,508	54,807	492,512
TOTAL MEMBER RURAL ENERGY	240,014	231,059	176,517	151,935	176,896	242,334	2,377,958
ACCURIDE	1,894	1,894	1,784	1,894	1,784	1,894	21,775
ALCOA	83	83	121	83	121	83	1,162
ALERIS	15,600	15,600	14,999	15,600	14,999	15,600	182,571
ALLIED (STEMPORT)	2,384	2,384	2,519	2,384	2,519	2,384	30,519
ARMSTRONG DOCK	1,530	694	863	1,096	1,124	1,506	16,247
ARMSTRONG EQUALITY	1,410	1,410	1,234	1,410	1,410	1,410	15,317
ARMSTRONG LEWIS CREEK	250	250	250	250	250	250	3,000
ARMSTRONG MIDWAY	1,551	1,551	1,572	1,551	1,572	1,551	20,088
ARVIN ROLL COATER	1,739	1,739	1,739	1,739	1,739	1,739	20,699
DOMTAR	17,856	15,966	14,917	12,092	14,171	13,573	171,058
DOTIKI # 3	566	566	566	566	566	566	6,635
HOPKINS CO. COAL	174	174	174	174	174	174	1,970
KB ALLOY	535	535	629	535	629	535	7,045
KIMBERLY CLARK	25,599	25,598	24,980	25,598	24,981	25,598	302,614
KMMC, Inc./P&M/Cochise	37	37	37	37	37	37	581
PATRIOT COAL	1,889	2,244	2,244	1,889	1,889	1,889	24,793
Shell Oil JP Industrials	1,250	1,250	1,250	1,250	1,250	1,250	15,000
SOUTHWIRE COMPANY	4,108	3,791	3,863	4,112	3,866	3,781	47,857
TYSON	5,528	5,528	5,220	5,528	5,220	5,528	63,146
VALLEY	778	778	778	778	809	809	9,470
TOTAL MEMBER IND'L ENERGY	84,761	82,072	79,739	78,566	79,110	80,157	961,547
ALCAN	268,316	268,316	259,661	268,316	259,661	268,316	3,167,862
CENTURY	351,436	351,436	340,099	351,436	340,099	351,436	4,149,210
TOTAL	944,527	932,883	856,016	850,253	855,766	942,243	10,656,577

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

**Response to Commission Staff's Second Request for Information
dated February 14, 2013**

February 28, 2013

Item 28) ***Refer to the Direct Testimony of James V. Haner at pages 5-8. For each of the labor and labor-related cost items discussed on these pages, provide the actual expense levels reported on Big Rivers' statement of operations for calendar year 2011 and calendar year 2012 and the expense levels included in the forecast period.***

Response) Please find the attached schedule of labor and labor-related actual costs requested for calendar years 2011 and 2012. Also, find the labor and labor-related costs requested for the forecast period.

Witness) James V. Haner

Big Rivers Electric Corporation
Case No. 2012-00535

Attachment to Response for PSC 2-28
Labor and Labor Related Cost Items

Line No. (A)	Description (B)	Actuals 2011 (C)	Actuals 2012 (D)	Forecasted Test Year (E)
1	WAGES & SALARIES EXPENSE:			
2	TOTAL STRAIGHT-TIME WAGES & SALARIES	$ 39,965,926	$ 41,245,927	$ 37,162,703
3	TOTAL OVERTIME WAGES	$ 5,662,947	$ 5,425,193	$ 4,578,817
4	TOTAL PAYROLL	$ 45,628,873	$ 46,671,120	$ 41,741,520
5				
6	PAYROLL TAX EXPENSE:			
7	FICA	$ 3,386,356	$ 3,365,931	$ 3,095,322
8	FUTA/SUTA	$ 117,652	$ 102,062	$ 103,416
9	TOTAL PAYROLL TAXES	$ 3,504,007	$ 3,467,993	$ 3,198,738
10				
11	BENEFITS EXPENSE:			
12	401K PLAN	$ 1,244,533	$ 1,218,725	$ 1,262,530
13	DENTAL INSURANCE	$ 483,288	$ 378,349	$ 356,985
14	GROUP LIFE INSURANCE	$ 251,090	$ 239,919	$ 224,047
15	LONG TERM DISABILITY INSURANCE	$ 266,885	$ 283,219	$ 270,814
16	MEDICAL INSURANCE	$ 9,440,875	$ 6,825,986	$ 7,198,200
17	POST RETIREMENT MEDICAL (SFAS 106)	$ 1,981,635	$ 1,822,990	$ 1,181,502
18	PENSION	$ 4,392,440	$ 7,273,239	$ 5,174,652
19	WORKERS COMP	$ 835,846	$ 670,479	$ 605,939
20	TOTAL BENEFITS	$ 18,896,592	$ 18,712,905	$ 16,274,667
21				
22	GRAND TOTAL	$ 68,029,472	$ 68,852,019	$ 61,214,925

BIG RIVERS ELECTRIC CORPORATION

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

Response to Commission Staff's Second Request for Information dated February 14, 2013

February 28, 2013

Item 29) ***Refer to page 30 of the Direct Testimony of Ted J. Kelly and Exhibit Kelly-1, page ES-6, which summarizes the 2012 Depreciation Rate Study Mr. Kelly sponsors. The summary includes a comparison of the existing depreciation rates and proposed depreciation rates applied to Big Rivers' July 31, 2012 plant balances, which results in a comparison of annual depreciation expense at existing and proposed rates. Provide a similar summary of annual depreciation expense at existing and proposed depreciation rates based on the average plant balances for the forecast period.***

Response) Please see the attachment to this response.

Witness) Billie J. Richert

Big Rivers Electric Corporation
Case No. 2012-00535

Attachment to Response for PSC 2-29
Table ES-1 2012 Depreciation Rate Study Summary

Account	Description	Forecasted Test Year 9/13-8/14 Average Plant Balance	Reserve Balance	Reserve Ratio	Existing Depreciation Rate	Proposed Depreciation Rate	Annual Depreciation Expense Existing	Proposed	Variance	
		- $ -			- % -	- % -	- $ -	- $ -	- $ -	
310	Land & Land Improvements	4,537,577								
PRODUCTION PLANT [1]										
340	Land	475,968								
311	Structures	127,011,123			1.38%	1.38%	$1,752,753	$1,755,827	$3,073	Life Span Method
312	Boiler Plant	709,138,767			1.88%	2.02%	$13,331,809	$14,302,054	$970,245	Life Span Method
312 A-K	Boiler Plant - Environment Complian	584,128,633			2.28%	2.43%	$13,318,133	$14,170,831	$852,699	Life Span Method
312 L-P	Short-Life Production Plant -Environ	12,568,809			20.22%	15.95%	$2,541,413	$2,004,737	($536,676)	Life Span Method
312 V-Z	Short-Life Production Plant -Other	1,207,239			14.39%	25.38%	$173,722	$306,442	$132,720	Life Span Method
314	Turbine	236,132,236			1.91%	1.96%	$4,510,126	$4,620,315	$110,190	Life Span Method
315	Electric Equipment	64,530,879			1.99%	2.03%	$1,284,164	$1,308,709	$24,545	Life Span Method
316	Miscellaneous Equipment	7,195,116			3.78%	4.04%	$271,975	$290,885	$18,910	Life Span Method
341	CT - Structures	154,233			1.17%	1.06%	$1,805	$1,633	($172)	Life Span Method
342	CT - Fuel Holders & Access.	1,442,387			9.10%	9.92%	$131,257	$143,063	$11,806	Life Span Method
343	CT - Prime Movers	4,952,277			3.02%	3.02%	$149,559	$149,414	($145)	Life Span Method
344	CT - Generators	1,102,964			0.50%	0.35%	$5,515	$3,891	($1,624)	Life Span Method
345	CT - Accessory Electrical Equipment	399,274			2.05%	2.93%	$8,185	$11,683	$3,498	Life Span Method
	Subtotal	1,754,977,482					$37,480,416	$39,069,485	$1,589,069	

Big Rivers Electric Corporation
Case No. 2012-00535

Attachment to Response for PSC 2-29
Table ES-1 2012 Depreciation Rate Study Summary

Account	Description	Forecasted Test Year 9/13-8/14 Average Plant Balance	Reserve Balance	Reserve Ratio	Existing Depreciation Rate	Proposed Depreciation Rate	Annual Depreciation Expense Existing	Proposed	Variance	
		- $ -			- % -	- % -	- $ -	- $ -	- $ -	
TRANSMISSION [1]										
350	Land	14,307,110								
352	Structures	6,982,299			1.90%	1.94%	$132,664	$135,459	$2,796	Life Span Method
353	Station Equipment	131,397,679			2.23%	2.29%	$2,930,168	$3,010,692	$80,523	Life Span Method
354	Towers	8,593,544			1.42%	1.36%	$122,028	$117,062	($4,967)	Life Span Method
355	Poles	44,738,160			2.06%	2.03%	$921,606	$906,086	($15,520)	Life Span Method
356	Lines	48,403,997			1.69%	1.81%	$818,028	$877,722	$59,694	Life Span Method
	Subtotal	254,422,789					$4,924,494	$5,047,021	$122,527	
GENERAL PLANT [2]										
389	Land	407,251								
390	Structures [1]	5,325,369			2.84%	3.76%	$151,240	$200,479	$49,239	Life Span Method
1.0/391.6/391.7	Office Furniture & Equipment	837,312			17.12%	9.11%	$143,348	$76,317	($67,031)	Whole Life Method
391.2	Computer	25,483,810			10.29%	9.88%	$2,622,284	$2,518,453	($103,831)	Whole Life Method
391.3	Engineering Computer	0								
392.2	Vehicles - General	2,850,612			4.39%	8.58%	$125,142	$244,715	$119,574	Whole Life Method
392.3	Vehicles - Transmission	1,257,240			6.14%	8.31%	$77,195	$104,450	$27,256	Whole Life Method
393	Stores Equipment	98,766			4.40%	5.97%	$4,346	$5,900	$1,554	Whole Life Method
394	Tools	748,516			4.61%	6.08%	$34,507	$45,497	$10,990	Whole Life Method
395	Lab Equipment	221,279			4.41%	6.12%	$9,758	$13,541	$3,783	Whole Life Method
396	Power Operated Equipment	838,742			3.70%	4.69%	$31,033	$39,352	$8,319	Whole Life Method
397	Communication Equipment	1,701,797			4.35%	6.25%	$74,028	$106,428	$32,400	Whole Life Method
398	Miscellaneous Equipment	262,351			11.80%	6.05%	$30,957	$15,871	($15,086)	Whole Life Method
	Subtotal	40,033,045					$3,303,838	$3,371,004	$67,165	
TOTAL		**2,049,433,316**					$45,708,748	$47,487,509	1,778,761	

[1] Life Span Method depreciation
[2] Whole Life Method depreciation

BIG RIVERS ELECTRIC CORPORATION

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

Response to Commission Staff's Second Request for Information dated February 14, 2013

February 28, 2013

PSC 2-30) ***Refer to Exhibit Kelly-1 "2012 Depreciation Study" where it states that, "[s]ince the Unwind Closing in 2009, Big Rivers has not performed major maintenance such as valve inspections and turbine inspections on a schedule consistent with prudent utility operations." Describe the steps that Big Rivers will take to ensure that it will perform major maintenance on its generation units.***

Response) Big Rivers has had to defer some maintenance activities since the closing of the unwind transaction in order to reduce expenses to meet the minimum margins for interest ratio ("MFIR") requirements of its loan agreements; however, Big Rivers believes that the maintenance deferrals have been done prudently and judiciously, as unit reliability and availability have not been affected thus far. Big Rivers also acknowledges the statement within its 2012 Depreciation Study, but references Mr. Kelly's Direct Testimony in Tab 71 of this instant proceeding. Beginning on page 13 at line 20, Mr. Kelly states:

> RUS may have misunderstood what we were indicating in the report. As a result of prevailing resource constraints, Big Rivers selectively deferred some major maintenance while continuing routine maintenance. Inspections performed by Burns & McDonnell and a review of operating results over the last several years indicated no adverse conditions as a result of this short term deferral. Burns & McDonnell did review Big Rivers' plans, developed in May 2012, to reschedule the maintenance activities that are described by Bob Berry in his testimony. In

> light of the favorable operating results and assuming timely rescheduling of the deferred maintenance, in our opinion Big Rivers showed good judgment in the use of available resources and its' facilities are being reasonably and prudently operated.

In order to ensure that the deferred maintenance can be performed timely and effectively, Big Rivers' staff has attempted to levelize spending as referenced in the Direct Testimony of Robert W. Berry in Tab 66 of Big Rivers' application in this proceeding. Beginning on page 15 at line 7, Mr. Berry states, "Looking forward to the next planning period, Big Rivers' production staff has assessed the condition of each unit in the fleet individually, and evaluated the risks associated with the deferred maintenance, in order to adjust the future outage schedule to levelize spending and unit outage hours across the period." And at line 15, Mr. Berry states that "by the beginning of 2016, Big Rivers expects to have all of the deferred maintenance completed and have all the units back on a maintenance outage frequency that is consistent with prudent utility operation on a long-term basis." Big Rivers has also filed this instant case seeking an adjustment in its base rates that will provide the necessary revenue to accomplish the aforementioned schedule.

Witness) Robert W. Berry

Item 31) ***Refer to the Siewert Testimony at pages 8-9.***

a. At the top of Page 8, Mr. Siewert states that "[t]he financial model includes a calculation of the Base Fixed Energy (i.e., the model assumes that Base Variable Energy is zero)."

(1) Confirm that the base variable-energy rate consists of the base fuel and non-fuel adjustment clause purchase power adjustment ("Non-FAC PPA"). If this cannot be confirmed, explain.

(2) Explain why the base variable energy is assumed to be zero in the financial model.

b. Beginning on line 17 of page 8, Mr. Siewert states that, for budgeting purposes, Big Rivers assumes all but three of the revenue items listed at the bottom of page 8 and at the top of page 9 are zero. Explain why this assumption is made.

Response)

a.

(1) Confirmed. Since Big Rivers' environmental surcharge base is zero, the Base Variable Rate currently consists of base fuel and base Non-FAC PPA.

(2) From a financial standpoint, Variable Energy, whether positive or negative, is not budgeted because it would have no impact on Big Rivers' budgeted net margins. The Smelter contracts are designed so that Big Rivers' fixed costs related to serving the Smelters are covered no matter how much of the Base Fixed Energy they choose to consume themselves.

b. These items are assumed to be zero because they either do not currently apply to the smelter bill, or if they do apply, they would have no impact on the net margins of Big Rivers. For budgeting purposes, Big Rivers is indifferent as to how much of the Base Fixed Energy the smelters actually consume themselves, versus any other combination of ways they may utilize the power available to them under the smelter contracts. Because the smelter contracts are designed to ensure that Big Rivers' fixed costs related to serving the smelters are covered, Big Rivers' net margins are not affected by the various revenue items listed in the Direct Testimony of Mr. Siewert that are assumed to be zero.

Witness) Travis A. Siewert

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

Response to Commission Staff's Second Request for Information dated February 14, 2013

February 28, 2013

Item 32) ***Refer to Exhibit Siewert-2, pages 25-26. Explain how the amounts on the Economic Reserve lines (Lines 29 and 46) were calculated.***

Response) The calculation of the amounts reflected on the Economic Reserve lines (Lines 29 and 46) is designed to mirror the Member Rate Stability Mechanism (MRSM) tariff rider. As such, the amount is designed to offset the Fuel Adjustment Clause (FAC) and the Environmental Surcharge (ES), less the Expense Mitigation Factor (EMF), less the Unwind Surcredit (US), plus fuel rolled into base rates since July 17, 2009.

Witness) Travis A. Siewert

BIG RIVERS ELECTRIC CORPORATION

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

Response to Commission Staff's Second Request for Information dated February 14, 2013

February 28, 2013

Item 33) ***Refer to the Wolfram Testimony, pages 21-26 wherein Mr. Wolfram discusses the methodology used in the cost of service study ("COSS"). State whether all revenue and expense amounts in the COSS filed in this proceeding have been allocated using the same allocation factors as used in the COSS filed in Case No. 2011-00036.[2] If the response is no, explain the differences.***

Response) The selection of certain allocation vectors for particular expenses and revenues is the same in the COSS filed in this case as they were in the COSS filed in Case No. 2011-00036. For example, the "12CP" allocation vector was used to allocate Production Demand costs in both cases. Note this does not mean that the actual values in the "12CP" allocation vectors in both cases are identical; they are not, because the test period peak load ratios differ from case to case—but in both cases, the appropriate 12CP amounts were used to allocate the Production Demand costs.

Witness) John Wolfram

[2] Case No. 2011-00036, Application of Big Rivers Electric Corporation for a General Adjustment in Rates (Ky PSC Jan. 29, 2013).

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

Response to Commission Staff's Second Request for Information dated February 14, 2013

February 28, 2013

Item 34) ***Refer to pages 33-34 of the Wolfram Testimony. Starting at the bottom of page 33, Mr. Wolfram states that Big Rivers is proposing an energy charge of $0.03000 for the Rural and Large Industrial Customer ("LIC") classes and that this charge "approximates Big Rivers' annual production cost on a per-unit basis." Provide the supporting calculation of Big Rivers' annual production cost on a per-unit basis.***

Response) Support for Big Rivers' annual production cost on a per-unit basis is provided under a petition for confidential treatment in the file entitled "Big Rivers 2013-2016 PCM (Confidential).xls" in Big Rivers' response to PSC 1-57. In that file, on the tab labeled Monthly Resource Report, row 352 shows [redacted]. These values are reproduced in the attachment. The establishment of an energy charge of $30.00 per MWh for both the RDS and LIC classes approximates this amount.

Witness) John Wolfram

Big Rivers Electric Corporation
Case No. 2012-00535

Attachment to Response for PSC 2-34
Data from Big Rivers 2013-2016 Production Cost Model

Month	Total Thermal Total Variable Generation Cost $/MWH
Sep-13	[redacted]
Oct-13	
Nov-13	
Dec-13	
Jan-14	
Feb-14	
Mar-14	
Apr-14	
May-14	
Jun-14	
Jul-14	
Aug-14	
AVG	

BIG RIVERS ELECTRIC CORPORATION

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

Response to Commission Staff's Second Request for Information
dated February 14, 2013

February 28, 2013

Item 35) ***Refer to page 36 of the Wolfram Testimony, lines 4-6. Mr. Wolfram states that the estimated impact of the Member Rate Stability Mechanism is a credit of $.0101 per kWh for the Rural class and a credit of $.0093 per kWh for the LIC class. Provide the supporting calculations for these amounts***

Response) See the attached pages for supporting calculations. The first set is a reproduction of Exhibit Wolfram-5 which shows the values gross of MRSM. The second set a variation of Exhibit Wolfram-5 which shows the values net of MRSM, with the additional data points for the MRSM highlighted. The highlighted rows show the $0.0101 per kWh for the Rurals and the $0.0093 per kWh for the LIC class; these amounts are simply the total dollar amount from the Big Rivers Financial Model divided by the total consumption. Note that the total dollar amounts of the increases for each class and in total do not change; it is only the percentages that vary.

Witness) John Wolfram

Big Rivers Electric Corporation
Case No. 2012-00535

Attachment to Response for PSC 2-35 Gross of MRSM
Cost of Service Study - Billing Determinants - Present and Proposed Rates
12 Months Ended August 31, 2014

Rate		Billing Determinants		Current Rate Charge		Current Rate Billings	Proposed Rate Charge		Proposed Rate Billings	Variance Billings
Rural Delivery Point Service										
Demand Charge	CP	5,322,297	kW-Mo	9.50	/kW-Mo	$ 50,561,820	16.95	/kW-Mo	$ 90,190,052	$ 39,628,232
Energy Charge		2,436,557,000	kWh	$ 0.029736	/kWh	72,453,459	$ 0.030000	/kWh	73,096,710	643,251
Total Demand and Energy Charges				0.050487		$ 123,015,279	0.067015		$ 163,286,762	$ 40,271,483
Non-Smelter Non-FAC PPA				(0.000781)		(1,903,467)	(0.000781)		(1,903,467)	-
FAC				0.005141		12,526,275	0.005141		12,526,275	-
Environmental Surcharge				0.003578		8,718,352	0.003744		9,123,147	404,795
Surcredit				(0.001738)		(4,235,358)	(0.001738)		(4,235,358)	-
Total		2,436,557,000	kWh	0.056687		$ 138,121,080	0.073381		$ 178,797,359	$ 40,676,278
Increase	$								**$ 40,676,278**	*Gross of MRSM*
Increase	%								29.4%	
Large Industrial Customer Delivery Point Service										
Demand Charge	NCP	1,674,594	kW-Mo	10.50	/kW-Mo	$ 17,583,237	12.41	/kW-Mo	$ 20,788,374	$ 3,205,137
Energy Charge		943,698,679	kWh	$ 0.024505	/kWh	23,125,336	$ 0.030000	/kWh	$ 28,310,960	$ 5,185,624
Total Demand and Energy Charges				0.043137		$ 40,708,573			$ 49,099,334	$ 8,390,761
Non-Smelter Non-FAC PPA				(0.000781)		(737,229)	(0.000781)		(737,229)	-
FAC				0.005125		4,836,245	0.005125		4,836,245	-
Environmental Surcharge				0.003109		2,933,572	0.002957		2,790,740	(142,833)
Surcredit				(0.001777)		(1,677,110)	(0.001777)		(1,677,110)	-
Total		943,698,679	kWh	0.048812		$ 46,064,053	0.057552		$ 54,311,981	$ 8,247,929
Increase	$								**$ 8,247,929**	*Gross of MRSM*
Increase	%								17.9%	

Big Rivers Electric Corporation
Case No. 2012-00535

Attachment to Response for PSC 2-35 Gross of MRSM
Cost of Service Study - Billing Determinants - Present and Proposed Rates
12 Months Ended August 31, 2014

		Current Rate		Proposed Rate		Variance
Rate	Billing Determinants	Charge	Billings	Charge	Billings	Billings
Smelter						
Base Energy Charge						
Base Fixed Energy Charge	3,159,206,400 kWh	0.039432 /kWh	$ 124,573,827	$ 0.047603 /kWh	$ 150,387,702	$ 25,813,875
Base Variable Energy Charge	- kWh	0.012470 /kWh	-	$ 0.021806 /kWh	-	-
Total Base Energy Charge	3,159,206,400 kWh	0.039432	$ 124,573,827		$ 150,387,702	$ 25,813,875
Other Charges or Credits						
TIER Adjustment Charge		0.002950	$ 9,319,659	0.002950	$ 9,319,659	$ -
Non-FAC PPA		(0.000369)	(1,165,347)	(0.000369)	$ (1,165,347)	-
FAC		0.005121	16,176,808	0.005121	$ 16,176,808	-
Environmental Surcharge		0.002829	8,938,660	0.002746	$ 8,676,698	(261,962)
Surcharge		0.001872	5,912,468	0.001872	$ 5,912,468	-
Total	3,159,206,400	0.051835	$ 163,756,075	0.059923	$ 189,307,988	$ 25,551,913
Increase $					$ 25,551,913	
Increase %					15.6%	
TOTAL	6,539,462,079	0.053206	$ 347,941,208	0.064595	$ 422,417,328	$ 74,476,120
INCREASE				0.011389	$ 74,476,120	*Gross of MRSM*
					21.4%	

Big Rivers Electric Corporation
Case No. 2012-00535

Attachment to Response 2-35 Net of MRSM
Cost of Service Study - Billing Determinants - Present and Proposed Rates
12 Months Ended August 31, 2014

Rate		Billing Determinants	Current Rate Charge	Current Rate Billings	Proposed Rate Charge	Proposed Rate Billings	Variance Billings
Rural Delivery Point Service							
Demand Charge	CP	5,322,297 kW-Mo	9.50 /kW-Mo	$ 50,561,820	16.95 /kW-Mo	$ 90,190,052	$ 39,628,232
Energy Charge		2,436,557,000 kWh	$ 0.029736 /kWh	72,453,459	$ 0.030000 /kWh	73,096,710	643,251
Total Demand and Energy Charges			0.050487	$ 123,015,279	0.067015	$ 163,286,762	$ 40,271,483
Non-Smelter Non-FAC PPA			(0.000781)	(1,903,467)	(0.000781)	(1,903,467)	-
FAC			0.005141	12,526,275	0.005141	12,526,275	-
Environmental Surcharge			0.003578	8,718,352	0.003744	9,123,147	404,795
Surcredit			(0.001738)	(4,235,358)	(0.001738)	(4,235,358)	-
MRSM			(0.010114)	(24,642,904)	(0.010114)	(24,642,904)	-
Total		2,436,557,000 kWh	0.046573	$ 113,478,176	0.063267	$ 154,154,454	$ 40,676,278
Increase $						**$ 40,676,278**	*Net of MRSM*
Increase %						35.8%	
Large Industrial Customer Delivery Point Service							
Demand Charge	NCP	1,674,594 kW-Mo	10.50 /kW-Mo	$ 17,583,237	12.41 /kW-Mo	$ 20,788,374	$ 3,205,137
Energy Charge		943,698,679 kWh	$ 0.024505 /kWh	23,125,336	$ 0.030000 /kWh	$ 28,310,960	$ 5,185,624
Total Demand and Energy Charges			0.043137	$ 40,708,573		$ 49,099,334	$ 8,390,761
Non-Smelter Non-FAC PPA			(0.000781)	(737,229)	(0.000781)	(737,229)	-
FAC			0.005125	4,836,245	0.005125	4,836,245	-
Environmental Surcharge			0.003109	2,933,572	0.002957	2,790,740	(142,833)
Surcredit			(0.001777)	(1,677,110)	(0.001777)	(1,677,110)	-
MRSM			(0.009302)	(8,778,318)	(0.009302)	(8,778,318)	-
Total		943,698,679 kWh	0.039510	$ 37,285,735	0.048250	$ 45,533,663	$ 8,247,929
Increase $						**$ 8,247,929**	*Net of MRSM*
Increase %						22.1%	

Big Rivers Electric Corporation
Case No. 2012-00535

Attachment to Response 2-35 Net of MRSM
Cost of Service Study - Billing Determinants - Present and Proposed Rates
12 Months Ended August 31, 2014

Rate	Billing Determinants	Current Rate Charge	Current Rate Billings	Proposed Rate Charge	Proposed Rate Billings	Variance Billings
Smelter						
Base Energy Charge						
Base Fixed Energy Charge	3,159,206,400 kWh	0.039432 /kWh	$ 124,573,827	$ 0.047603 /kWh	$ 150,387,702	$ 25,813,875
Base Variable Energy Charge	- kWh	0.012470 /kWh	-	$ 0.021806 /kWh	-	-
Total Base Energy Charge	3,159,206,400 kWh	0.039432	$ 124,573,827		$ 150,387,702	$ 25,813,875
Other Charges or Credits						
TIER Adjustment Charge		0.002950	$ 9,319,659	0.002950	$ 9,319,659	$ -
Non-FAC PPA		(0.000369)	(1,165,347)	(0.000369)	$ (1,165,347)	-
FAC		0.005121	16,176,808	0.005121	$ 16,176,808	-
Environmental Surcharge		0.002829	8,938,660	0.002746	$ 8,676,698	(261,962)
Surcharge		0.001872	5,912,468	0.001872	$ 5,912,468	-
Total	3,159,206,400	0.051835	$ 163,756,075	0.059923	$ 189,307,988	$ 25,551,913
Increase $					$ 25,551,913	
Increase %					15.6%	
TOTAL	6,539,462,079	0.048096	$ 314,519,986	0.059484	$ 388,996,105	$ 74,476,120
INCREASE				0.011389	$ 74,476,120	
					23.7%	*Net of MRSM*

BIG RIVERS ELECTRIC CORPORATION

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

Response to Commission Staff's Second Request for Information dated February 14, 2013

February 28, 2013

Item 36) ***Refer to page 37 of the Wolfram Testimony, lines 5-8, which state that if the Commission issues an order on rehearing in Case No. 2011-00036 resulting in a change in base rates, Big Rivers would need to adjust the rates proposed in this proceeding. On January 29, 2013, an order on rehearing was issued in Case No. 2011-00036 which resulted in a change to Big Rivers' rates. Provide revisions of all exhibits that will change due to this change in Big Rivers' rates. For Exhibits Wolfram-3, -4, and -5 provide the revisions in both hard copy and electronic spreadsheets with the formulas intact and unprotected, and with all rows and columns accessible.***

Response) The following exhibits are provided as a result of the change in base rates approved in the order on rehearing dated January 29, 2013 in Case No. 2011-00036 ("the Rehearing Order"). (The naming convention includes the ".2" suffix to distinguish the revised exhibit from the exhibits filed with the application in this case.)

1) Exhibit Yockey-2.2 – Summary of Proposed Changes to Tariff Rates
2) Exhibit Siewert-2.2 – Big Rivers Financial Model
3) Exhibit Siewert-3.2 – Financial Results With and Without Rate Increase
4) Exhibit Wolfram-2.2 – Revenue Requirements Analysis

5) Exhibit Wolfram-3.2 – Cost of Service Study: Functional Assignment and Classification
6) Exhibit Wolfram-4.2 – Cost of Service Study: Allocation to Rate Classes
7) Exhibit Wolfram-5.2 – Billing Determinants: Present & Proposed Rates
8) Exhibit Wolfram-6.2 – Summary of Proposed Increase
9) Exhibit Wolfram-7.2 – Estimate of Retail Rate Increase

The revised Wolfram and Siewert exhibits are provided under a petition for confidential treatment and are also provided in electronic form on the CONFIDENTIAL CD accompanying this response.

In addition, the revised exhibits reflect corrections to mathematical errors identified in other data requests. These include the following:

a) Correction of the expense adjustments for FAC, ES, Non-FAC PPA, and Lobbying Expenses identified in PSC 2-39;
b) Elimination of the rounding errors identified in PSC 2-40;
c) Correction of the calculation of depreciation expense on fully-depreciated plant identified in AG-277(c).

The revised exhibits do not reflect the impact of Big Rivers' amended application in Case No. 2012-00492. The effect of the amended application is described in the response to PSC 2-13, but because the request has not yet been approved by the Commission, the impact is not yet incorporated here.

In sum, the incorporation of the Rehearing Order and the corrections noted above results in a $1,507,989 decrease to the originally-filed revenue deficiency.

Witnesses) John Wolfram, Travis A. Siewert

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

Standard Rate Schedule	Rate	Sheet Number(s)	Current Rate	Proposed Rate[1]	Incr. (Decr.)[1]
RDS	Demand	1	$9.697 per kW	$16.848 per kW	$7.151 per kW
	Energy	1	$0.029736 per kWh	$0.030000 per kWh	$0.000264 per kWh
LIC	Demand	7	$10.5000 per kW	$12.330 per kW	$1.830 per kW
	Energy	7	$0.024508 per kWh	$0.030000 per kWh	$0.005492 per kWh
QFS	*On-Peak Maintenance Service*				
	Demand per Week	24	$2.238 per kW	$3.931 per kW	$1.693 per kW
	Energy	24	$0.029736 per kWh	$0.030000 per kWh	$0.000264 per kWh
	Off-Peak Maintenance Service				
	Demand per Week	24	$2.238 per kW	$3.931 per kW	$1.693 per kW

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

Big Rivers Electric Corporation
Case No. 2012-00535
Big Rivers Financial Model

		2013 January	2013 February	2013 March	2013 April	2013 May	2013 June	2013 July	2013 August	2013 September	2013 October	2013 November	2013 December	2013 Total
1														
2	**I. Sales**													
3														
4	**Energy (TWH)**													
5	Rural	0.25	0.21	0.19	0.15	0.17	0.22	0.24	0.23	0.18	0.15	0.18	0.25	2.41
6	Large Industrial	0.08	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.94
7	Century	0.35	0.32	0.35	0.34	0.35	0.34	0.35	0.22	0.00	0.00	0.00	0.00	2.62
8	Alcan	0.28	0.25	0.28	0.27	0.28	0.27	0.27	0.27	0.26	0.27	0.26	0.27	3.20
9	Market	[redacted]												
10	Total Energy Sales	1.07	0.96	1.03	0.91	0.94	0.96	1.03	1.00	0.68	0.75	0.72	0.75	10.78
11														
12	**Demand (MW)**													
13	Rural	540.18	482.11	418.81	328.15	374.55	472.17	493.51	533.48	416.26	336.41	377.17	494.38	5,267.19
14	Large Industrial	139.27	139.90	139.11	139.40	138.43	138.53	143.19	143.54	136.42	138.47	138.43	138.60	1,673.29
15														
16	**II. Rates, Accrual Based ($ / MWH)**													
17														
18	**Rural**													
19	Load Factor (%)	62.01%	64.21%	60.23%	62.59%	59.28%	63.76%	66.25%	59.00%	59.69%	61.52%	66.01%	66.76%	62.67%
20	Demand ($/ KW-mo.)	9.70	9.70	9.70	9.70	9.70	9.70	9.70	12.23	16.85	16.85	16.85	16.85	12.19
21	Energy ($/ MWH)	29.74	29.74	29.74	29.74	29.74	29.74	29.74	29.83	30.00	30.00	30.00	30.00	29.83
22	Base Rate ($/ MWH)	50.76	52.21	51.38	51.25	51.72	50.86	49.41	57.70	69.20	66.81	65.45	63.92	56.40
23														
24	Non-Smelter Non-FAC PPA	(1.36)	(1.36)	(1.36)	(1.36)	(1.36)	(1.36)	(1.36)	(1.36)	(0.78)	(0.78)	(0.78)	(0.78)	(1.18)
25	FAC	3.79	3.93	3.92	3.96	3.96	4.11	4.63	4.21	4.70	4.48	4.61	4.67	4.25
26	Environmental Surcharge	3.19	3.27	3.31	3.09	3.23	3.21	3.05	3.68	4.35	4.13	3.71	3.42	3.45
27	Surcredit	(3.54)	(3.85)	(4.33)	(5.05)	(4.75)	(3.87)	(3.53)	(2.87)	(1.91)	(2.14)	(1.91)	(1.54)	(3.23)
28	Total	3.44	3.34	2.90	1.99	2.44	3.45	4.15	5.03	7.14	6.47	6.41	6.55	4.46
29	Economic Reserve	(7.65)	(7.56)	(7.11)	(6.21)	(6.65)	(7.66)	(7.36)	(8.24)	(10.35)	(9.68)	(9.63)	(9.76)	(8.16)
30	Rural Economic Reserve	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
31	TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
32	Effective Rate ($/ MWH)	45.19	46.64	45.81	45.69	46.15	45.29	44.84	53.13	65.21	62.82	61.45	59.93	51.53
33														

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		2013 January	2013 February	2013 March	2013 April	2013 May	2013 June	2013 July	2013 August	2013 September	2013 October	2013 November	2013 December	2013 Total
34	**Large Industrial**													
35	Load Factor (%)	75.77%	79.04%	77.68%	76.94%	76.72%	77.06%	77.88%	76.94%	78.20%	76.55%	77.18%	76.59%	77.20%
36	Demand ($/ KW-mo.)	10.50	10.50	10.50	10.50	10.50	10.50	10.50	11.15	12.33	12.33	12.33	12.33	11.16
37	Energy ($/ MWH)	24.51	24.51	24.51	24.51	24.51	24.51	24.51	26.46	30.00	30.00	30.00	30.00	26.49
38	Power Factor Penalty/ Demand Cr. (Lrg. Ind.)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
39	Base Rate ($/ MWH)	43.13	44.28	42.68	43.46	42.90	43.43	42.63	45.93	51.90	51.65	52.19	51.64	46.29
40														
41	Non-Smelter Non-FAC PPA	(1.36)	(1.36)	(1.36)	(1.36)	(1.36)	(1.36)	(1.36)	(1.36)	(0.78)	(0.78)	(0.78)	(0.78)	(1.17)
42	FAC	3.79	3.93	3.92	3.96	3.96	4.11	4.63	4.21	4.70	4.48	4.61	4.67	4.25
43	Environmental Surcharge	2.74	2.81	2.79	2.65	2.72	2.77	2.67	2.98	3.33	3.25	3.01	2.80	2.88
44	Surcredit	(3.54)	(3.85)	(4.33)	(5.05)	(4.75)	(3.87)	(3.53)	(2.87)	(1.91)	(2.14)	(1.91)	(1.54)	(3.27)
45	Total	3.00	2.88	2.38	1.56	1.93	3.01	3.77	4.33	6.12	5.59	5.71	5.94	3.85
46	Economic Reserve	(7.21)	(7.09)	(6.59)	(5.77)	(6.14)	(7.22)	(6.98)	(7.54)	(9.33)	(8.80)	(8.92)	(9.15)	(7.56)
47	TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
48	Effective Rate ($/ MWH)	37.56	38.71	37.11	37.89	37.33	37.86	38.06	41.37	47.91	47.65	48.20	47.64	41.42
49														
50	**Non-Smelter Member Blend**													
51	Base Rate ($/ MWH)	48.93	50.12	48.77	48.58	48.87	48.91	47.69	54.65	64.01	61.67	61.47	60.93	53.56
52														
53	Non-Smelter Non-FAC PPA	(1.36)	(1.36)	(1.36)	(1.36)	(1.36)	(1.36)	(1.36)	(1.36)	(0.78)	(0.78)	(0.78)	(0.78)	(1.17)
54	FAC	3.79	3.93	3.92	3.96	3.96	4.11	4.63	4.21	4.70	4.48	4.61	4.67	4.25
55	Environmental Surcharge	3.08	3.15	3.15	2.94	3.07	3.09	2.95	3.50	4.04	3.83	3.50	3.27	3.29
56	Surcredit	(3.54)	(3.85)	(4.33)	(5.05)	(4.75)	(3.87)	(3.53)	(2.87)	(1.91)	(2.14)	(1.91)	(1.54)	(3.24)
57	Total	3.33	3.22	2.74	1.84	2.28	3.33	4.05	4.85	6.83	6.17	6.20	6.40	4.29
58	Economic Reserve	(7.55)	(7.43)	(6.95)	(6.06)	(6.49)	(7.54)	(7.26)	(8.06)	(10.04)	(9.38)	(9.41)	(9.61)	(7.99)
59	Rural Economic Reserve	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
60	TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61	Effective Rate ($/ MWH)	43.36	44.55	43.20	43.01	43.30	43.35	43.12	50.08	60.01	57.68	57.47	56.94	48.69
62														

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		2013 January	2013 February	2013 March	2013 April	2013 May	2013 June	2013 July	2013 August	2013 September	2013 October	2013 November	2013 December	2013 Total
63	**Smelters**													
64	Base Rate	39.44	39.44	39.44	39.44	39.44	39.44	39.44	40.71	47.49	47.49	47.49	47.49	41.00
65	TIER Adjustment	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.95
66	Total	42.39	42.39	42.39	42.39	42.39	42.39	42.39	43.66	50.44	50.44	50.44	50.44	43.95
67	Non-FAC PPA	(0.59)	(0.56)	(0.57)	(0.55)	(0.57)	(0.58)	(0.59)	(0.54)	(0.35)	(0.34)	(0.35)	(0.42)	(0.53)
68	FAC	3.79	3.93	3.92	3.96	3.96	4.11	4.63	4.21	4.70	4.48	4.61	4.67	4.16
69	Environmental Surcharge	2.48	2.48	2.54	2.38	2.47	2.49	2.44	2.72	3.03	2.97	2.73	2.56	2.55
70	Surcharge	1.85	1.92	1.85	1.87	1.85	1.87	1.86	1.87	1.88	1.86	1.88	1.86	1.87
71	TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
72	Effective Rate ($/ MWH)	49.92	50.15	50.13	50.04	50.10	50.28	50.72	51.92	59.70	59.41	59.30	59.11	52.00
73														
74	Market	32.37	31.45	30.37	31.60	29.63	32.71	41.25	33.26	28.45	28.08	27.89	30.71	30.78

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		2013 January	2013 February	2013 March	2013 April	2013 May	2013 June	2013 July	2013 August	2013 September	2013 October	2013 November	2013 December	2013 Total
75														
76	**III. Statement of Operations (Millions of $)**													
77														
78	Electric Energy Revenues	[redacted]												
79	Income From Leased Property Net													
80	Other Operating Revenue and Income	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	3.70
81	**TOTAL OPER. REVENUES & PAT. CAPITAL**	[redacted]												
82														
83	Operating Expense-Production-Excluding Fuel	[redacted]												
84	Operating Expense-Production-Fuel													
85	Operating Expense-Other Power Supply													
86	Operating Expense-Transmission													
87	Operating Expense-RTO/ISO													
88	Operating Expense-Distribution													
89	Operating Expense-Customer Accounts													
90	Operating Expense-Customer Service and Information													
91	Operating Expense-Sales													
92	Operating Expense-Administrative and General													
93	**TOTAL OPERATION EXPENSE**													
94														
95	Maintenance Expense-Production	[redacted]												
96	Maintenance Expense-Transmission													
97	Maintenance Expense-Distribution													
98	Maintenance Expense-General Plant													
99	**TOTAL MAINTENANCE EXPENSE**													
100														

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		2013 January	2013 February	2013 March	2013 April	2013 May	2013 June	2013 July	2013 August	2013 September	2013 October	2013 November	2013 December	2013 Total
101	Depreciation and Amortization Expense	3.44	3.44	3.44	3.45	3.47	3.48	3.49	3.49	3.64	3.64	3.65	3.66	42.27
102	Taxes	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
103	Interest on Long-Term Debt	3.80	3.49	3.93	3.84	3.94	3.80	3.94	3.94	3.82	3.97	3.87	3.97	46.31
104	Interest Charged to Construction - Credit	(0.00)	(0.01)	(0.02)	(0.05)	(0.04)	(0.06)	(0.08)	(0.04)	(0.06)	(0.10)	(0.14)	(0.18)	(0.77)
105	Other Interest Expense	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
106	Asset Retirement Obligation													
107	Other Deductions	0.05	0.04	0.05	0.05	0.04	0.06	0.04	0.04	0.04	0.05	0.05	0.07	0.58
108														
109	**TOTAL COST OF ELECTRIC SERVICE**	[redacted]												
110														
111	**OPERATING MARGINS**	3.85	3.07	(0.86)	(3.52)	(5.95)	0.79	2.68	2.60	(0.39)	(2.74)	0.14	3.71	3.39
112														
113	Interest Income	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.16	2.02
114	Allowance For Funds Used During Construction													
115	Income (Loss) From Equity Investments													
116	Other Non-Operating Income (Net)													
117	Generation and Transmission Capital Credits													
118	Other Capital Credits and Patronage Dividends	0.00	0.00	1.24	0.03	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	1.27
119	Extraordinary Items													
120	**NET PATRONAGE CAPITAL OR MARGIN**	4.02	3.24	0.55	(3.33)	(5.78)	0.96	2.85	2.78	(0.22)	(2.57)	0.31	3.88	6.68
121														
122														

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		2013 January	2013 February	2013 March	2013 April	2013 May	2013 June	2013 July	2013 August	2013 September	2013 October	2013 November	2013 December	2013 Total
123	IV. Balance Sheet (Millions of $)													
124	Total Utility Plant in Service	2,013.27	2,014.57	2,018.96	2,025.29	2,031.25	2,034.08	2,036.69	2,038.22	2,040.49	2,046.15	2,048.32	2,048.69	2,048.69
125	Construction Work in Progress	40.00	40.00	40.00	40.00	40.90	42.11	44.43	46.75	50.29	57.51	64.76	72.20	72.20
126	Total Utility Plant	2,053.27	2,054.57	2,058.96	2,065.29	2,072.15	2,076.19	2,081.12	2,084.97	2,090.79	2,103.66	2,113.09	2,120.89	2,120.89
127	Accum. Provision for Depreciation and Amort.	970.48	973.79	976.13	977.87	979.75	982.63	985.59	988.89	992.09	994.23	997.49	1,001.32	1,001.32
128	NET UTILITY PLANT	1,082.79	1,080.78	1,082.83	1,087.42	1,092.41	1,093.57	1,095.52	1,096.08	1,098.70	1,109.43	1,115.60	1,119.57	1,119.57
129														
130	Non-Utility Property (Net)													
131	Invest. In Assoc. Org - Patronage Capital	3.68	3.68	4.14	4.15	4.15	4.15	4.15	4.15	4.15	4.15	4.15	4.15	4.15
132	Invest. In Assoc. - Other - General Funds	43.84	43.52	43.52	43.52	43.21	43.21	43.21	42.88	42.88	42.88	42.55	42.55	42.55
133	Other Investments	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
134	Special Funds	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05
135	Special Funds (Transition Reserve)	35.03	35.04	35.05	35.05	35.06	35.07	35.08	35.09	35.10	35.11	35.12	35.13	35.13
136	Special Funds (Economic Reserve)	78.16	76.10	74.28	72.96	71.42	69.25	66.92	64.42	61.89	59.74	57.36	54.28	54.28
137	Special Funds (Rural Economic Reserve)	64.50	64.59	64.69	64.79	64.89	64.99	65.09	65.19	65.29	65.39	65.49	65.60	65.60
138	TOTAL OTHER PROP. AND INVESTMENTS	226.27	224.00	222.75	221.55	219.80	217.74	215.52	212.80	210.38	208.34	205.74	202.77	202.77
139														
140	Cash - General Funds	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
141	Cash - Construction Funds - Trustee													
142	Special Deposits	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60
143	Temporary Investments	107.68	110.19	115.83	115.43	103.74	103.72	102.08	96.00	116.23	107.92	97.02	84.63	84.63
144	Accounts Receivable - Sales of Energy (Net)	51.57	47.81	48.82	43.87	45.55	47.44	51.29	50.05	38.09	38.45	38.33	42.17	42.17
145	Accounts Receivable - Other (Net)	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22
146	Fuel Stock	32.22	32.33	32.41	32.27	32.22	32.34	32.45	32.47	32.76	32.97	33.10	33.18	33.18
147	Materials and Supplies - Other	26.24	26.30	26.35	26.41	26.46	26.52	26.58	26.64	26.70	26.76	26.83	26.89	26.89
148	Prepayments	3.60	3.29	2.97	2.66	2.35	2.05	1.76	1.46	1.17	0.87	0.58	4.18	4.18
149	Other Current and Accrued Assets	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71
150	TOTAL CURRENT AND ACCRUED ASSETS	223.83	222.45	228.92	223.18	212.87	214.62	216.70	209.15	217.48	209.51	198.39	193.59	193.59
151														
152	Unamortized Debt Discount & Extraor. Prop. Losses	3.78	5.16	5.13	5.09	5.06	5.03	5.00	4.96	4.93	4.90	4.86	4.83	4.83
153	Regulatory Assets	1.24	1.40	1.50	1.63	1.80	2.08	2.13	6.72	6.58	6.44	6.29	6.15	6.15
154	Other Deferred Debits	2.89	2.87	2.81	2.76	2.75	2.69	2.64	2.62	2.56	2.51	2.47	2.42	2.42
155	Accumulated Deferred Income Taxes	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
156														
157	TOTAL ASSETS AND OTHER DEBITS	1,540.81	1,536.67	1,543.95	1,541.64	1,534.68	1,535.72	1,537.51	1,532.34	1,540.62	1,541.12	1,533.37	1,529.33	1,529.33
158														

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		2013 January	2013 February	2013 March	2013 April	2013 May	2013 June	2013 July	2013 August	2013 September	2013 October	2013 November	2013 December	2013 Total
159														
160	**TOTAL MARGINS & EQUITY**	401.30	404.54	405.09	401.76	395.98	396.94	399.79	402.57	402.35	399.78	400.08	403.96	403.96
161														
162	Long-Term Debt - RUS	210.37	210.37	212.23	212.24	212.24	214.16	214.17	214.17	216.13	216.14	216.14	218.13	218.13
163	Long-Term Debt - Other	714.88	711.06	714.25	714.25	710.39	718.08	718.08	715.08	730.02	730.02	726.99	725.10	725.10
164	**TOTAL LONG-TERM DEBT**	925.25	921.43	926.48	926.49	922.63	932.24	932.25	929.25	946.14	946.16	943.13	943.23	943.23
165														
166	Notes Payable	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
167	Accounts Payable	28.37	26.95	30.61	29.95	33.79	28.31	29.07	28.41	22.93	24.95	22.37	20.18	20.18
168	Accounts Payable (TIER Rebate)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
169	Taxes Accrued	0.55	0.88	1.20	1.53	1.85	2.18	2.50	0.69	1.01	1.34	1.10	0.81	0.81
170	Interest Accrued	5.01	4.68	4.24	6.92	7.00	4.86	5.13	5.25	4.50	7.29	7.40	4.89	4.89
171	Other Current and Accrued Liabilities	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29
172														
173	**TOTAL CURRENT AND ACCRUED LIAB.**	42.23	40.80	44.34	46.69	50.93	43.64	44.99	42.64	36.73	41.87	39.16	34.17	34.17
174														
175	Deferred Credits	3.91	3.68	3.47	3.29	3.10	2.87	2.62	2.36	2.25	2.15	2.04	1.92	1.92
176	Deferred Credits (Economic Reserve)	78.16	76.10	74.28	72.96	71.42	69.25	66.92	64.42	61.89	59.74	57.36	54.28	54.28
177	Deferred Credits (Rural Economic Reserve)	64.50	64.59	64.69	64.79	64.89	64.99	65.09	65.19	65.29	65.39	65.49	65.60	65.60
178	Accumulated Operating Provisions	25.46	25.53	25.59	25.65	25.72	25.78	25.85	25.91	25.98	26.04	26.11	26.17	26.17
179	Obligation under Capital Leases - Noncurrent													
180														
181	**TOTAL LIABILITIES AND OTHER CREDITS**	1,540.81	1,536.67	1,543.95	1,541.64	1,534.68	1,535.72	1,537.51	1,532.34	1,540.62	1,541.12	1,533.37	1,529.33	1,529.33
182														

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		2013 January	2013 February	2013 March	2013 April	2013 May	2013 June	2013 July	2013 August	2013 September	2013 October	2013 November	2013 December	2013 Total
183														
184	**V. Cash Flow Statement (Millions of $)**													
185	Operating Receipts													
186	Rural	11.26	11.02	8.60	6.76	7.62	9.82	10.91	12.44	11.67	9.67	11.02	14.72	125.50
187	Large Industrial	2.95	2.88	2.98	2.93	2.95	2.91	3.16	3.40	3.68	3.76	3.71	3.76	39.06
188	Smelters	31.30	28.44	31.43	30.37	31.42	30.51	31.44	25.12	15.50	15.94	15.40	15.86	302.72
189	Offsystem	[redacted]												
190	Lease Income													
191	Other Operating Revenues	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	3.70
192	Gain on Sale of Allowances	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
193	Other	0.00	0.00	1.24	0.03	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	1.27
194	Interest Earnings	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.16	2.02
195	Total Receipts	[redacted]												
196														
197	Operating Disbursements													
198	PPA													
199	Fuel Costs	[redacted]												
200	Fuel Costs (Labor & Exp)	[redacted]												
201	Domtar	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
202	Power Supply (P Power, APM, Cogen, & TVA Tran)	[redacted]												
203	Production O&M	[redacted]												
204	Transmission O&M	[redacted]												
205	A&G	[redacted]												
206	Working Capital	(0.13)	(3.27)	(2.81)	(4.90)	(3.12)	6.74	2.47	0.61	(7.10)	(2.28)	2.07	9.91	(1.81)
207	Other	0.11	0.16	0.11	0.14	0.17	0.31	0.06	4.59	(0.14)	(0.14)	(0.14)	(0.14)	5.09
208	Total Disbursements	[redacted]												
209														
210	Operating Receipts less Disbursements	8.69	11.16	8.83	7.64	3.14	(1.04)	5.30	2.48	11.82	5.23	3.45	(1.38)	65.33

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		2013 January	2013 February	2013 March	2013 April	2013 May	2013 June	2013 July	2013 August	2013 September	2013 October	2013 November	2013 December	2013 Total
211														
212	Capital Expenditures													
213	Generation	[redacted]												
214	Transmission	0.55	0.85	0.56	0.81	0.63	0.80	0.52	0.49	0.41	0.85	1.58	0.15	8.22
215	A&G	0.02	0.60	0.30	0.58	0.10	0.10	0.10	0.10	0.15	0.20	0.20	0.20	2.64
216	Other / IT	0.05	0.10	0.24	0.48	0.47	0.39	0.31	0.22	0.15	0.11	0.12	0.08	2.68
217	Total Capital Expenditures	[redacted]												
218														
219	Income Taxes from Operations	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
220														
221	Net Pre-Finance Cash Flow	7.47	9.46	3.08	(0.63)	(5.55)	(5.90)	(0.35)	(1.81)	5.35	(9.32)	(6.51)	(9.11)	(13.81)
222														
223	Financing													
224	Principal	0.00	3.83	(3.19)	0.00	3.86	(7.69)	0.00	3.00	(14.94)	0.00	3.03	1.88	(10.22)
225	Interest	3.68	3.81	2.49	1.13	3.85	4.03	3.65	3.82	2.62	1.17	3.76	4.49	38.47
226	Debt Issuance Cost	0.00	1.40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	1.42
227	Line of Credit (Upfront Fee)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
228	Aggregate Debt Service (incl. Line of Credit)	3.68	9.04	(0.70)	1.13	7.71	(3.67)	3.65	6.82	(12.32)	1.17	6.79	6.39	29.67
229														
230	Post-Finance Cash Flow	3.80	0.42	3.79	(1.76)	(13.26)	(2.23)	(4.00)	(8.63)	17.67	(10.49)	(13.30)	(15.51)	(43.49)
231														
232	Unwind Transaction													
233	Cash Proceeds													
234	Debt Reduction													
235	Misc. Transaction													
236	Net Before Member Reserves													
237	Station Two O&M Fund													
238	Rural Economic Reserve	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
239	Economic Reserve	2.47	2.10	1.86	1.36	1.58	2.22	2.37	2.55	2.57	2.18	2.41	3.12	26.80
240	Net Before Transition Reserve	2.47	2.10	1.86	1.36	1.58	2.22	2.37	2.55	2.57	2.18	2.41	3.12	26.80
241														

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		2013 January	2013 February	2013 March	2013 April	2013 May	2013 June	2013 July	2013 August	2013 September	2013 October	2013 November	2013 December	2013 Total
242	Ending Cash Balances (Incl. Transition Reserve)	142.71	145.23	150.88	150.49	138.81	138.80	137.17	131.09	151.33	143.03	132.14	119.76	119.76
243	Ending Cash Balances excl. Transition Reserve)	107.68	110.20	115.84	115.43	103.75	103.73	102.09	96.00	116.23	107.92	97.03	84.63	84.63
244	Change in Working Capital													
245	Other Property	0.00	(0.32)	0.46	0.01	(0.32)	0.00	0.00	(0.32)	0.00	0.00	(0.33)	0.00	(0.81)
246	Accounts Receivable	1.85	(3.76)	1.01	(4.95)	1.68	1.89	3.85	(1.24)	(11.96)	0.36	(0.12)	3.84	(7.55)
247	Materials, Supplies & Other	0.06	0.06	0.06	0.06	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.71
248	Prepayments	(0.59)	(0.30)	(0.30)	(0.30)	(0.30)	(0.30)	(0.30)	(0.30)	(0.30)	(0.30)	(0.30)	3.61	0.06
249	Other Current Assets	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
250	Accounts Payable	(1.05)	1.42	(3.66)	0.66	(3.84)	5.48	(0.75)	0.66	5.48	(2.02)	2.58	2.19	7.14
251	Taxes Accrued	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	1.81	(0.32)	(0.32)	0.24	0.29	(0.58)
252	Other Accruals	(0.06)	(0.06)	(0.06)	(0.06)	(0.06)	(0.06)	(0.06)	(0.06)	(0.06)	(0.06)	(0.07)	(0.07)	(0.77)
253	Total	(0.13)	(3.27)	(2.81)	(4.90)	(3.12)	6.74	2.47	0.61	(7.10)	(2.28)	2.07	9.91	(1.81)
254														

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		2013 January	2013 February	2013 March	2013 April	2013 May	2013 June	2013 July	2013 August	2013 September	2013 October	2013 November	2013 December	2013 Total
255														
256	**VI. Cash Flow Statement - Indirect (Millions of $)**													
257														
258	**Cash Flows From Operating Activities:**													
259	Net Margin	4.02	3.24	0.55	(3.33)	(5.78)	0.96	2.85	2.78	(0.22)	(2.57)	0.31	3.88	6.68
260	Adjustments to reconcile net margin to net cash													
261	provided by operating activities:													
262	Depreciation and amortization	3.71	3.71	3.72	3.73	3.75	3.76	3.77	3.77	3.91	3.92	3.93	3.93	45.61
263	Interest compounded - RUS Series A Note	0.01	0.00	0.00	0.01	0.00	0.00	0.01	0.00	0.00	0.01	0.00	0.00	0.04
264	Interest compounded - RUS Series B Note	0.00	0.00	1.86	0.00	0.00	1.91	0.00	0.00	1.96	0.00	0.00	1.99	7.72
265	Noncash member rate mitigation revenue	(2.83)	(2.48)	(2.17)	(1.68)	(1.94)	(2.73)	(2.68)	(7.39)	(2.54)	(2.15)	(2.38)	(3.09)	(34.05)
266	Changes in certain assets and liabilities:													
267	Other property	0.00	0.32	(0.46)	(0.01)	0.32	0.00	0.00	0.32	0.00	0.00	0.33	0.00	0.81
268	Accounts receivable	(1.85)	3.76	(1.01)	4.95	(1.68)	(1.89)	(3.85)	1.24	11.96	(0.36)	0.12	(3.84)	7.55
269	Inventories	(0.28)	(0.17)	(0.13)	0.08	(0.01)	(0.18)	(0.17)	(0.08)	(0.35)	(0.27)	(0.20)	(0.14)	(1.89)
270	Prepayments	0.61	0.31	0.31	0.31	0.31	0.30	0.30	0.30	0.30	0.30	0.30	(3.61)	0.03
271	Other current assets	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
272	Accounts payable	1.05	(1.42)	3.66	(0.66)	3.84	(5.48)	0.75	(0.66)	(5.48)	2.02	(2.58)	(2.19)	(7.14)
273	Taxes accrued	0.32	0.32	0.32	0.32	0.32	0.32	0.32	(1.81)	0.32	0.32	(0.24)	(0.29)	0.58
274	Other accruals	0.23	(0.23)	(0.30)	2.78	0.15	(2.05)	0.34	0.20	(0.66)	2.84	0.11	(2.52)	0.90
275	Net cash provided by operating activities	5.02	7.35	6.34	6.51	(0.71)	(5.07)	1.65	(1.33)	9.20	4.06	(0.31)	(5.87)	26.85
276														
277	**Cash Flows From Investing Activities:**													
278	Capital expenditures	(1.22)	(1.70)	(5.75)	(8.27)	(8.69)	(4.86)	(5.65)	(4.29)	(6.47)	(14.55)	(9.96)	(7.73)	(79.14)
279	Net proceeds from restricted investments	2.46	2.09	1.85	1.35	1.58	2.21	2.36	2.54	2.56	2.18	2.40	3.11	26.70
280	Net cash provided by (used in) inv. Activities	1.24	0.39	(3.89)	(6.91)	(7.12)	(2.65)	(3.29)	(1.75)	(3.91)	(12.37)	(7.56)	(4.62)	(52.44)

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281														
282	**Cash Flows From Financing Activities:**													
283	Net principal payments on debt obligations	0.00	(3.83)	3.19	0.00	(3.86)	7.69	0.00	(3.00)	14.94	0.00	(3.03)	(1.88)	10.22
284	Debt issuance cost	0.00	(1.40)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.02)	(1.42)
285	Line of Credit (Upfront Fee)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
286	Net cash provided by (used in) Financihng Activities	0.00	(5.23)	3.19	0.00	(3.86)	7.69	0.00	(3.00)	14.94	0.00	(3.03)	(1.90)	8.80
287														
288	Net increase (decrease) in cash	6.26	2.51	5.64	(0.41)	(11.68)	(0.02)	(1.64)	(6.09)	20.23	(8.31)	(10.89)	(12.40)	(16.79)
289														
290	**Cash and Cash Equivalents - Beg. of Period**													101.42
291	**Cash and Cash Equivalents - End of Period**													84.63

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		2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	2014 September	2014 October	2014 November	2014 December	2014 Total
1														
2	**I. Sales**													
3														
4	**Energy (TWH)**													
5	Rural	0.25	0.21	0.19	0.15	0.17	0.22	0.25	0.24	0.18	0.16	0.18	0.25	2.45
6	Large Industrial	0.08	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.94
7	Century	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	Alcan	0.27	0.24	0.27	0.26	0.27	0.26	0.27	0.27	0.26	0.27	0.26	0.27	3.16
9	Market	[redacted]												
10	Total Energy Sales	0.77	0.69	0.66	0.60	0.63	0.68	0.71	0.71	0.68	0.74	0.72	0.74	8.32
11														
12	**Demand (MW)**													
13	Rural	548.56	489.60	425.32	333.27	380.07	479.13	500.79	541.33	422.41	341.34	383.06	502.06	5,346.95
14	Large Industrial	140.57	139.90	139.11	139.40	138.43	138.53	143.19	143.54	136.42	138.47	138.43	138.60	1,674.59
15														
16	**II. Rates, Accrual Based ($ / MWH)**													
17														
18	**Rural**													
19	Load Factor (%)	62.04%	64.25%	60.26%	62.62%	59.36%	63.85%	66.35%	59.09%	59.77%	61.61%	66.05%	66.80%	62.74%
20	Demand ($/ KW-mo.)	16.85	16.85	16.85	16.85	16.85	16.85	16.85	16.85	16.85	16.85	16.85	16.85	16.85
21	Energy ($/ MWH)	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00
22	Base Rate ($/ MWH)	66.50	69.02	67.58	67.37	68.15	66.65	64.13	68.33	69.15	66.76	65.43	63.90	66.79
23														
24	Non-Smelter Non-FAC PPA	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.33)	(0.33)	(0.33)	(0.33)	(0.64)
25	FAC	4.90	5.07	5.22	5.34	5.44	5.64	5.66	5.70	5.77	5.38	5.43	5.44	5.41
26	Environmental Surcharge	3.72	3.88	3.67	3.98	3.94	3.87	3.70	4.55	5.37	5.11	4.66	4.23	4.19
27	Surcredit	(1.50)	(1.64)	(1.84)	(2.15)	(2.02)	(1.64)	(1.51)	(1.56)	(1.89)	(2.12)	(1.89)	(1.52)	(1.73)
28	Total	7.13	7.31	7.05	7.18	7.36	7.87	7.85	8.69	9.24	8.38	8.20	8.15	7.87
29	Economic Reserve	(10.34)	(10.53)	(10.26)	(10.39)	(10.57)	(11.08)	(9.06)	(9.90)	(10.46)	(9.59)	(9.41)	(9.36)	(10.06)
30	Rural Economic Reserve	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
31	TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
32	Effective Rate ($/ MWH)	62.51	65.03	63.59	63.37	64.15	62.65	62.14	66.33	67.61	65.21	63.89	62.36	63.96
33														

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34	**Large Industrial**													
35	Load Factor (%)	75.71%	79.04%	77.68%	76.94%	76.72%	77.06%	77.88%	76.94%	78.20%	76.55%	77.18%	76.59%	77.20%
36	Demand ($/ KW-mo.)	12.33	12.33	12.33	12.33	12.33	12.33	12.33	12.33	12.33	12.33	12.33	12.33	12.33
37	Energy ($/ MWH)	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00
38	Power Factor Penalty/ Demand Cr. (Lrg. Ind.)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
39	Base Rate ($/ MWH)	51.89	53.21	51.34	52.26	51.60	52.22	51.28	51.54	51.90	51.65	52.19	51.64	51.88
40														
41	Non-Smelter Non-FAC PPA	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.33)	(0.33)	(0.33)	(0.33)	(0.63)
42	FAC	4.90	5.07	5.22	5.34	5.44	5.64	5.66	5.70	5.77	5.38	5.43	5.44	5.42
43	Environmental Surcharge	2.96	3.05	2.85	3.16	3.05	3.10	3.02	3.52	4.12	4.04	3.78	3.48	3.34
44	Surcredit	(1.50)	(1.64)	(1.84)	(2.15)	(2.02)	(1.64)	(1.51)	(1.56)	(1.89)	(2.12)	(1.89)	(1.52)	(1.77)
45	Total	6.37	6.49	6.23	6.35	6.48	7.09	7.17	7.66	8.00	7.30	7.33	7.40	6.99
46	Economic Reserve	(9.58)	(9.70)	(9.44)	(9.56)	(9.69)	(10.31)	(8.38)	(8.87)	(9.21)	(8.51)	(8.54)	(8.61)	(9.19)
47	TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
48	Effective Rate ($/ MWH)	47.90	49.22	47.34	48.26	47.61	48.23	49.29	49.55	50.36	50.11	50.65	50.10	49.05
49														
50	**Non-Smelter Member Blend**													
51	Base Rate ($/ MWH)	63.02	64.91	62.76	62.24	62.85	62.92	60.90	64.02	64.02	61.69	61.50	60.95	62.64
52														
53	Non-Smelter Non-FAC PPA	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.33)	(0.33)	(0.33)	(0.33)	(0.64)
54	FAC	4.90	5.07	5.22	5.34	5.44	5.64	5.66	5.70	5.77	5.38	5.43	5.44	5.42
55	Environmental Surcharge	3.54	3.66	3.43	3.70	3.66	3.67	3.53	4.29	5.00	4.75	4.40	4.05	3.95
56	Surcredit	(1.50)	(1.64)	(1.84)	(2.15)	(2.02)	(1.64)	(1.51)	(1.56)	(1.89)	(2.12)	(1.89)	(1.52)	(1.74)
57	Total	6.95	7.10	6.81	6.90	7.08	7.67	7.68	8.42	8.87	8.02	7.94	7.97	7.62
58	Economic Reserve	(10.16)	(10.31)	(10.02)	(10.11)	(10.29)	(10.88)	(8.89)	(9.64)	(10.09)	(9.23)	(9.15)	(9.18)	(9.82)
59	Rural Economic Reserve	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
60	TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61	Effective Rate ($/ MWH)	59.03	60.92	58.77	58.24	58.86	58.92	58.91	62.02	62.48	60.15	59.96	59.41	59.81
62														

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		2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	2014 September	2014 October	2014 November	2014 December	2014 Total
63	**Smelters**													
64	Base Rate	47.49	47.49	47.49	47.49	47.49	47.49	47.49	47.49	47.49	47.49	47.49	47.49	47.49
65	TIER Adjustment	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.95
66	Total	50.44	50.44	50.44	50.44	50.44	50.44	50.44	50.44	50.44	50.44	50.44	50.44	50.44
67	Non-FAC PPA	(0.41)	(0.35)	(0.36)	(0.31)	(0.34)	(0.38)	(0.41)	(0.40)	(0.34)	(0.32)	(0.34)	(0.41)	(0.36)
68	FAC	4.90	5.07	5.22	5.34	5.44	5.64	5.66	5.70	5.77	5.38	5.43	5.44	5.42
69	Environmental Surcharge	2.70	2.72	2.63	2.86	2.80	2.81	2.78	3.23	3.79	3.72	3.46	3.20	3.06
70	Surcharge	1.86	1.93	1.86	1.88	1.86	1.88	1.86	1.86	1.88	1.86	1.88	1.86	1.87
71	TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
72	Effective Rate ($/ MWH)	59.48	59.81	59.78	60.21	60.20	60.39	60.32	60.82	61.53	61.08	60.86	60.53	60.42
73														
74	Market	34.60	33.68	31.84	31.93	29.94	32.48	36.22	33.82	29.16	28.94	29.11	32.04	31.69

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75														
76	**III. Statement of Operations (Millions of $)**													
77														
78	Electric Energy Revenues	[redacted]												
79	Income From Leased Property Net													
80	Other Operating Revenue and Income	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	3.70
81	**TOTAL OPER. REVENUES & PAT. CAPITAL**	[redacted]												
82														
83	Operating Expense-Production-Excluding Fuel	[redacted]												
84	Operating Expense-Production-Fuel	[redacted]												
85	Operating Expense-Other Power Supply	[redacted]												
86	Operating Expense-Transmission	[redacted]												
87	Operating Expense-RTO/ISO	[redacted]												
88	Operating Expense-Distribution	[redacted]												
89	Operating Expense-Customer Accounts	[redacted]												
90	Operating Expense-Customer Service and Information	[redacted]												
91	Operating Expense-Sales	[redacted]												
92	Operating Expense-Administrative and General	[redacted]												
93	**TOTAL OPERATION EXPENSE**	[redacted]												
94														
95	Maintenance Expense-Production	[redacted]												
96	Maintenance Expense-Transmission	[redacted]												
97	Maintenance Expense-Distribution	[redacted]												
98	Maintenance Expense-General Plant	[redacted]												
99	**TOTAL MAINTENANCE EXPENSE**	[redacted]												
100														

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		2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	2014 September	2014 October	2014 November	2014 December	2014 Total
101	Depreciation and Amortization Expense	3.66	3.66	3.66	3.67	3.69	3.70	3.70	3.71	3.83	3.84	3.85	3.85	44.82
102	Taxes	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
103	Interest on Long-Term Debt	3.91	3.66	3.98	3.90	4.01	3.88	4.01	4.01	3.89	4.01	3.90	4.00	47.16
104	Interest Charged to Construction - Credit	(0.17)	(0.19)	(0.22)	(0.29)	(0.34)	(0.38)	(0.39)	(0.01)	(0.02)	(0.04)	(0.02)	(0.02)	(2.10)
105	Other Interest Expense	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
106	Asset Retirement Obligation													
107	Other Deductions	0.05	0.05	0.05	0.05	0.04	0.06	0.04	0.04	0.04	0.05	0.05	0.07	0.59
108														
109	**TOTAL COST OF ELECTRIC SERVICE**	[redacted]												
110														
111	**OPERATING MARGINS**	4.90	3.30	(2.31)	(6.88)	(4.46)	1.67	3.48	3.36	0.36	(1.99)	0.87	3.58	5.87
112														
113	Interest Income	0.17	0.17	0.17	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	1.95
114	Allowance For Funds Used During Construction													
115	Income (Loss) From Equity Investments													
116	Other Non-Operating Income (Net)													
117	Generation and Transmission Capital Credits													
118	Other Capital Credits and Patronage Dividends	0.00	0.00	2.71	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.71
119	Extraordinary Items													
120	**NET PATRONAGE CAPITAL OR MARGIN**	5.06	3.46	0.56	(6.72)	(4.29)	1.83	3.64	3.52	0.52	(1.83)	1.03	3.74	10.53
121														
122														

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		2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	2014 September	2014 October	2014 November	2014 December	2014 Total
123	**IV. Balance Sheet (Millions of $)**													
124	Total Utility Plant in Service	2,049.94	2,050.62	2,053.81	2,065.17	2,072.74	2,074.16	2,075.48	2,139.74	2,142.64	2,145.96	2,146.14	2,146.25	2,146.25
125	Construction Work in Progress	77.36	82.55	87.83	93.13	98.46	101.21	101.50	40.00	40.00	40.00	40.00	40.00	40.00
126	Total Utility Plant	2,127.30	2,133.18	2,141.64	2,158.31	2,171.20	2,175.37	2,176.98	2,179.74	2,182.64	2,185.96	2,186.14	2,186.25	2,186.25
127	Accum. Provision for Depreciation and Amort.	1,004.86	1,008.59	1,011.52	1,011.90	1,013.51	1,017.09	1,020.70	1,023.83	1,027.05	1,030.15	1,034.24	1,038.35	1,038.35
128	NET UTILITY PLANT	1,122.44	1,124.59	1,130.12	1,146.41	1,157.69	1,158.28	1,156.28	1,155.91	1,155.58	1,155.81	1,151.89	1,147.90	1,147.90
129														
130	Non-Utility Property (Net)													
131	Invest. In Assoc. Org - Patronage Capital	4.15	4.15	4.32	4.32	4.32	4.32	4.32	4.32	4.32	4.32	4.32	4.32	4.32
132	Invest. In Assoc. - Other - General Funds	42.55	42.22	42.22	42.22	41.89	41.89	41.89	41.54	41.54	41.54	41.20	41.20	41.20
133	Other Investments	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
134	Special Funds	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05
135	Special Funds (Transition Reserve)	35.13	35.14	35.15	35.16	35.17	35.18	35.19	35.20	35.20	35.21	35.22	35.23	35.23
136	Special Funds (Economic Reserve)	50.94	48.02	45.33	43.06	40.54	37.34	34.42	31.36	28.77	26.62	24.26	21.26	21.26
137	Special Funds (Rural Economic Reserve)	65.70	65.79	65.89	65.99	66.10	66.20	66.30	66.40	66.50	66.61	66.71	66.81	66.81
138	TOTAL OTHER PROP. AND INVESTMENTS	199.54	196.39	193.98	191.81	189.07	185.97	183.18	179.88	177.40	175.36	172.77	169.88	169.88
139														
140	Cash - General Funds	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
141	Cash - Construction Funds - Trustee													
142	Special Deposits	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60
143	Temporary Investments	96.50	98.34	107.96	93.87	73.78	70.15	74.43	74.09	81.87	85.24	85.46	81.73	81.73
144	Accounts Receivable - Sales of Energy (Net)	44.71	40.14	38.51	34.77	36.54	40.56	42.67	43.39	39.37	39.62	39.47	43.32	43.32
145	Accounts Receivable - Other (Net)	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22
146	Fuel Stock	33.56	33.78	34.02	34.08	34.03	34.09	34.14	34.16	34.19	34.22	34.24	34.24	34.24
147	Materials and Supplies - Other	26.96	27.02	27.09	27.15	27.22	27.28	27.35	27.41	27.48	27.55	27.61	27.68	27.68
148	Prepayments	3.86	3.53	3.21	2.88	2.56	2.23	1.91	1.58	1.26	0.93	0.61	4.38	4.38
149	Other Current and Accrued Assets	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71
150	TOTAL CURRENT AND ACCRUED ASSETS	208.12	205.35	213.32	195.29	176.66	176.85	183.02	183.16	186.70	190.09	189.92	193.88	193.88
151														
152	Unamortized Debt Discount & Extraor. Prop. Losses	4.80	4.77	4.73	4.70	4.67	4.63	4.60	4.57	4.54	4.50	4.47	4.44	4.44
153	Regulatory Assets	6.01	5.87	5.73	5.58	5.44	5.30	5.16	5.02	4.87	4.73	4.59	4.45	4.45
154	Other Deferred Debits	2.37	2.36	2.29	2.24	2.23	2.17	2.25	2.23	2.16	2.12	2.08	2.03	2.03
155	Accumulated Deferred Income Taxes	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
156														
157	TOTAL ASSETS AND OTHER DEBITS	1,543.28	1,539.32	1,550.17	1,546.04	1,535.76	1,533.22	1,534.49	1,530.77	1,531.26	1,532.61	1,525.72	1,522.57	1,522.57
158														

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159														
160	**TOTAL MARGINS & EQUITY**	409.02	412.49	413.05	406.33	402.04	403.87	407.51	411.02	411.55	409.71	410.75	414.49	414.49
161														
162	Long-Term Debt - RUS	218.14	218.14	220.11	220.12	220.12	222.15	222.16	222.16	224.24	224.25	224.25	226.36	226.36
163	Long-Term Debt - Other	734.10	731.05	738.14	738.14	735.06	737.25	737.25	734.15	735.83	735.83	732.71	730.73	730.73
164	**TOTAL LONG-TERM DEBT**	952.24	949.19	958.26	958.27	955.19	959.40	959.41	956.31	960.07	960.08	956.96	957.09	957.09
165														
166	Notes Payable	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
167	Accounts Payable	23.37	21.56	25.68	27.36	26.29	23.22	23.01	23.53	22.83	24.80	22.23	20.93	20.93
168	Accounts Payable (TIER Rebate)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
169	Taxes Accrued	0.58	0.93	1.28	1.63	1.98	2.33	2.68	0.75	1.10	1.46	1.17	0.96	0.96
170	Interest Accrued	5.11	5.08	4.46	7.21	7.48	4.79	5.13	5.42	4.40	7.23	7.48	4.76	4.76
171	Other Current and Accrued Liabilities	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29
172														
173	**TOTAL CURRENT AND ACCRUED LIAB.**	37.35	35.86	39.71	44.50	44.05	38.63	39.12	37.99	36.62	41.77	39.17	34.95	34.95
174														
175	Deferred Credits	1.80	1.68	1.56	1.45	1.34	1.22	1.10	0.98	0.98	0.98	0.99	1.01	1.01
176	Deferred Credits (Economic Reserve)	50.94	48.02	45.33	43.06	40.54	37.34	34.42	31.36	28.77	26.62	24.26	21.26	21.26
177	Deferred Credits (Rural Economic Reserve)	65.70	65.79	65.89	65.99	66.10	66.20	66.30	66.40	66.50	66.61	66.71	66.81	66.81
178	Accumulated Operating Provisions	26.24	26.30	26.37	26.44	26.50	26.57	26.63	26.70	26.77	26.83	26.90	26.97	26.97
179	Obligation under Capital Leases - Noncurrent													
180														
181	**TOTAL LIABILITIES AND OTHER CREDITS**	1,543.28	1,539.32	1,550.17	1,546.04	1,535.76	1,533.22	1,534.49	1,530.77	1,531.26	1,532.61	1,525.72	1,522.57	1,522.57
182														

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183														
184	**V. Cash Flow Statement (Millions of $)**													
185	Operating Receipts													
186	Rural	15.83	13.75	12.13	9.52	10.77	13.80	15.36	15.79	12.29	10.20	11.64	15.56	156.63
187	Large Industrial	3.79	3.66	3.81	3.73	3.76	3.71	4.09	4.07	3.87	3.95	3.90	3.96	46.28
188	Smelters	15.96	14.49	16.04	15.64	16.15	15.68	16.19	16.32	15.98	16.39	15.80	16.24	190.87
189	Offsystem	[redacted]												
190	Lease Income	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	3.70
191	Other Operating Revenues	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
192	Gain on Sale of Allowances	0.00	0.00	2.71	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.71
193	Other	0.17	0.17	0.17	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	1.95
194	Interest Earnings	[redacted]												
195	Total Receipts	[redacted]												
196														
197	Operating Disbursements													
198	PPA	[redacted]												
199	Fuel Costs	[redacted]												
200	Fuel Costs (Labor & Exp)	[redacted]												
201	Domtar	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
202	Power Supply (P Power, APM, Cogen, & TVA Tran)	[redacted]												
203	Production O&M	[redacted]												
204	Transmission O&M	[redacted]												
205	A&G	[redacted]												
206	Working Capital	(0.73)	(3.77)	(6.26)	(6.11)	1.83	6.42	1.64	1.46	(3.99)	(2.40)	2.03	9.12	(0.76)
207	Other	(0.13)	(0.14)	(0.14)	(0.14)	(0.14)	(0.12)	(0.14)	(0.14)	(0.14)	(0.14)	(0.14)	(0.14)	(1.62)
208	Total Disbursements	[redacted]												
209														
210	Operating Receipts less Disbursements	9.82	11.55	11.70	4.71	(0.90)	(0.29)	6.73	7.02	10.11	6.69	4.85	0.00	72.00

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		2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	2014 September	2014 October	2014 November	2014 December	2014 Total
211														
212	Capital Expenditures													
213	Generation	[redacted]												
214	Transmission	0.22	0.33	0.33	0.39	0.38	0.33	0.17	0.36	0.88	0.61	0.18	0.10	4.30
215	A&G	0.00	0.21	0.10	0.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.55
216	Other / IT	0.00	0.05	0.10	0.31	0.11	0.26	0.22	0.32	0.23	0.04	0.01	0.00	1.64
217	Total Capital Expenditures	[redacted]												
218														
219	Income Taxes from Operations	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
220														
221	Net Pre-Finance Cash Flow	3.19	5.65	2.45	(15.25)	(15.81)	(4.49)	5.13	3.40	6.34	2.37	4.64	(0.13)	(2.51)
222														
223	Financing													
224	Principal	(9.00)	3.05	(7.09)	0.00	3.08	(2.19)	0.00	3.10	(1.69)	0.00	3.13	1.98	(5.63)
225	Interest	3.68	3.70	2.63	1.13	3.74	4.55	3.65	3.71	2.84	1.17	3.65	4.61	39.06
226	Debt Issuance Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.02
227	Line of Credit (Upfront Fee)	0.00	0.00	0.00	0.00	0.00	0.00	0.13	0.00	0.00	0.00	0.00	0.00	0.13
228	Aggregate Debt Service (incl. Line of Credit)	(5.32)	6.75	(4.46)	1.13	6.82	2.36	3.78	6.82	1.15	1.17	6.78	6.61	33.58
229														
230	Post-Finance Cash Flow	8.51	(1.10)	6.91	(16.37)	(22.63)	(6.85)	1.35	(3.41)	5.19	1.20	(2.14)	(6.73)	(36.09)
231														
232	Unwind Transaction													
233	Cash Proceeds													
234	Debt Reduction													
235	Misc. Transaction													
236	Net Before Member Reserves													
237	Station Two O&M Fund													
238	Rural Economic Reserve	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
239	Economic Reserve	3.38	2.95	2.72	2.30	2.54	3.23	2.93	3.08	2.61	2.17	2.37	3.02	33.30
240	Net Before Transition Reserve	3.38	2.95	2.72	2.30	2.54	3.23	2.93	3.08	2.61	2.17	2.37	3.02	33.30
241														

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		2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	2014 September	2014 October	2014 November	2014 December	2014 Total
242	Ending Cash Balances (Incl. Transition Reserve)	131.64	133.49	143.11	129.04	108.95	105.33	109.62	109.29	117.08	120.45	120.69	116.97	116.97
243	Ending Cash Balances excl. Transition Reserve)	96.51	98.35	107.96	93.88	73.78	70.15	74.43	74.09	81.88	85.24	85.46	81.74	81.74
244	Change in Working Capital													
245	Other Property	0.00	(0.33)	0.16	0.00	(0.34)	0.00	0.00	(0.34)	0.00	0.00	(0.35)	0.00	(1.19)
246	Accounts Receivable	2.55	(4.57)	(1.63)	(3.75)	1.77	4.02	2.11	0.72	(4.02)	0.25	(0.15)	3.85	1.15
247	Materials, Supplies & Other	0.06	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.79
248	Prepayments	(0.33)	(0.33)	(0.33)	(0.33)	(0.33)	(0.33)	(0.33)	(0.33)	(0.33)	(0.33)	(0.33)	3.77	0.20
249	Other Current Assets	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
250	Accounts Payable	(3.18)	1.81	(4.12)	(1.68)	1.07	3.07	0.21	(0.51)	0.70	(1.97)	2.57	1.30	(0.75)
251	Taxes Accrued	0.23	(0.35)	(0.35)	(0.35)	(0.35)	(0.35)	(0.35)	1.93	(0.35)	(0.35)	0.29	0.21	(0.15)
252	Other Accruals	(0.07)	(0.07)	(0.07)	(0.07)	(0.07)	(0.07)	(0.07)	(0.07)	(0.07)	(0.07)	(0.07)	(0.07)	(0.80)
253	Total	(0.73)	(3.77)	(6.26)	(6.11)	1.83	6.42	1.64	1.46	(3.99)	(2.40)	2.03	9.12	(0.76)
254														

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Witness: Travis A. Siewert

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		2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	2014 September	2014 October	2014 November	2014 December	2014 Total
255														
256	**VI. Cash Flow Statement - Indirect (Millions of $)**													
257														
258	**Cash Flows From Operating Activities:**													
259	Net Margin	5.06	3.46	0.56	(6.72)	(4.29)	1.83	3.64	3.52	0.52	(1.83)	1.03	3.74	10.53
260	Adjustments to reconcile net margin to net cash													
261	provided by operating activities:													
262	Depreciation and amortization	3.94	3.94	3.94	3.95	3.97	3.99	4.00	4.00	4.13	4.13	4.14	4.14	48.28
263	Interest compounded - RUS Series A Note	0.01	0.00	0.00	0.01	0.00	0.00	0.01	0.00	0.00	0.01	0.00	0.00	0.05
264	Interest compounded - RUS Series B Note	0.00	0.00	1.97	0.00	0.00	2.02	0.00	0.00	2.08	0.00	0.00	2.11	8.18
265	Noncash member rate mitigation revenue	(3.36)	(2.93)	(2.69)	(2.27)	(2.51)	(3.21)	(2.91)	(3.06)	(2.46)	(2.03)	(2.23)	(2.85)	(32.50)
266	Changes in certain assets and liabilities:													
267	Other property	0.00	0.33	(0.16)	0.00	0.34	0.00	0.00	0.34	0.00	0.00	0.35	0.00	1.19
268	Accounts receivable	(2.55)	4.57	1.63	3.75	(1.77)	(4.02)	(2.11)	(0.72)	4.02	(0.25)	0.15	(3.85)	(1.15)
269	Inventories	(0.44)	(0.29)	(0.30)	(0.12)	(0.02)	(0.13)	(0.11)	(0.09)	(0.09)	(0.10)	(0.08)	(0.07)	(1.84)
270	Prepayments	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	(3.77)	(0.20)
271	Other current assets	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
272	Accounts payable	3.18	(1.81)	4.12	1.68	(1.07)	(3.07)	(0.21)	0.51	(0.70)	1.97	(2.57)	(1.30)	0.75
273	Taxes accrued	(0.23)	0.35	0.35	0.35	0.35	0.35	0.35	(1.93)	0.35	0.35	(0.29)	(0.21)	0.15
274	Other accruals	0.20	(0.11)	(0.68)	2.62	0.04	(2.93)	0.10	0.40	(0.89)	2.94	0.37	(2.56)	(0.50)
275	Net cash provided by operating activities	6.14	7.85	9.07	3.58	(4.64)	(4.84)	3.08	3.31	7.27	5.52	1.20	(4.61)	32.93
276														
277	**Cash Flows From Investing Activities:**													
278	Capital expenditures	(6.64)	(5.90)	(9.25)	(19.95)	(14.91)	(4.20)	(1.60)	(3.62)	(3.77)	(4.32)	(0.21)	(0.13)	(74.50)
279	Net proceeds from restricted investments	3.37	2.94	2.71	2.29	2.53	3.22	2.93	3.08	2.60	2.16	2.36	3.01	33.19
280	Net cash provided by (used in) inv. Activities	(3.27)	(2.96)	(6.54)	(17.66)	(12.38)	(0.98)	1.32	(0.54)	(1.18)	(2.16)	2.15	2.88	(41.31)

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		2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	2014 September	2014 October	2014 November	2014 December	2014 Total
281														
282	**Cash Flows From Financing Activities:**													
283	Net pnncipal payments on debt obligations	9.00	(3.05)	7.09	0.00	(3.08)	2.19	0.00	(3.10)	1.69	0.00	(3.13)	(1.98)	5.63
284	Debt issuance cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.02)	(0.02)
285	Line of Credit (Upfront Fee)	0.00	0.00	0.00	0.00	0.00	0.00	(0.13)	0.00	0.00	0.00	0.00	0.00	(0.13)
286	Net cash provided by (used in) Financihng Activities	9.00	(3.05)	7.09	0.00	(3.08)	2.19	(0.13)	(3.10)	1.69	0.00	(3.13)	(2.00)	5.48
287														
288	Net increase (decrease) in cash	11.88	1.84	9.62	(14.08)	(20.10)	(3.63)	4.28	(0.34)	7.79	3.36	0.22	(3.73)	(2.89)
289														
290	**Cash and Cash Equivalents - Beg. of Period**													84.63
291	**Cash and Cash Equivalents - End of Period**													81.74

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#		2013 September	2013 October	2013 November	2013 December	2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	Test Period Total
1														
2	**I. Sales**													
3														
4	**Energy (TWH)**													
5	Rural	0.18	0.15	0.18	0.25	0.25	0.21	0.19	0.15	0.17	0.22	0.25	0.24	2.44
6	Large Industrial	0.08	0.08	0.08	0.08	0.08	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.94
7	Century	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	Alcan	0.26	0.27	0.26	0.27	0.27	0.24	0.27	0.26	0.27	0.26	0.27	0.27	3.16
9	Market	[redacted]												
10	Total Energy Sales	0.68	0.75	0.72	0.75	0.77	0.69	0.66	0.60	0.63	0.68	0.71	0.71	8.34
11														
12	**Demand (MW)**													
13	Rural	416.26	336.41	377.17	494.38	548.56	489.60	425.32	333.27	380.07	479.13	500.79	541.33	5,322.30
14	Large Industrial	136.42	138.47	138.43	138.60	140.57	139.90	139.11	139.40	138.43	138.53	143.19	143.54	1,674.59
15														
16	**II. Rates, Accrual Based ($ / MWH)**													
17														
18	**Rural**													
19	Load Factor (%)	59.69%	61.52%	66.01%	66.76%	62.04%	64.25%	60.26%	62.62%	59.36%	63.85%	66.35%	59.09%	62.82%
20	Demand ($/ KW-mo.)	16.85	16.85	16.85	16.85	16.85	16.85	16.85	16.85	16.85	16.85	16.85	16.85	16.85
21	Energy ($/ MWH)	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00
22	Base Rate ($/ MWH)	69.20	66.81	65.45	63.92	66.50	69.02	67.58	67.37	68.15	66.65	64.13	68.33	66.80
23														
24	Non-Smelter Non-FAC PPA	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)
25	FAC	4.70	4.48	4.61	4.67	4.90	5.07	5.22	5.34	5.44	5.64	5.66	5.70	5.14
26	Environmental Surcharge	4.35	4.13	3.71	3.42	3.72	3.88	3.67	3.98	3.94	3.87	3.70	4.55	3.89
27	Surcredit	(1.91)	(2.14)	(1.91)	(1.54)	(1.50)	(1.64)	(1.84)	(2.15)	(2.02)	(1.64)	(1.51)	(1.56)	(1.74)
28	Total	7.14	6.47	6.41	6.55	7.13	7.31	7.05	7.18	7.36	7.87	7.85	8.69	7.30
29	Economic Reserve	(10.35)	(9.68)	(9.63)	(9.76)	(10.34)	(10.53)	(10.26)	(10.39)	(10.57)	(11.08)	(9.06)	(9.90)	(10.11)
30	Rural Economic Reserve	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
31	TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
32	Effective Rate ($/ MWH)	65.21	62.82	61.45	59.93	62.51	65.03	63.59	63.37	64.15	62.65	62.14	66.33	63.21
33														

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		2013 September	2013 October	2013 November	2013 December	2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	Test Period Total
34	**Large Industrial**													
35	Load Factor (%)	78.20%	76.55%	77.18%	76.59%	75.71%	79.04%	77.68%	76.94%	76.72%	77.06%	77.88%	76.94%	77.20%
36	Demand ($/ KW-mo.)	12.33	12.33	12.33	12.33	12.33	12.33	12.33	12.33	12.33	12.33	12.33	12.33	12.33
37	Energy ($/ MWH)	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00
38	Power Factor Penalty/ Demand Cr. (Lrg. Ind.)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
39	Base Rate ($/ MWH)	51.90	51.65	52.19	51.64	51.89	53.21	51.34	52.26	51.60	52.22	51.28	51.54	51.88
40														
41	Non-Smelter Non-FAC PPA	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)
42	FAC	4.70	4.48	4.61	4.67	4.90	5.07	5.22	5.34	5.44	5.64	5.66	5.70	5.12
43	Environmental Surcharge	3.33	3.25	3.01	2.80	2.96	3.05	2.85	3.16	3.05	3.10	3.02	3.52	3.09
44	Surcredit	(1.91)	(2.14)	(1.91)	(1.54)	(1.50)	(1.64)	(1.84)	(2.15)	(2.02)	(1.64)	(1.51)	(1.56)	(1.78)
45	Total	6.12	5.59	5.71	5.94	6.37	6.49	6.23	6.35	6.48	7.09	7.17	7.66	6.44
46	Economic Reserve	(9.33)	(8.80)	(8.92)	(9.15)	(9.58)	(9.70)	(9.44)	(9.56)	(9.69)	(10.31)	(8.38)	(8.87)	(9.30)
47	TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
48	Effective Rate ($/ MWH)	47.91	47.65	48.20	47.64	47.90	49.22	47.34	48.26	47.61	48.23	49.29	49.55	48.24
49														
50	**Non-Smelter Member Blend**													
51	Base Rate ($/ MWH)	64.01	61.67	61.47	60.93	63.02	64.91	62.76	62.24	62.85	62.92	60.90	64.02	62.64
52														
53	Non-Smelter Non-FAC PPA	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)	(0.78)
54	FAC	4.70	4.48	4.61	4.67	4.90	5.07	5.22	5.34	5.44	5.64	5.66	5.70	5.14
55	Environmental Surcharge	4.04	3.83	3.50	3.27	3.54	3.66	3.43	3.70	3.66	3.67	3.53	4.29	3.67
56	Surcredit	(1.91)	(2.14)	(1.91)	(1.54)	(1.50)	(1.64)	(1.84)	(2.15)	(2.02)	(1.64)	(1.51)	(1.56)	(1.75)
57	Total	6.83	6.17	6.20	6.40	6.95	7.10	6.81	6.90	7.08	7.67	7.68	8.42	7.06
58	Economic Reserve	(10.04)	(9.38)	(9.41)	(9.61)	(10.16)	(10.31)	(10.02)	(10.11)	(10.29)	(10.86)	(8.89)	(9.64)	(9.88)
59	Rural Economic Reserve	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
60	TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61	Effective Rate ($/ MWH)	60.01	57.68	57.47	56.94	59.03	60.92	58.77	58.24	58.86	58.92	58.91	62.02	59.03
62														

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		2013 September	2013 October	2013 November	2013 December	2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	Test Period Total
63	**Smelters**													
64	Base Rate	47.49	47.49	47.49	47.49	47.49	47.49	47.49	47.49	47.49	47.49	47.49	47.49	47.49
65	TIER Adjustment	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.95
66	Total	50.44	50.44	50.44	50.44	50.44	50.44	50.44	50.44	50.44	50.44	50.44	50.44	50.44
67	Non-FAC PPA	(0.35)	(0.34)	(0.35)	(0.42)	(0.41)	(0.35)	(0.36)	(0.31)	(0.34)	(0.38)	(0.41)	(0.40)	(0.37)
68	FAC	4.70	4.48	4.61	4.67	4.90	5.07	5.22	5.34	5.44	5.64	5.66	5.70	5.12
69	Environmental Surcharge	3.03	2.97	2.73	2.56	2.70	2.72	2.63	2.86	2.80	2.81	2.78	3.23	2.82
70	Surcharge	1.88	1.86	1.88	1.86	1.86	1.93	1.86	1.88	1.86	1.88	1.86	1.86	1.87
71	TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
72	Effective Rate ($/ MWH)	59.70	59.41	59.30	59.11	59.48	59.81	59.78	60.21	60.20	60.39	60.32	60.82	59.88
73														
74	Market	28.45	28.08	27.89	30.71	34.60	33.68	31.84	31.93	29.94	32.48	36.22	33.82	31.23

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		2013 September	2013 October	2013 November	2013 December	2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	Test Period Total
75														
76	<u>III. Statement of Operations (Millions of $)</u>													
77														
78	Electric Energy Revenues	[redacted]												
79	Income From Leased Property Net													
80	Other Operating Revenue and Income	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	3.70
81	**TOTAL OPER. REVENUES & PAT. CAPITAL**	[redacted]												
82														
83	Operating Expense-Production-Excluding Fuel	[redacted]												
84	Operating Expense-Production-Fuel													
85	Operating Expense-Other Power Supply													
86	Operating Expense-Transmission													
87	Operating Expense-RTO/ISO													
88	Operating Expense-Distribution													
89	Operating Expense-Customer Accounts													
90	Operating Expense-Customer Service and Information													
91	Operating Expense-Sales													
92	Operating Expense-Administrative and General													
93	**TOTAL OPERATION EXPENSE**													
94														
95	Maintenance Expense-Production	[redacted]												
96	Maintenance Expense-Transmission													
97	Maintenance Expense-Distribution													
98	Maintenance Expense-General Plant													
99	**TOTAL MAINTENANCE EXPENSE**													
100														

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		2013 September	2013 October	2013 November	2013 December	2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	Test Period Total
101	Depreciation and Amortization Expense	3.64	3.64	3.65	3.66	3.66	3.66	3.66	3.67	3.69	3.70	3.70	3.71	44.04
102	Taxes	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
103	Interest on Long-Term Debt	3.82	3.97	3.87	3.97	3.91	3.66	3.98	3.90	4.01	3.88	4.01	4.01	46.98
104	Interest Charged to Construction - Credit	(0.06)	(0.10)	(0.14)	(0.18)	(0.17)	(0.19)	(0.22)	(0.29)	(0.34)	(0.38)	(0.39)	(0.01)	(2.48)
105	Other Interest Expense	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
106	Asset Retirement Obligation													
107	Other Deductions	0.04	0.05	0.05	0.07	0.05	0.05	0.05	0.05	0.04	0.06	0.04	0.04	0.59
108														
109	**TOTAL COST OF ELECTRIC SERVICE**	[redacted]												
110														
111	**OPERATING MARGINS**	(0.39)	(2.74)	0.14	3.71	4.90	3.30	(2.31)	(6.88)	(4.46)	1.67	3.48	3.36	3.77
112														
113	Interest Income	0.17	0.17	0.17	0.16	0.17	0.17	0.17	0.16	0.16	0.16	0.16	0.16	1.97
114	Allowance For Funds Used During Construction													
115	Income (Loss) From Equity Investments													
116	Other Non-Operating Income (Net)													
117	Generation and Transmission Capital Credits													
118	Other Capital Credits and Patronage Dividends	0.00	0.00	0.00	0.00	0.00	0.00	2.71	0.00	0.00	0.00	0.00	0.00	2.71
119	Extraordinary Items													
120	**NET PATRONAGE CAPITAL OR MARGIN**	(0.22)	(2.57)	0.31	3.88	5.06	3.46	0.56	(6.72)	(4.29)	1.83	3.64	3.52	8.45
121														
122														

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		2013 September	2013 October	2013 November	2013 December	2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	Test Period Total
123	**IV. Balance Sheet (Millions of $)**													
124	Total Utility Plant in Service	2,040.49	2,046.15	2,048.32	2,048.69	2,049.94	2,050.62	2,053.81	2,065.17	2,072.74	2,074.16	2,075.48	2,139.74	2,139.74
125	Construction Work in Progress	50.29	57.51	64.76	72.20	77.36	82.55	87.83	93.13	98.46	101.21	101.50	40.00	40.00
126	Total Utility Plant	2,090.79	2,103.66	2,113.09	2,120.89	2,127.30	2,133.18	2,141.64	2,158.31	2,171.20	2,175.37	2,176.98	2,179.74	2,179.74
127	Accum. Provision for Depreciation and Amort.	992.09	994.23	997.49	1,001.32	1,004.86	1,008.59	1,011.52	1,011.90	1,013.51	1,017.09	1,020.70	1,023.83	1,023.83
128	NET UTILITY PLANT	1,098.70	1,109.43	1,115.60	1,119.57	1,122.44	1,124.59	1,130.12	1,146.41	1,157.69	1,158.28	1,156.28	1,155.91	1,155.91
129														
130	Non-Utility Property (Net)													
131	Invest. In Assoc. Org - Patronage Capital	4.15	4.15	4.15	4.15	4.15	4.15	4.32	4.32	4.32	4.32	4.32	4.32	4.32
132	Invest. In Assoc. - Other - General Funds	42.88	42.88	42.55	42.55	42.55	42.22	42.22	42.22	41.89	41.89	41.89	41.54	41.54
133	Other Investments	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
134	Special Funds	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05
135	Special Funds (Transition Reserve)	35.10	35.11	35.12	35.13	35.13	35.14	35.15	35.16	35.17	35.18	35.19	35.20	35.20
136	Special Funds (Economic Reserve)	61.89	59.74	57.36	54.28	50.94	48.02	45.33	43.06	40.54	37.34	34.42	31.36	31.36
137	Special Funds (Rural Economic Reserve)	65.29	65.39	65.49	65.60	65.70	65.79	65.89	65.99	66.10	66.20	66.30	66.40	66.40
138	TOTAL OTHER PROP. AND INVESTMENTS	210.38	208.34	205.74	202.77	199.54	196.39	193.98	191.81	189.07	185.97	183.18	179.88	179.88
139														
140	Cash - General Funds	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
141	Cash - Construction Funds - Trustee													
142	Special Deposits	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60
143	Temporary Investments	116.23	107.92	97.02	84.63	96.50	98.34	107.96	93.87	73.78	70.15	74.43	74.09	74.09
144	Accounts Receivable - Sales of Energy (Net)	38.09	38.45	38.33	42.17	44.71	40.14	38.51	34.77	36.54	40.56	42.67	43.39	43.39
145	Accounts Receivable - Other (Net)	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22
146	Fuel Stock	32.76	32.97	33.10	33.18	33.56	33.78	34.02	34.08	34.03	34.09	34.14	34.16	34.16
147	Materials and Supplies - Other	26.70	26.76	26.83	26.89	26.96	27.02	27.09	27.15	27.22	27.28	27.35	27.41	27.41
148	Prepayments	1.17	0.87	0.58	4.18	3.86	3.53	3.21	2.88	2.56	2.23	1.91	1.58	1.58
149	Other Current and Accrued Assets	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71
150	TOTAL CURRENT AND ACCRUED ASSETS	217.48	209.51	198.39	193.59	208.12	205.35	213.32	195.29	176.66	176.85	183.02	183.16	183.16
151														
152	Unamortized Debt Discount & Extraor. Prop. Losses	4.93	4.90	4.86	4.83	4.80	4.77	4.73	4.70	4.67	4.63	4.60	4.57	4.57
153	Regulatory Assets	6.58	6.44	6.29	6.15	6.01	5.87	5.73	5.58	5.44	5.30	5.16	5.02	5.02
154	Other Deferred Debits	2.56	2.51	2.47	2.42	2.37	2.36	2.29	2.24	2.23	2.17	2.25	2.23	2.23
155	Accumulated Deferred Income Taxes	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
156														
157	TOTAL ASSETS AND OTHER DEBITS	1,540.62	1,541.12	1,533.37	1,529.33	1,543.28	1,539.32	1,550.17	1,546.04	1,535.76	1,533.22	1,534.49	1,530.77	1,530.77
158														

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		2013 September	2013 October	2013 November	2013 December	2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	Test Period Total
159														
160	**TOTAL MARGINS & EQUITY**	402.35	399.78	400.08	403.96	409.02	412.49	413.05	406.33	402.04	403.87	407.51	411.02	411.02
161														
162	Long-Term Debt - RUS	216.13	216.14	216.14	218.13	218.14	218.14	220.11	220.12	220.12	222.15	222.16	222.16	222.16
163	Long-Term Debt - Other	730.02	730.02	726.99	725.10	734.10	731.05	738.14	738.14	735.06	737.25	737.25	734.15	734.15
164	**TOTAL LONG-TERM DEBT**	946.14	946.16	943.13	943.23	952.24	949.19	958.26	958.27	955.19	959.40	959.41	956.31	956.31
165														
166	Notes Payable	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
167	Accounts Payable	22.93	24.95	22.37	20.18	23.37	21.56	25.68	27.36	26.29	23.22	23.01	23.53	23.53
168	Accounts Payable (TIER Rebate)	0.00	0.00	0.00	0.00	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
169	Taxes Accrued	1.01	1.34	1.10	0.81	0.58	0.93	1.28	1.63	1.98	2.33	2.68	0.75	0.75
170	Interest Accrued	4.50	7.29	7.40	4.89	5.11	5.08	4.46	7.21	7.48	4.79	5.13	5.42	5.42
171	Other Current and Accrued Liabilities	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29
172														
173	**TOTAL CURRENT AND ACCRUED LIAB.**	36.73	41.87	39.16	34.17	37.35	35.86	39.71	44.50	44.05	38.63	39.12	37.99	37.99
174														
175	Deferred Credits	2.25	2.15	2.04	1.92	1.80	1.68	1.56	1.45	1.34	1.22	1.10	0.98	0.98
176	Deferred Credits (Economic Reserve)	61.89	59.74	57.36	54.28	50.94	48.02	45.33	43.06	40.54	37.34	34.42	31.36	31.36
177	Deferred Credits (Rural Economic Reserve)	65.29	65.39	65.49	65.60	65.70	65.79	65.89	65.99	66.10	66.20	66.30	66.40	66.40
178	Accumulated Operating Provisions	25.98	26.04	26.11	26.17	26.24	26.30	26.37	26.44	26.50	26.57	26.63	26.70	26.70
179	Obligation under Capital Leases - Noncurrent													
180														
181	**TOTAL LIABILITIES AND OTHER CREDITS**	1,540.62	1,541.12	1,533.37	1,529.33	1,543.28	1,539.32	1,550.17	1,546.04	1,535.76	1,533.22	1,534.49	1,530.77	1,530.77
182														

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		2013 September	2013 October	2013 November	2013 December	2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	Test Period Total
183														
184	**V. Cash Flow Statement (Millions of $)**													
185	Operating Receipts													
186	Rural	11.67	9.67	11.02	14.72	15.83	13.75	12.13	9.52	10.77	13.80	15.36	15.79	154.01
187	Large Industrial	3.68	3.76	3.71	3.76	3.79	3.66	3.81	3.73	3.76	3.71	4.09	4.07	45.52
188	Smelters	15.50	15.94	15.40	15.86	15.96	14.49	16.04	15.64	16.15	15.68	16.19	16.32	189.17
189	Offsystem	[redacted]												
190	Lease Income													
191	Other Operating Revenues	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	3.70
192	Gain on Sale of Allowances	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
193	Other	0.00	0.00	0.00	0.00	0.00	0.00	2.71	0.00	0.00	0.00	0.00	0.00	2.71
194	Interest Earnings	0.17	0.17	0.17	0.16	0.17	0.17	0.17	0.16	0.16	0.16	0.16	0.16	1.97
195	Total Receipts	[redacted]												
196														
197	Operating Disbursements													
198	PPA													
199	Fuel Costs	[redacted]												
200	Fuel Costs (Labor & Exp)													
201	Domtar	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
202	Power Supply (P Power, APM, Cogen, & TVA Tran)	[redacted]												
203	Production O&M													
204	Transmission O&M													
205	A&G													
206	Working Capital	(7.10)	(2.28)	2.07	9.91	(0.73)	(3.77)	(6.26)	(6.11)	1.83	6.42	1.64	1.46	(2.91)
207	Other	(0.14)	(0.14)	(0.14)	(0.14)	(0.13)	(0.14)	(0.14)	(0.14)	(0.14)	(0.12)	(0.14)	(0.14)	(1.62)
208	Total Disbursements	[redacted]												
209														
210	Operating Receipts less Disbursements	11.82	5.23	3.45	(1.38)	9.82	11.55	11.70	4.71	(0.90)	(0.29)	6.73	7.02	69.46

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		2013 September	2013 October	2013 November	2013 December	2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	Test Period Total
211														
212	Capital Expenditures													
213	Generation	[redacted]												
214	Transmission	0.41	0.85	1.58	0.15	0.22	0.33	0.33	0.39	0.38	0.33	0.17	0.36	5.51
215	A&G	0.15	0.20	0.20	0.20	0.00	0.21	0.10	0.25	0.00	0.00	0.00	0.00	1.30
216	Other / IT	0.15	0.11	0.12	0.08	0.00	0.05	0.10	0.31	0.11	0.26	0.22	0.32	1.82
217	Total Capital Expenditures	[redacted]												
218														
219	Income Taxes from Operations	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
220														
221	Net Pre-Finance Cash Flow	5.35	(9.32)	(6.51)	(9.11)	3.19	5.65	2.45	(15.25)	(15.81)	(4.49)	5.13	3.40	(35.32)
222														
223	Financing													
224	Principal	(14.94)	0.00	3.03	1.88	(9.00)	3.05	(7.09)	0.00	3.08	(2.19)	0.00	3.10	(19.07)
225	Interest	2.62	1.17	3.76	4.49	3.68	3.70	2.63	1.13	3.74	4.55	3.65	3.71	38.82
226	Debt Issuance Cost	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02
227	Line of Credit (Upfront Fee)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.13	0.00	0.13
228	Aggregate Debt Service (incl. Line of Credit)	(12.32)	1.17	6.79	6.39	(5.32)	6.75	(4.46)	1.13	6.82	2.36	3.78	6.82	19.90
229														
230	Post-Finance Cash Flow	17.67	(10.49)	(13.30)	(15.51)	8.51	(1.10)	6.91	(16.37)	(22.63)	(6.85)	1.35	(3.41)	(55.22)
231														
232	Unwind Transaction													
233	Cash Proceeds													
234	Debt Reduction													
235	Misc. Transaction													
236	Net Before Member Reserves													
237	Station Two O&M Fund													
238	Rural Economic Reserve	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
239	Economic Reserve	2.57	2.18	2.41	3.12	3.38	2.95	2.72	2.30	2.54	3.23	2.93	3.08	33.41
240	Net Before Transition Reserve	2.57	2.18	2.41	3.12	3.38	2.95	2.72	2.30	2.54	3.23	2.93	3.08	33.41
241														

Big Rivers Electric Corporation
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Big Rivers Financial Model

		2013 September	2013 October	2013 November	2013 December	2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	Test Period Total
242	Ending Cash Balances (Incl. Transition Reserve)	151.33	143.03	132.14	119.76	131.64	133.49	143.11	129.04	108.95	105.33	109.62	109.29	109.29
243	Ending Cash Balances excl. Transition Reserve)	116.23	107.92	97.03	84.63	96.51	98.35	107.96	93.88	73.78	70.15	74.43	74.09	74.09
244	Change in Working Capital													
245	Other Property	0.00	0.00	(0.33)	0.00	0.00	(0.33)	0.16	0.00	(0.34)	0.00	0.00	(0.34)	(1.18)
246	Accounts Receivable	(11.96)	0.36	(0.12)	3.84	2.55	(4.57)	(1.63)	(3.75)	1.77	4.02	2.11	0.72	(6.66)
247	Materials, Supplies & Other	0.06	0.06	0.06	0.06	0.06	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.77
248	Prepayments	(0.30)	(0.30)	(0.30)	3.61	(0.33)	(0.33)	(0.33)	(0.33)	(0.33)	(0.33)	(0.33)	(0.33)	0.12
249	Other Current Assets	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
250	Accounts Payable	5.48	(2.02)	2.58	2.19	(3.18)	1.81	(4.12)	(1.68)	1.07	3.07	0.21	(0.51)	4.88
251	Taxes Accrued	(0.32)	(0.32)	0.24	0.29	0.23	(0.35)	(0.35)	(0.35)	(0.35)	(0.35)	(0.35)	1.93	(0.06)
252	Other Accruals	(0.06)	(0.06)	(0.07)	(0.07)	(0.07)	(0.07)	(0.07)	(0.07)	(0.07)	(0.07)	(0.07)	(0.07)	(0.79)
253	Total	(7.10)	(2.28)	2.07	9.91	(0.73)	(3.77)	(6.26)	(6.11)	1.83	6.42	1.64	1.46	(2.91)
254														

Big Rivers Electric Corporation
Case No. 2012-00535
Big Rivers Financial Model

		2013 September	2013 October	2013 November	2013 December	2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	Test Period Total
255														
256	**VI. Cash Flow Statement - Indirect (Millions of $)**													
257														
258	**Cash Flows From Operating Activities:**													
259	Net Margin	(0.22)	(2.57)	0.31	3.88	5.06	3.46	0.56	(6.72)	(4.29)	1.83	3.64	3.52	8.45
260	Adjustments to reconcile net margin to net cash													
261	provided by operating activities:													
262	Depreciation and amortization	3.91	3.92	3.93	3.93	3.94	3.94	3.94	3.95	3.97	3.99	4.00	4.00	47.43
263	Interest compounded - RUS Series A Note	0.00	0.01	0.00	0.00	0.01	0.00	0.00	0.01	0.00	0.00	0.01	0.00	0.05
264	Interest compounded - RUS Series B Note	1.96	0.00	0.00	1.99	0.00	0.00	1.97	0.00	0.00	2.02	0.00	0.00	7.95
265	Noncash member rate mitigation revenue	(2.54)	(2.15)	(2.38)	(3.09)	(3.36)	(2.93)	(2.69)	(2.27)	(2.51)	(3.21)	(2.91)	(3.06)	(33.09)
266	Changes in certain assets and liabilities:													
267	Other property	0.00	0.00	0.33	0.00	0.00	0.33	(0.16)	0.00	0.34	0.00	0.00	0.34	1.18
268	Accounts receivable	11.96	(0.36)	0.12	(3.84)	(2.55)	4.57	1.63	3.75	(1.77)	(4.02)	(2.11)	(0.72)	6.66
269	Inventories	(0.35)	(0.27)	(0.20)	(0.14)	(0.44)	(0.29)	(0.30)	(0.12)	(0.02)	(0.13)	(0.11)	(0.09)	(2.46)
270	Prepayments	0.30	0.30	0.30	(3.61)	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	(0.12)
271	Other current assets	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
272	Accounts payable	(5.48)	2.02	(2.58)	(2.19)	3.18	(1.81)	4.12	1.68	(1.07)	(3.07)	(0.21)	0.51	(4.88)
273	Taxes accrued	0.32	0.32	(0.24)	(0.29)	(0.23)	0.35	0.35	0.35	0.35	0.35	0.35	(1.93)	0.06
274	Other accruals	(0.66)	2.84	0.11	(2.52)	0.20	(0.11)	(0.68)	2.62	0.04	(2.93)	0.10	0.40	(0.59)
275	Net cash provided by operating activities	9.20	4.06	(0.31)	(5.87)	6.14	7.85	9.07	3.58	(4.64)	(4.84)	3.08	3.31	30.64
276														
277	**Cash Flows From Investing Activities:**													
278	Capital expenditures	(6.47)	(14.55)	(9.96)	(7.73)	(6.64)	(5.90)	(9.25)	(19.95)	(14.91)	(4.20)	(1.60)	(3.62)	(104.78)
279	Net proceeds from restricted investments	2.56	2.18	2.40	3.11	3.37	2.94	2.71	2.29	2.53	3.22	2.93	3.08	33.31
280	Net cash provided by (used in) inv. Activities	(3.91)	(12.37)	(7.56)	(4.62)	(3.27)	(2.96)	(6.54)	(17.66)	(12.38)	(0.98)	1.32	(0.54)	(71.47)

Big Rivers Electric Corporation
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Big Rivers Financial Model

		2013 September	2013 October	2013 November	2013 December	2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	Test Period Total
281														
282	**Cash Flows From Financing Activities:**													
283	Net principal payments on debt obligations	14.94	0.00	(3.03)	(1.88)	9.00	(3.05)	7.09	0.00	(3.08)	2.19	0.00	(3.10)	19.07
284	Debt issuance cost	0.00	0.00	0.00	(0.02)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.02)
285	Line of Credit (Upfront Fee)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.13)	0.00	(0.13)
286	Net cash provided by (used in) Financihng Activities	14.94	0.00	(3.03)	(1.90)	9.00	(3.05)	7.09	0.00	(3.08)	2.19	(0.13)	(3.10)	18.92
287														
288	Net increase (decrease) in cash	20.23	(8.31)	(10.89)	(12.40)	11.88	1.84	9.62	(14.08)	(20.10)	(3.63)	4.28	(0.34)	(21.91)
289														
290	**Cash and Cash Equivalents - Beg. of Period**													96.00
291	**Cash and Cash Equivalents - End of Period**													74.09

Big Rivers Electric Corporation
Case No. 2012-00535
Statement of Operations (With and Without Proposed Rate Increase)
Fully Forecasted Test Period (September 2013 to August 2014)

		With Proposed Rate Increase	Without Proposed Rate Increase
1	Electric Energy Revenues	[redacted]	
2	Income From Leased Property Net	0	0
3	Other Operating Revenue and Income	3,696,500	3,696,500
4	**TOTAL OPER. REVENUES & PATRONAGE CAPITAL**	[redacted]	
5			
6	Operating Expense-Production-Excluding Fuel	[redacted]	
7	Operating Expense-Production-Fuel		
8	Operating Expense-Other Power Supply		
9	Operating Expense-Transmission		
10	Operating Expense-RTO/ISO		
11	Operating Expense-Distribution		
12	Operating Expense-Customer Accounts		
13	Operating Expense-Customer Service and Information		
14	Operating Expense-Sales		
15	Operating Expense-Administrative and General		
16	**TOTAL OPERATION EXPENSE**		
17			
18	Maintenance Expense-Production	[redacted]	
19	Maintenance Expense-Transmission		
20	Maintenance Expense-Distribution		
21	Maintenance Expense-General Plant		
22	**TOTAL MAINTENANCE EXPENSE**		
23			
24	Depreciation and Amortization Expense	44,042,489	44,042,489
25	Taxes	885	885
26	Interest on Long-Term Debt	46,983,291	46,983,291
27	Interest Charged to Construction - Credit	(2,480,401)	(2,480,401)
28	Other Interest Expense	0	0
29	Asset Retirement Obligation	0	0
30	Other Deductions	591,094	591,094
31			
32	**TOTAL COST OF ELECTRIC SERVICE**	[redacted]	
33			
34	**OPERATING MARGINS**	[redacted]	
35			
36	Interest Income	1,974,858	1,974,858
37	Allowance For Funds Used During Construction	0	0
38	Income (Loss) From Equity Investments	0	0
39	Other Non-Operating Income (Net)	0	0
40	Generation and Transmission Capital Credits	0	0
41	Other Capital Credits and Patronage Dividends	2,706,448	2,706,448
42	Extraordinary Items	0	0
43	**NET PATRONAGE CAPITAL OR MARGIN**	[redacted]	

Big Rivers Electric Corporation
Calculation of Revenue Requirement
Based on Fully Forecasted Test Period
For the 12 Months Ended August 31, 2014

Line	Description	Ref Sched		Amount
1	**Total Oper Revenue & Patronage Capital Without Proposed Rate Increase**	Exh Siewert-3.2	$	409,058,933
2				
3	**Adjustments to Revenue**			
4	To Remove Fuel Adjustment Clause Revenue	1.01	$	(33,539,328)
5	To Remove Environmental Surcharge Revenue	1.02	$	(20,731,985)
6	To Remove Non-FAC PPA Revenue	1.03	$	3,806,042
7	Subtotal	Lines 4-6	$	(50,465,271)
8				
9	Adjusted Revenue	Line 1 + Line 7	$	358,593,662
10				
11	**Total Cost of Service**	Exh Siewert-3.2	$	478,313,780
12				
13	**Adjustments to Cost of Service**			
14	To Remove Fuel Expense Recoverable through the FAC	1.01	$	(33,539,328)
15	To Remove Expenses Recoverable through the ES	1.02	$	(20,731,985)
16	To Remove Expenses Recoverable through the Non-FAC PPA	1.03	$	3,806,042
17	To Remove Promotional Advertising	1.04	$	(55,756)
18	To Remove Lobbying Expenses	1.05	$	(70,923)
19	To Remove Economic Development Expenses	1.06	$	(140,357)
20	To Remove Donations Expenses	1.07	$	(63,328)
21	To Remove Touchstone Energy dues	1.08	$	(132,766)
22	To Amortize 2011 Rate Case Expenses for Case No. 2011-00036	1.09	$	203,352
23	To Remove Non-recurring Labor related to Wilson Layup	1.10	$	(2,595,458)
24	To Normalize Certain Outside Professional Services	1.11	$	(267)
25	To Normalize Demand Side Management Expenses	1.12	$	(131,314)
26	Subtotal	Lines 14 - 25	$	(53,452,087)
27				
28	Adjusted Cost of Service	Line 11 + Line 26	$	424,861,693

Big Rivers Electric Corporation
Calculation of Revenue Requirement
Based on Fully Forecasted Test Period
For the 12 Months Ended August 31, 2014

Line	Description	Ref Sched	Amount
29			
30	Adjusted Operating Margins	Line 9 - Line 28	$ (66,268,031)
31			
32	**Non-Operating Items**		
33	Interest Income	Exh Siewert-3.2	$ 1,974,858
34	Other Non-Operating Income	Exh Siewert-3.2	$ -
35	Other Capital Credits / Patronage Dividends	Exh Siewert-3.2	$ 2,706,448
36			
37	Total Non-Operating Items	Lines 33-35	$ 4,681,305
38			
39	**Calculation of Revenue Deficiency**		
40			
41	Adjusted Net Margin (Deficit)	Line 30 + 37	$ (61,586,726)
42			
43	Contract TIER		1.24
44			
45	Interest on Long-Term Debt	Exh Siewert-3.2	$ 46,983,291
46			
47	Interest Income on Transition Reserve	Big Rivers Finan Model	$ 105,415
48			
49	Adjusted Net Margin(Deficit) before Contract TIER	Line 41 - 47	$ (61,692,141)
50			
51	Margins Required for Contract TIER	Line 45*(Line 43-1) + Line 47	$ 11,381,405
52			
53	**Revenue Deficiency for 1.24 Contract TIER**	Line 41 - 51	**$ (72,968,131)**

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
August 31, 2014

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Transmission Demand
Plant in Service						
Intangible Plant	INTPLT	PT&D	$ 66,895	58,452	-	8,443
Production Plant	PPROD	F001	$ 1,769,875,009	1,769,875,009	-	-
Transmission Plant	PTRAN	F002	$ 255,644,032	-	-	255,644,032
Distribution Plant	PDIST	F003	$ -	-	-	-
Total Production & Transmission Plant	PT&D		2,025,519,041	1,769,875,009	-	255,644,032
General Plant	PGP	PT&D	$ 36,225,459	31,653,385	-	4,572,074
Total Plant in Service	TPIS		$ 2,061,811,395	$ 1,801,586,846	$ -	$ 260,224,549
Construction Work in Progress (CWIP)						
CWIP Production	CWIP1	PPROD	$ 59,715,449	59,715,449	-	-
CWIP Transmission	CWIP2	PTRAN	$ 14,556,975	-	-	14,556,975
CWIP Distribution Plant	CWIP3	PDIST	$ -	-	-	-
CWIP General Plant	CWIP4	PT&D	$ 617,305	539,394	-	77,911
Total Construction Work in Progress	TCWIP		$ 74,889,729	$ 60,254,843	$ -	$ 14,634,886
Total Utility Plant			$ 2,136,701,124	$ 1,861,841,689	$ -	$ 274,859,435

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
August 31, 2014

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Transmission Demand
Rate Base						
Total Utility Plant	TUP		$ 2,136,701,124	$ 1,861,841,689	$ -	$ 274,859,435
Less: Acummulated Provision for Depreciation						
Production	ADEPREPA	PPROD	$ 874,821,528	874,821,528	-	-
Transmission	ADEPRTP	PTRAN	$ 122,535,081	-	-	122,535,081
Distribution	ADEPRD11	PDIST	$ -	-	-	-
General & Common Plant	ADEPRD12	PT&D	$ 9,260,405	8,091,634	-	1,168,771
Intangible, Misc, and Other Plant	ADEPRGP	PT&D	$ -	-	-	-
Retirement Work In Progress	ADEPRRT	PT&D	$ -	-	-	-
Total Accumulated Depreciation	TADEPR		$ 1,006,617,014	$ 882,913,162	$ -	$ 123,703,852
Net Utility Plant	NTPLANT		$ 1,130,084,110	$ 978,928,527	$ -	$ 151,155,583
Working Capital						
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP	$ 47,318,685	11,333,633	33,574,606	2,410,446
Materials and Supplies	M&S	TPIS	$ 27,026,950	23,615,835	-	3,411,115
Fuel Stock	PREPAY	TPIS	$ 33,315,891	29,111,039	-	4,204,852
Total Working Capital	TWC		$ 107,661,526	$ 64,060,507	$ 33,574,606	$ 10,026,413
Net Rate Base	RB		$ 1,237,745,636	$ 1,042,989,034	$ 33,574,606	$ 161,181,996

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
August 31, 2014

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Transmission Demand
Operation and Maintenance Expenses						
Steam Power Generation Operation Expenses						
500 OPERATION SUPERVISION & ENGINEERING	OM500	PROFIX	[redacted]			-
501 FUEL	OM501	Energy				-
502 STEAM EXPENSES	OM502	PROFIX				-
505 ELECTRIC EXPENSES	OM505	PROFIX				-
506 MISC. STEAM POWER EXPENSES	OM506	PROFIX				-
507 RENTS	OM507	PROFIX				-
509 ALLOWANCES	OM509	Energy				-
Total Steam Power Operation Expenses						$ -
Steam Power Generation Maintenance Expenses						
510 MAINTENANCE SUPERVISION & ENGINEERING	OM510	Energy				-
511 MAINTENANCE OF STRUCTURES	OM511	PROFIX				-
512 MAINTENANCE OF BOILER PLANT	OM512	Energy				-
513 MAINTENANCE OF ELECTRIC PLANT	OM513	Energy				-
514 MAINTENANCE OF MISC STEAM PLANT	OM514	PROFIX				-
Total Steam Power Generation Maintenance Expense						$ -
Total Steam Power Generation Expense						$ -

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
August 31, 2014

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Transmission Demand
Operation and Maintenance Expenses (Continued)						
Other Power Generation Operation Expense						
546 OPERATION SUPERVISION & ENGINEERING	OM546	PROFIX	[redacted]	[redacted]	[redacted]	-
547 FUEL	OM547	Energy	[redacted]	[redacted]	[redacted]	-
548 GENERATION EXPENSE	OM548	PROFIX	[redacted]	[redacted]	[redacted]	-
549 MISC OTHER POWER GENERATION	OM549	PROFIX	[redacted]	[redacted]	[redacted]	-
550 RENTS	OM550	PROFIX	[redacted]	[redacted]	[redacted]	-
Total Other Power Generation Expenses			[redacted]	[redacted]	[redacted]	$ -
Other Power Generation Maintenance Expense						
551 MAINTENANCE SUPERVISION & ENGINEERING	OM551	PROFIX	[redacted]	[redacted]	[redacted]	-
552 MAINTENANCE OF STRUCTURES	OM552	PROFIX	[redacted]	[redacted]	[redacted]	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	OM553	PROFIX	[redacted]	[redacted]	[redacted]	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	OM554	PROFIX	[redacted]	[redacted]	[redacted]	-
Total Other Power Generation Maintenance Expense			[redacted]	[redacted]	[redacted]	$ -
Total Other Power Generation Expense			[redacted]	[redacted]	[redacted]	$ -
Total Station Expense			[redacted]	[redacted]	[redacted]	$ -

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
August 31, 2014

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Transmission Demand
Operation and Maintenance Expenses (Continued)						
Other Power Supply Expenses						
555 PURCHASED POWER Energy	OM555	OMPP	[redacted]			-
555 PURCHASED POWER Demand	OMD555	OMPPD	[redacted]			-
555 PURCHASED POWER BREC Share of HMP&L Station Two	OMH555	OMPPH	[redacted]			-
555 PURCHASED POWER OPTIONS	OMO555	OMPP	[redacted]			-
555 BROKERAGE FEES	OMB555	OMPP	[redacted]			-
555 MISO TRANSMISSION EXPENSES	OMM555	OMPP	[redacted]			-
556 SYSTEM CONTROL AND LOAD DISPATCH	OM556	PROFIX	[redacted]			-
557 OTHER EXPENSES	OM557	PROFIX	[redacted]			-
558 DUPLICATE CHARGES	OM558	Energy	[redacted]			-
Total Other Power Supply Expenses	TPP		[redacted]			$ -
Total Electric Power Generation Expenses			[redacted]			$ -
Transmission Expenses						
560 OPERATION SUPERVISION AND ENG	OM560	LBTRAN	$ 956,020	-	-	956,020
561 LOAD DISPATCHING	OM561	LBTRAN	$ 2,438,223	-	-	2,438,223
562 STATION EXPENSES	OM562	PTRAN	$ 720,812	-	-	720,812
563 OVERHEAD LINE EXPENSES	OM563	PTRAN	$ 1,236,070	-	-	1,236,070
565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	PTRAN	$ 2,448,000	-	-	2,448,000
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	$ 613,921	-	-	613,921
567 RENTS	OM567	PTRAN	$ 58,669	-	-	58,669
568 MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN	$ 540,092	-	-	540,092
569 STRUCTURES	OM569	PTRAN	$ (83,165)	-	-	(83,165)
570 MAINT OF STATION EQUIPMENT	OM570	PTRAN	$ 1,720,315	-	-	1,720,315
571 MAINT OF OVERHEAD LINES	OM571	PTRAN	$ 2,310,747	-	-	2,310,747
572 UNDERGROUND LINES	OM572	PTRAN	$ -	-	-	-
573 MISC PLANT	OM573	PTRAN	$ 756,058	-	-	756,058
573 MARKET FACILITATION MONITORING MISO	OM575	PTRAN	$ 1,343,829	-	-	1,343,829
Total Transmission Expenses			$ 15,059,590	$ -	$ -	$ 15,059,590

Case No. 2012-00535
Attachment for Response to PSC 2-36 - Exhibit Wolfram-3.2
Witness: John Wolfram

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
August 31, 2014

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Transmission Demand
Operation and Maintenance Expenses (Continued)						
Total Distribution Maintenance Expense	OMDM		$ -	$ -	$ -	$ -
Total Distribution Operation and Maintenance Expenses			-	-	-	-
Transmission and Distribution Expenses			15,059,590	-	-	15,059,590
Production, Transmission and Distribution Expenses	OMSUB		[redacted]			$ 15,059,590
Customer Accounts Expense						
901 SUPERVISION/CUSTOMER ACCTS	OM901	F025	$ -	-	-	-
902 METER READING EXPENSES	OM902	F025	$ -	-	-	-
903 RECORDS AND COLLECTION	OM903	F025	$ -	-	-	-
904 UNCOLLECTIBLE ACCOUNTS	OM904	F025	$ -	-	-	-
905 MISC CUST ACCOUNTS	OM903	F025	$ -	-	-	-
Total Customer Accounts Expense	OMCA		$ -	$ -	$ -	$ -
Customer Service Expense						
907 SUPERVISION	OM907	TUP	$ -	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	OM908	TUP	$ 1,341,868	1,169,254	-	172,614
908 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	TUP	$ -	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	OM909	TUP	$ 32,467	28,290	-	4,176
909 INFORM AND INSTRUC -LOAD MGMT	OM909x	TUP	$ -	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	OM910	TUP	$ -	-	-	-
911 DEMONSTRATION AND SELLING EXP	OM911	TUP	$ -	-	-	-
912 DEMONSTRATION AND SELLING EXP	OM912	TUP	$ -	-	-	-
913 ADVERTISING EXPENSES	OM913	TUP	$ 139,067	121,178	-	17,889
915 MDSE-JOBBING-CONTRACT	OM915	TUP	$ -	-	-	-
916 MISC SALES EXPENSE	OM916	TUP	$ -	-	-	-
Total Customer Service Expense	OMCS		$ 1,513,401	$ 1,318,722	$ -	$ 194,680
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2		360,561,179	76,946,956	268,359,952	15,254,270

Case No. 2012-00535
Attachment for Response to PSC 2-36 - Exhibit Wolfram-3.2
Witness: John Wolfram

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
August 31, 2014

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Transmission Demand
Operation and Maintenance Expenses (Continued)						
Administrative and General Expense						
920 ADMIN. & GEN. SALARIES-	OM920	LBSUB9	$ 13,800,793	6,604,776	5,242,723	1,953,294
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB9	$ 8,647,072	4,138,311	3,284,898	1,223,863
922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB9	$ -	-	-	-
923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB9	$ 3,651,543	1,747,553	1,387,168	516,821
924 PROPERTY INSURANCE	OM924	TUP	$ -	-	-	-
925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB9	$ -	-	-	-
926 EMPLOYEE BENEFITS	OM926	LBSUB9	$ 401,841	192,313	152,654	56,875
927 FRANCHISE REQUIREMENTS	OM927	TUP	$ -	-	-	-
928 REGULATORY COMMISSION FEES	OM928	TUP	$ -	-	-	-
929 DUPLICATE CHARGES-CR	OM929	LBSUB9	$ -	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB9	$ 1,772,549	848,306	673,366	250,878
931 RENTS AND LEASES	OM931	PGP	$ 1,933	1,689	-	244
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP	$ 216,483	189,160	-	27,323
Total Administrative and General Expense	OMAG		$ 28,492,214	$ 13,722,109	$ 10,740,809	$ 4,029,297
Total Operation and Maintenance Expenses	TOM		[redacted]			$ 19,283,567
Operation and Maintenance Expenses Less Purchased Power	OMLPP		[redacted]			19,283,567

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
August 31, 2014

Description	Name	Functional Vector		Total System		Production Demand		Production Energy		Transmission Demand
Labor Expenses										
Steam Power Generation Operation Expenses										
500 OPERATION SUPERVISION & ENGINEERING	LB500	PROFIX	$	4,280,950		4,280,950		-		-
501 FUEL	LB501	Energy	$	2,902,882		-		2,902,882		-
502 STEAM EXPENSES	LB502	PROFIX	$	5,491,704		5,491,704		-		-
505 ELECTRIC EXPENSES	LB505	PROFIX	$	5,535,107		5,535,107		-		-
506 MISC. STEAM POWER EXPENSES	LB506	PROFIX	$	1,356,089		1,356,089		-		-
507 RENTS	LB507	PROFIX	$	-		-		-		-
509 ALLOWANCES	LB509	Energy	$	-		-		-		-
Total Steam Power Operation Expenses	LBSUB1		$	19,566,731	$	16,663,849	$	2,902,882	$	-
Steam Power Generation Maintenance Expenses										
510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	Energy	$	4,294,352		-		4,294,352		-
511 MAINTENANCE OF STRUCTURES	LB511	PROFIX	$	834,792		834,792		-		-
512 MAINTENANCE OF BOILER PLANT	LB512	Energy	$	6,591,131		-		6,591,131		-
513 MAINTENANCE OF ELECTRIC PLANT	LB513	Energy	$	1,263,465		-		1,263,465		-
514 MAINTENANCE OF MISC STEAM PLANT	LB514	PROFIX	$	1,294,907		1,294,907		-		-
Total Steam Power Generation Maintenance Expense	LBSUB2		$	14,278,646	$	2,129,699	$	12,148,947	$	-
Total Steam Power Generation Expense			$	33,845,377	$	18,793,548	$	15,051,830	$	-

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
August 31, 2014

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Transmission Demand
Labor Expenses (Continued)						
Other Power Generation Operation Expense						
546 OPERATION SUPERVISION & ENGINEERING	LB546	PROFIX	$ -	-	-	-
547 FUEL	LB547	Energy	$ -	-	-	-
548 GENERATION EXPENSE	LB548	PROFIX	$ -	-	-	-
549 MISC OTHER POWER GENERATION	LB549	PROFIX	$ -	-	-	-
550 RENTS	LB550	PROFIX	$ -	-	-	-
Total Other Power Generation Expenses	LBSUB7		$ -	$ -	$ -	$ -
Other Power Generation Maintenance Expense						
551 MAINTENANCE SUPERVISION & ENGINEERING	LB551	PROFIX	$ -	-	-	-
552 MAINTENANCE OF STRUCTURES	LB552	PROFIX	$ -	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	LB553	PROFIX	$ -	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX	$ -	-	-	-
Total Other Power Generation Maintenance Expense	LBSUB8		$ -	$ -	$ -	$ -
Total Other Power Generation Expense			$ -	$ -	$ -	$ -
Total Production Expense	LPREX		$ 33,845,377	$ 18,793,548	$ 15,051,830	$ -

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
August 31, 2014

Description	Name	Functional Vector		Total System		Production Demand		Production Energy		Transmission Demand
Labor Expenses (Continued)										
Purchased Power										
555 PURCHASED POWER Energy	LB555	OMPP	$	-		-		-		-
555 PURCHASED POWER Demand	LBD555	OMPPD	$	-		-		-		-
555 PURCHASED POWER OPTIONS	LBO555	OMPP	$	-		-		-		-
555 BROKERAGE FEES	LBB555	OMPP	$	-		-		-		-
555 MISO TRANSMISSION EXPENSES	LBM555	OMPP	$	-		-		-		-
556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX	$	-		-		-		-
557 OTHER EXPENSES	LB557	PROFIX	$	-		-		-		-
558 DUPLICATE CHARGES	LB558	Energy	$	-		-		-		-
Total Purchased Power Labor	LBPP		$	-	$	-	$	-	$	-
Transmission Labor Expenses										
560 OPERATION SUPERVISION AND ENG	LB560	PTRAN	$	777,780		-		-		777,780
561 LOAD DISPATCHING	LB561	PTRAN	$	1,115,069		-		-		1,115,069
562 STATION EXPENSES	LB562	PTRAN	$	200,779		-		-		200,779
563 OVERHEAD LINE EXPENSES	LB563	PTRAN	$	72,556		-		-		72,556
565 TRANSMISSION OF ELECTRICITY BY OTHERS	LB565	PTRAN	$	-		-		-		-
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN	$	410,985		-		-		410,985
567 RENTS	LB567	PTRAN	$	-		-		-		-
568 MAINTENACE SUPERVISION AND ENG	LB568	PTRAN	$	260,558		-		-		260,558
569 MAINTENACE OF STRUCTURES	LB569	PTRAN	$	-		-		-		-
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN	$	1,372,631		-		-		1,372,631
571 MAINT OF OVERHEAD LINES	LB571	PTRAN	$	1,118,685		-		-		1,118,685
573 MAINT OF MISC. TRANSMISSION PLANT	LB573	PTRAN	$	253,946		-		-		253,946
Total Transmission Labor Expenses	LBTRAN		$	5,582,989	$	-	$	-	$	5,582,989

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
August 31, 2014

Description	Name	Functional Vector		Total System		Production Demand		Production Energy		Transmission Demand
Labor Expenses (Continued)										
Total Distribution Operation and Maintenance Labor Expenses		PDIST		-		-		-		-
Transmission and Distribution Labor Expenses				5,582,989		-		-		5,582,989
Production, Transmission and Distribution Labor Expenses	LBSUB		$	39,428,366	$	18,793,548	$	15,051,830	$	5,582,989
Customer Accounts Expense										
901 SUPERVISION/CUSTOMER ACCTS	LB901	F025	$	-		-		-		-
902 METER READING EXPENSES	LB902	F025	$	-		-		-		-
903 RECORDS AND COLLECTION	LB903	F025	$	-		-		-		-
904 UNCOLLECTIBLE ACCOUNTS	LB904	F025	$	-		-		-		-
905 MISC CUST ACCOUNTS	LB903	F025	$	-		-		-		-
Total Customer Accounts Labor Expense	LBCA		$	-	$	-	$	-	$	-
Customer Service Expense										
907 SUPERVISION	LB907	TUP	$	-		-		-		-
908 CUSTOMER ASSISTANCE EXPENSES	LB908	TUP	$	193,640		168,731		-		24,909
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	TUP	$	-		-		-		-
909 INFORMATIONAL AND INSTRUCTIONA	LB909	TUP	$	-		-		-		-
909 INFORM AND INSTRUC -LOAD MGMT	LB909x	TUP	$	-		-		-		-
910 MISCELLANEOUS CUSTOMER SERVICE	LB910	TUP	$	-		-		-		-
911 DEMONSTRATION AND SELLING EXP	LB911	TUP	$	-		-		-		-
912 DEMONSTRATION AND SELLING EXP	LB912	TUP	$	-		-		-		-
913 WATER HEATER - HEAT PUMP PROGRAM	LB913	TUP	$	-		-		-		-
915 MDSE-JOBBING-CONTRACT	LB915	TUP	$	-		-		-		-
916 MISC SALES EXPENSE	LB916	TUP	$	-		-		-		-
Total Customer Service Labor Expense	LBCS		$	193,640	$	168,731	$	-	$	24,909
Sub-Total Labor Exp	LBSUB9			39,622,006		18,962,278		15,051,830		5,607,898

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
August 31, 2014

Description	Name	Functional Vector		Total System		Production Demand		Production Energy		Transmission Demand
Labor Expenses (Continued)										
Administrative and General Expense										
920 ADMIN. & GEN. SALARIES-	LB920	LBSUB9	$	13,800,793		6,604,776		5,242,723		1,953,294
921 OFFICE SUPPLIES AND EXPENSES	LB921	LBSUB9	$	-		-		-		-
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB9	$	-		-		-		-
923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB9	$	-		-		-		-
924 PROPERTY INSURANCE	LB924	TUP	$	-		-		-		-
925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB9	$	-		-		-		-
926 EMPLOYEE BENEFITS	LB926	LBSUB9	$	304,550		145,751		115,694		43,104
928 REGULATORY COMMISSION FEES	LB928	TUP	$	-		-		-		-
929 DUPLICATE CHARGES-CR	LB929	LBSUB9	$	-		-		-		-
930 MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB9	$	-		-		-		-
931 RENTS AND LEASES	LB931	PGP	$	-		-		-		-
935 MAINTENANCE OF GENERAL PLANT	LB935	PGP	$	108,834		95,098		-		13,736
Total Administrative and General Expense	LBAG		$	14,214,177	$	6,845,625	$	5,358,417	$	2,010,135
Total Operation and Maintenance Expenses	TLB		$	53,836,183	$	25,807,904	$	20,410,246	$	7,618,033
Operation and Maintenance Expenses Less Purchase Power	LBLPP		$	53,836,183	$	25,807,904	$	20,410,246	$	7,618,033

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
August 31, 2014

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Transmission Demand
Other Expenses						
Depreciation Expenses						
Production	DEPRDP2	PPROD	$ 35,641,731	35,641,731	-	-
Transmission	DEPRDP3	PTRAN	$ 5,039,747	-	-	5,039,747
Transmission	DEPRDP4	PTRAN	$ -	-	-	-
Distribution	DEPRDP5	PDIST	$ -	-	-	-
General & Common Plant	DEPRDP6	PGP	$ 3,361,011	2,936,813	-	424,199
Other Plant	DEPROTH	TPIS	$ -	-	-	-
Total Depreciation Expense	TDEPR		$ 44,042,489	38,578,543	-	5,463,946
Property Taxes & Other	PTAX	TUP	$ 885	771	-	114
Amortization of Investment Tax Credit	OTAX	TUP	$ -	-	-	-
Other Interest Expenses	OT	TUP	$ -	-	-	-
Interest on Long Term Debt	INTLTD	TUP	$ 46,983,291	40,939,488	-	6,043,803
Interest Charged to Construction - CR		TUP	$ (2,480,401)	(2,161,329)	-	(319,072)
Other Deductions	DEDUCT	TUP	$ 591,094	515,057	-	76,037
Total Other Expenses	TOE		$ 89,137,359	$ 77,872,531	$ -	$ 11,264,827
Total Cost of Service (O&M + Other Expenses)			[redacted]			$ 30,548,394

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
August 31, 2014

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Transmission Demand
Functional Vectors						
Production Plant	F001		1.000000	1.000000	0.000000	0.000000
Transmission Plant	F002		1.000000	0.000000	0.000000	1.000000
Distribution Plant	F003		1.000000	0.000000	0.000000	1.000000
Production Plant	F017		1.000000	0.000000	1.000000	0.000000
Production Variable Cost	PROVAR		1.000000	0.000000	1.000000	0.000000
Production Fixed Cost	PROFIX		1.000000	1.000000	0.000000	0.000000
Distribution Operation Labor	F023		-	-	-	-
Distribution Maintenance Labor	F024		-	-	-	-
Customer Accounts Expense	F025		1.000000	0.000000	0.000000	1.000000
Customer Service Expense	F026		1.000000	0.000000	0.000000	1.000000
Purchased Power Energy	OMPP		1.000000	0.000000	1.000000	0.000000
Purchased Power Demand	OMPPD		1.000000	1.000000	0.000000	0.000000
Purchased Power BREC Share of HMP&L Station Two	OMPPH		[redacted]			0.000000
				-	-	0.000000
Production Energy	Energy		1.000000	0.000000	1.000000	0.000000
Internally Generated Functional Vectors						
Total Prod, Trans, and Dist Plant		PT&D	1.000000	0.873788	-	0.126212
Total Transmission Plant		PTRAN	1.000000	-	-	1.000000
Operation and Maintenance Expenses Less Purchased Power		OMLPP	1.000000	0.239517	0.709542	0.050941
Total Plant in Service		TPIS	1.000000	0.873788	-	0.126212
Total Operation and Maintenance Expenses (Labor)		TLB	1.000000	0.479378	0.379118	0.141504
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service		OMSUB2	1.000000	0.213409	0.744284	0.042307
Total Steam Power Operation Expenses (Labor)		LBSUB1	1.000000	0.851642	0.148358	-
Total Steam Power Generation Maintenance Expense (Labor)		LBSUB2	1.000000	0.149153	0.850847	-
Total Transmission Labor Expenses		LBTRAN	1.000000	-	-	1.0000000
Sub-Total Labor Exp		LBSUB7	1.000000	0.478579	0.379886	0.141535
Total General Plant		PGP	1.000000	0.873788	-	0.126212
Total Production Plant		PPROD	1.000000	1.000000	-	-
Total Intangible Plant		INTPLT	1.000000	0.873788	-	0.126212

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
August 31, 2014

Description	Ref	Name	Allocation Vector		Rurals		Large Industrials		Smelter		Total System
Plant in Service											
Power Production Plant											
Production Demand	TPIS	PLPDMD	12CP	$	859,802,270	$	228,392,044	$	713,392,532	$	1,801,586,846
Production Energy	TPIS	PLPENG	PENG	$	-	$	-	$	-	$	-
Production - Steam Direct	TPIS	PLPSTM	STMD	$	-	$	-	$	-	$	-
Total Power Production Plant		PLPT		$	859,802,270	$	228,392,044	$	713,392,532	$	1,801,586,846
Transmission Plant	TPIS	PLTRN	12CP	$	124,191,436	$	32,989,371	$	103,043,742	$	260,224,549
Distribution Substation	TPIS	PLDST	SUBA	$	-	$	-	$	-	$	-
Distribution Other	TPIS	PLDMC	Cust05	$	-	$	-	$	-	$	-
Total		PLT		$	983,993,707	$	261,381,415	$	816,436,274	$	2,061,811,395

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
August 31, 2014

Description	Ref	Name	Allocation Vector		Rurals		Large Industrials		Smelter		Total System
<u>Net Utility Plant</u>											
Power Production Plant											
Production Demand	NTPLANT	NTPDMD	12CP	$	467,190,894	$	124,101,421	$	387,636,212	$	978,928,527
Production Energy	NTPLANT	NTPENG	PENG	$	-	$	-	$	-	$	-
Production - Steam Direct	NTPLANT	NTPSTM	STMD	$	-	$	-	$	-	$	-
Total Power Production Plant		NTPT		$	467,190,894	$	124,101,421	$	387,636,212	$	978,928,527
Transmission Plant	NTPLANT	NTTRN	12CP	$	72,138,578	$	19,162,403	$	59,854,602	$	151,155,583
Distribution Substation	NTPLANT	NTDST	SUBA	$	-	$	-	$	-	$	-
Distribution Other	NTPLANT	NTDMC	Cust05	$	-	$	-	$	-	$	-
Total		NTPLT		$	539,329,473	$	143,263,823	$	447,490,814	$	1,130,084,110

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
August 31, 2014

Description	Ref	Name	Allocation Vector		Rurals		Large Industrials		Smelter		Total System
<u>Net Cost Rate Base</u>											
Power Production Plant											
Production Demand	RB	RBPDMD	12CP	$	497,763,592	$	132,222,545	$	413,002,897	$	1,042,989,034
Production Energy	RB	RBPENG	PENG	$	12,509,659	$	4,845,094	$	16,219,853	$	33,574,606
Production - Steam Direct	RB	RBPSTM	STMD	$	-	$	-	$	-	$	-
Total Power Production Plant		RBPT		$	510,273,251	$	137,067,639	$	429,222,750	$	1,076,563,640
Transmission Plant	RB	RBTRN	12CP	$	76,923,656	$	20,433,478	$	63,824,862	$	161,181,996
Distribution Substation	RB	RBDST	SUBA	$	-	$	-	$	-	$	-
Distribution Other	RB	RBDMC	Cust05	$	-	$	-	$	-	$	-
Total		RBPLT		$	587,196,907	$	157,501,117	$	493,047,612	$	1,237,745,636

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
August 31, 2014

Description	Ref	Name	Allocation Vector	Rurals	Large Industrials	Smelter	Total System
Operation and Maintenance Expenses							
Power Production Plant							
Production Demand	TOM	OMPDMD	12CP	[redacted]			
Production Demand Reallocation of Purchased Power							
Production Energy	TOM	OMPENG	PENG				
Production - Steam Direct	TOM	OMPSTM	STMD				
Total Power Production Plant		OMPT					
Transmission Plant	TOM	OMTRN	12CP	$ 9,203,028	$ 2,444,630	$ 7,635,909	$ 19,283,567
Distribution Substation	TOM	OMDST	SUBA	$ -	$ -	$ -	$ -
Distribution Other	TOM	OMDMC	Cust05	$ -	$ -	$ -	$ -
Total		OMPLT		[redacted]			

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Witness: John Wolfram

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
August 31, 2014

Description	Ref	Name	Allocation Vector		Rurals		Large Industrials		Smelter		Total System
Labor Expenses											
Power Production Plant											
Production Demand	TLB	LBPDMD	12CP	$	12,316,750	$	3,271,738	$	10,219,416	$	25,807,904
Production Energy	TLB	LBPENG	PENG	$	7,604,712	$	2,945,368	$	9,860,166	$	20,410,246
Production - Steam Direct	TLB	LBPSTM	STMD	$	-	$	-	$	-	$	-
Total Power Production Plant		LBPT		$	19,921,462	$	6,217,106	$	20,079,582	$	46,218,150
Transmission Plant	TLB	LBTRN	12CP	$	3,635,685	$	965,759	$	3,016,589	$	7,618,033
Distribution Substation	TLB	LBDST	SUBA	$	-	$	-	$	-	$	-
Distribution Other	TLB	LBDMC	Cust05	$	-	$	-	$	-	$	-
Total		LBPLT		$	23,557,147	$	7,182,865	$	23,096,172	$	53,836,183

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
August 31, 2014

Description	Ref	Name	Allocation Vector		Rurals		Large Industrials		Smelter		Total System
<u>**Depreciation Expenses**</u>											
Power Production Plant											
Production Demand	TDEPR	DPPDMD	12CP	$	18,411,502	$	4,890,706	$	15,276,335	$	38,578,543
Production Energy	TDEPR	DPPENG	PENG	$	-	$	-	$	-	$	-
Production - Steam Direct	TDEPR	DPPSTM	STMD	$	-	$	-	$	-	$	-
Total Power Production Plant		DPPT		$	18,411,502	$	4,890,706	$	15,276,335	$	38,578,543
Transmission Plant	TDEPR	DPTRN	12CP	$	2,607,653	$	692,679	$	2,163,614	$	5,463,946
Distribution Substation	TDEPR	DPDST	SUBA	$	-	$	-	$	-	$	-
Distribution Other	TDEPR	DPDMC	Cust05	$	-	$	-	$	-	$	-
Total		DPPLT		$	21,019,154	$	5,583,386	$	17,439,949	$	44,042,489

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
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12 Months Ended
August 31, 2014

Description	Ref	Name	Allocation Vector		Rurals		Large Industrials		Smelter		Total System
Property and Other Taxes											
Power Production Plant											
Production Demand	PTAX	PRPDMD	12CP	$	368	$	98	$	305	$	771
Production Energy	PTAX	PRPENG	PENG	$	-	$	-	$	-	$	-
Production - Steam Direct	PTAX	PRPSTM	STMD	$	-	$	-	$	-	$	-
Total Power Production Plant		PRPT		$	368	$	98	$	305	$	771
Transmission Plant	PTAX	PRTRN	12CP	$	54	$	14	$	45	$	114
Distribution Substation	PTAX	PRDST	SUBA	$	-	$	-	$	-	$	-
Distribution Other	PTAX	PRDMC	Cust05	$	-	$	-	$	-	$	-
Total		PRPLT		$	422	$	112	$	350	$	885

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12 Months Ended
August 31, 2014

Description	Ref	Name	Allocation Vector		Rurals		Large Industrials		Smelter		Total System
Interest Expenses											
Power Production Plant											
Production Demand	INTLTD	INPDMD	12CP	$	19,538,256	$	5,190,010	$	16,211,222	$	40,939,488
Production Energy	INTLTD	INPENG	PENG	$	-	$	-	$	-	$	-
Production - Steam Direct	INTLTD	INPSTM	STMD	$	-	$	-	$	-	$	-
Total Power Production Plant		INPT		$	19,538,256	$	5,190,010	$	16,211,222	$	40,939,488
Transmission Plant	INTLTD	INTRN	12CP	$	2,884,388	$	766,189	$	2,393,226	$	6,043,803
Distribution Substation	INTLTD	INDST	SUBA	$	-	$	-	$	-	$	-
Distribution Other	INTLTD	INDMC	Cust05	$	-	$	-	$	-	$	-
Total		INPLT		$	22,422,644	$	5,956,199	$	18,604,448	$	46,983,291

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
August 31, 2014

Description	Ref	Name	Allocation Vector	Rurals	Large Industrials	Smelter	Total System
Cost of Service Summary -- Unadjusted				$ 20,946,808	$ 8,112,872	$ 27,159,344	
				$ -	$ -	$ -	
Operating Revenues							
Sales to Members		REVUC	R01	[redacted]			
Off System Sales Revenue			OSS				
Income from Leased Property Net		OTHREV	RBPLT				
Other Operating Revenue & Income		OTHREV	RBPLT				
Total Operating Revenues		TOR		$ 161,967,568	$ 54,660,922	$ 192,430,442	$ 409,058,933
Operating Expenses							
Operation and Maintenance Expenses				[redacted]			
Depreciation and Amortization Expenses				$ 21,019,154	$ 5,583,386	$ 17,439,949	$ 44,042,489
Property and Other Taxes			NPT	$ 422	$ 112	$ 350	$ 885
Total Operating Expenses		TOE		[redacted]			
Utility Operating Margin				[redacted]			
Non-Operating Items							
Interest Income			RBPLT	$ 936,889	$ 251,297	$ 786,671	$ 1,974,858
Other Non-Operating Income			RBPLT	$ -	$ -	$ -	$ -
Other Capital Credits & Patronage Dividends			RBPLT	$ 1,283,961	$ 344,391	$ 1,078,095	$ 2,706,448
Total Non-Operating Items				$ 2,220,850	$ 595,688	$ 1,864,766	$ 4,681,305
Net Utility Operating Margin		TOM		[redacted]			
Net Cost Rate Base				[redacted]			
Rate of Return on Rate Base (Unadjusted)				-2.26%	-2.88%	-0.31%	-1.56%

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
August 31, 2014

Description	Ref	Name	Allocation Vector	Rurals	Large Industrials	Smelter	Total System
Cost of Service Summary -- Pro-Forma (Before Proposed Rate Increase)							
Operating Revenues							
Total Operating Revenue				$ 161,967,568	$ 54,660,922	$ 192,430,442	$ 409,058,933
Pro-Forma Adjustments:							
To Remove Fuel Adjustment Clause Revenue		1.01		$ (12,526,275)	$ (4,836,245)	$ (16,176,808)	$ (33,539,328)
To Remove Environmental Surcharge Revenue		1.02		$ (8,815,889)	$ (2,944,366)	$ (8,971,731)	$ (20,731,985)
To Remove Non-FAC PPA Revenue		1.03		$ 1,903,467	$ 737,229	$ 1,165,347	$ 3,806,042
Total Pro-Forma Operating Revenue				$ 142,528,872	$ 47,617,540	$ 168,447,250	$ 358,593,662

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BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
August 31, 2014

Description	Ref	Name	Allocation Vector	Rurals	Large Industrials	Smelter	Total System
Cost of Service Summary -- Pro-Forma (Before Proposed Rate Increase) (cont.)							
Operating Expenses							
Operation and Maintenance Expenses				[redacted]			
Depreciation and Amortization Expenses				$ 21,019,154	$ 5,583,386	$ 17,439,949	$ 44,042,489
Property and Other Taxes			NPT	$ 422	$ 112	$ 350	$ 885
Adjustments to Operating Expenses:							
To Remove Fuel Expense Recoverable through the FAC		1.01		$ (12,526,275)	$ (4,836,245)	$ (16,176,808)	$ (33,539,328)
To Remove Expenses Recoverable through the ES		1.02		$ (8,815,889)	$ (2,944,366)	$ (8,971,731)	$ (20,731,985)
To Remove NFPPA		1.03		$ 1,903,467	$ 737,229	$ 1,165,347	$ 3,806,042
To Remove Promotional Advertising		1.04	R01	$ (22,133)	$ (7,382)	$ (26,241)	$ (55,756)
To Remove Lobbying Expenses		1.05	R01	$ (28,154)	$ (9,390)	$ (33,379)	$ (70,923)
To Remove Economic Development Expenses		1.06	R01	$ (55,717)	$ (18,582)	$ (66,058)	$ (140,357)
To Remove Donations Expenses		1.07	R01	$ (25,139)	$ (8,384)	$ (29,805)	$ (63,328)
To Remove Touchstone Energy dues		1.08	R01	$ (52,704)	$ (17,577)	$ (62,485)	$ (132,766)
To Amortize Rate Case Expenses - Case No. 2011-00036		1.09	RBPLT	$ 96,472	$ 25,876	$ 81,004	$ 203,352
To Remove Non-Recurring Labor related to Wilson Layup		1.10	LBPLT	$ (1,135,697)	$ (346,288)	$ (1,113,473)	$ (2,595,458)
To Normalize Certain Outside Professional Services		1.11	EnergyNS	$ (192)	$ (75)	$ -	$ (267)
To Remove Forecast Demand Side Management Expenses		1.12	12CP	$ (539,916)	$ (143,420)	$ (447,978)	$ (1,131,314)
To Normalized Demand Side Management Expenses		1.12	EnergyR	$ 1,000,000	$ -	$ -	$ 1,000,000
Total Expense Adjustments				$ (20,201,877)	$ (7,568,602)	$ (25,681,608)	$ (53,452,088)
Total Operating Expenses		TOE		[redacted]			
Utility Operating Margins -- Pro-Forma				[redacted]			
Non-Operating Items				$ -	$ -	$ -	$ -
Sum of Non-Operating Items				$ 2,220,850	$ 595,688	$ 1,864,766	$ 4,681,305
Adjustments to Non-Operating Items			12CP	$ -	$ -	$ -	$ -
Total Non-Operating Items				$ 2,220,850	$ 595,688	$ 1,864,766	$ 4,681,305
Net Utility Operating Margin				[redacted]			
Net Cost Rate Base				[redacted]			
Rate of Return on Rate Base -- Pro Forma (Before Proposed Rate Increase)				-2.13%	-2.55%	0.04%	-1.32%

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BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
August 31, 2014

Description	Ref	Name	Allocation Vector	Rurals	Large Industrials	Smelter	Total System
Cost of Service Summary -- Pro-Forma (After Proposed Rate Increase)							
Operating Revenues							
Total Operating Revenue				$ 142,528,872	$ 47,617,540	$ 168,447,250	$ 358,593,662
Pro-Forma Adjustments:							
To Reflect Proposed Increase				$ 39,380,581	$ 8,220,635	$ 25,366,916	$ 72,968,131
Total Pro-Forma Operating Revenue				$ 181,909,453	$ 55,838,175	$ 193,814,166	$ 431,561,793
Operating Expenses							
Total Operating Expenses				[redacted]			
Utility Operating Margins -- Pro-Formed for Increase							
Net Cost Rate Base							
Rate of Return -- Pro Forma (After Proposed Rate Increase)				**4.19%**	**2.29%**	**4.80%**	**4.19%**
Average $/MWH Annual				57.16	48.83	51.85	53.39
Average Load Factor Monthly				0.63	0.91	0.98	0.80

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
August 31, 2014

Description	Ref	Name	Allocation Vector	Rurals	Large Industrials	Smelter	Total System
Allocation Factors							
Energy Allocation Factors							
Energy Usage by Class		E01	Energy	0.372593	0.144308	0.483099	1.000000
Customer Allocation Factors							
Rev		R01		138,121,080	46,064,053	163,756,402	347,941,535
Energy		Energy		2,436,557,000	943,698,679	3,159,206,400	6,539,462,079
FAC Revenue Allocator		FACA		2,436,557,000	943,698,679	3,159,206,400	6,539,462,079
Base Fuel Revenue Allocator		BSFL		2,436,557,000	943,698,679	3,159,206,400	6,539,462,079
Fuel Expense Applicable to FAC Allocator		FACEX		2,436,557,000	943,698,679	3,159,206,400	6,539,462,079
Energy - NonSmelter		EnergyNS		0.7208	0.2792	-	1.0000
Energy - Smelter only		EnergyS		-	-	1.0000	1.0000
Energy - Rurals only		EnergyR		1.0000	-	-	1.0000
Customers (Metering Points)		Cust05		3	1	1	5
Demand Allocators							
Steam - Direct Assignment		STMD		-	-	-	-
Substation Allocator		SUBA		-	-	-	-
Coincident Peak Demand CP		12CP		5,322,297	1,413,779	4,416,000	11,152,076
Non-Coincident Peak Demands NCP		NCP		5,376,057	1,674,594	4,416,000	11,466,651

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
August 31, 2014

Description	Ref	Name	Allocation Vector	Rurals	Large Industrials	Smelter	Total System
Production Energy Allocation							
Production Energy Residual Allocator		PENGA		2,436,557,000	943,698,679	3,159,206,400	6,539,462,079
Production Energy Costs				-	-	-	-
Member Specific Assignment				-	-	-	-
Production Energy Residual			PENGA	103,990,956	40,276,557	134,833,248	279,100,761
Production Energy Total		PENGT		103,990,956	40,276,557	134,833,248	279,100,761
Production Energy Total Allocator		PENG	PENGT	0.372593	0.144308	0.483099	1.000000
FAC Expense Residual Allocator		FACALL		2,436,557,000	943,698,679	3,159,206,400	6,539,462,079
FAC Expense Cost				-	-	-	-
Member Specific Assignment				-	-	-	-
FAC Expense Residual			FACALL	-	-	-	-
FAC Expense Total		FACT		-	-	-	-
FAC Expense Allocator		FACAL	12CP	0.372593	0.144308	0.483099	1.000000
OSS Allocated Amount		OSSA		[redacted]			
Off-System Sales Allocator				[redacted]			
Off-System Sales Revenue			OSSA				
Specific Assignment							
Total OSS Assignments		OSS		-	-	-	-

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
August 31, 2014

Description	Ref	Name	Allocation Vector	Rurals	Large Industrials	Smelter	Total System
Operating Expenses							
Expenses before Adjustments				[redacted]			
Production Demand							
Production Energy				$ 11,810,735	$ 3,137,324	$ 9,799,568	$ 24,747,627
Transmission Demand				[redacted]			
Total							
Expenses After Revenue Offsets				[redacted]			
Production Demand							
Production Energy				$ 11,810,735	$ 3,137,324	$ 9,799,568	$ 24,747,627
Transmission Demand				[redacted]			
Total							
Rate Base				[redacted]			
Production Demand							
Production Energy				$ 76,923,656	$ 20,433,478	$ 63,824,862	$ 161,181,996
Transmission Demand				[redacted]			
Total							
Operating Expenses-Unit Costs				[redacted]			
Production Demand ($/kW)							
Production Energy ($/kWh)				2.22	2.22	2.22	2.22
Transmission Demand ($/kW)							
Rate Base-Unit Costs				[redacted]			
Production Demand ($/kW)							
Production Energy ($/kWh)				14.45	14.45	14.45	14.45
Transmission Demand ($/kW)							

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
August 31, 2014

Description	Ref	Name	Allocation Vector	Rurals	Large Industrials	Smelter	Total System
Revenue Requirement Assuming a Rate of Return of	4.19%			[redacted]			
Production Demand				[redacted]			
Production Energy				15,037,290	3,994,404	12,476,695	31,508,389
Transmission Demand				[redacted]			
Total Revenue Requirement				[redacted]			
Unit Revenue Requirement							
Production Demand				[redacted]			
Production Demand (Per kW)				[redacted]			
Production Demand Margin (Per kW)				[redacted]			
Total Production Demand (Per kW)				[redacted]			
Production Energy				[redacted]			
Production Energy - (Per kWh)				[redacted]			
Production Energy Margin - (Per kWh)				[redacted]			
Total Production Energy (Per kWh)				[redacted]			
Transmission Demand							
Transmission Demand (per kW)				2.22	2.22	2.22	2.22
Tranmission Margin (Per kW)				0.02	0.02	0.02	0.02
Total Transmission Demand (per kW)				2.24	2.24	2.24	2.24

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Billing Determinants - Present and Proposed Rates

12 Months Ended
August 31, 2014

Rate		Billing Determinants		Current Rate Charge		Current Rate Billings	Proposed Rate Charge		Proposed Rate Billings	Variance Billings
Rural Delivery Point Service										
Demand Charge	CP	5,322,297	kW-Mo	9.697	/kW-Mo	$ 51,610,313	16.848	/kW-Mo	$ 89,670,057	$ 38,059,745
Energy Charge		2,436,557,000	kWh	$ 0.029736	/kWh	72,453,459	$ 0.030000	/kWh	73,096,710	643,251
Total Demand and Energy Charges				0.050918		$ 124,063,772	0.066802		$ 162,766,767	$ 38,702,996
Non-Smelter Non-FAC PPA				(0.000781)		(1,903,467)	(0.000781)		(1,903,467)	-
FAC				0.005141		12,526,275	0.005141		12,526,275	-
Environmental Surcharge				0.003618		8,815,889	0.003894		9,488,521	672,632
Surcredit				(0.001738)		(4,235,358)	(0.001738)		(4,235,358)	-
Total		2,436,557,000	kWh	0.057157		$ 139,267,110	0.073318		$ 178,642,738	$ 39,375,628
Increase $									$ 39,375,628	
Increase %									28.3%	
Large Industrial Customer Delivery Point Service										
Demand Charge	NCP	1,674,594	kW-Mo	10.50	/kW-Mo	$ 17,583,237	12.330	/kW-Mo	$ 20,647,744	$ 3,064,507
Energy Charge		943,698,679	kWh	$ 0.024508	/kWh	23,128,167	$ 0.030000	/kWh	$ 28,310,960	$ 5,182,793
Total Demand and Energy Charges				0.043140		$ 40,711,404			$ 48,958,704	$ 8,247,300
Non-Smelter Non-FAC PPA				(0.000781)		(737,229)	(0.000781)		(737,229)	-
FAC				0.005125		4,836,245	0.005125		4,836,245	-
Environmental Surcharge				0.003120		2,944,366	0.003092		2,917,700	(26,666)
Surcredit				(0.001777)		(1,677,110)	(0.001777)		(1,677,110)	-
Total		943,698,679	kWh	0.048827		$ 46,077,677	0.057538		$ 54,298,312	$ 8,220,635
Increase $									$ 8,220,635	
Increase %									17.8%	

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Billing Determinants - Present and Proposed Rates

12 Months Ended
August 31, 2014

Rate	Billing Determinants		Current Rate Charge		Current Rate Billings	Proposed Rate Charge		Proposed Rate Billings	Variance Billings
Smelter									
Base Energy Charge									
Base Fixed Energy Charge	3,159,206,400	kWh	0.039435	/kWh	$ 124,583,304	$ 0.047485	/kWh	$ 150,014,916	$ 25,431,612
Base Variable Energy Charge	-	kWh	0.021806	/kWh	-	$ 0.021806	/kWh	-	-
Total Base Energy Charge	3,159,206,400	kWh	0.039435		$ 124,583,304			$ 150,014,916	$ 25,431,612
Other Charges or Credits									
TIER Adjustment Charge			0.002950		$ 9,319,659	0.002950		$ 9,319,659	$ -
Non-FAC PPA			(0.000369)		$ (1,165,347)	(0.000369)		$ (1,165,347)	-
FAC			0.005121		$ 16,176,808	0.005121		$ 16,176,808	-
Environmental Surcharge			0.002840		$ 8,971,731	0.002819		$ 8,907,035	(64,696)
Surcharge			0.001872		$ 5,912,468	0.001872		$ 5,912,468	-
Total	3,159,206,400		0.051848		$ 163,798,623	0.059878		$ 189,165,538	$ 25,366,916
Increase $								$ 25,366,916	
Increase %								15.5%	
TOTAL	6,539,462,079		0.053390		$ 349,143,410	0.064548		$ 422,106,588	$ 72,963,178
INCREASE						0.011157		$ 72,963,178 20.90%	99.99%

Case No. 2012-00535
Attachment for Response to PSC 2-36 - Exhibit Wolfram-5.2
Witness: John Wolfram

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Billing Determinants - Present and Proposed Rates

12 Months Ended
August 31, 2014

Rate		Billing Determinants	Current Rate Charge	Current Rate Billings	Proposed Rate Charge	Proposed Rate Billings	Variance Billings
Notes	Note A:	Base Rate is the rate resulting from the application of the Large Industrial Rate to a load with a 98% load factor, plus $0.0025/kWh.					
			Current		*Proposed*		
		Large Industrial Demand Charge	10.50		12.330		
		Hours {730 hrs * 98%}	715.4		715.4		
		Demand Charge per kWh	$ 0.014677		$ 0.017235		
		Energy Charge	0.024508		0.030000		
		Plus:	0.000250		0.000250		
		Total	$ 0.039435		$ 0.047485		
	Note B:	Base Variable Energy Charge equals the total of the FAC Base, Environmental Surcharge Base, and Non-FAC PPA Base					
		FAC Base	$ 0.020932		$ 0.020932		
		Environmental Surcharge Base	-		-		
		Non-FAC PPA Base	0.000874		0.000874		
		Total Base Variable Energy Charge	$ 0.021806		$ 0.021806		
	Note C:	Values for ES are incorporated from the Big Rivers Financial Model					
	Note D:	Retail rate increases estimated using approximate distribution cost adder					
		RDS Distr Adder	0.03300				
		LIC Dist Adder	0.00200				
		RDS	0.090157		0.106318		0.016160 17.9%
		LIC	0.050827		0.059538		0.008711 17.1%

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Summary of Proposed Increase

12 Months Ended
August 31, 2014

Class	Total Revenue at Current Rates ($)	Total Revenue at Proposed Rates ($)	Increase ($)	Increase (%)
Rural	139,267,110	178,642,738	39,375,628	28.3%
Large Industrial	46,077,677	54,298,312	8,220,635	17.8%
Smelter	163,798,623	189,165,538	25,366,916	15.5%
Total	349,143,410	422,106,588	72,963,178	20.9%

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Estimate of Retail Rate Increase

12 Months Ended
August 31, 2014

		Current	Proposed	Increase	Increase
Rural Delivery Service					
Estimated Retail Rate ($/kWh)					
All-In Wholesale Rate		0.057157	0.073318	0.016160	28.3%
Estimated Retail Distr Cost Adder		0.033000	0.033000		
Total Retail Rate Estimate		0.090157	0.106318	0.016160	17.9%
Estimated Billings ($/Month)					
Monthly Usage	100 kWh	$ 9.02	$ 10.63	$ 1.61	17.8%
	200	$ 18.03	$ 21.26	$ 3.23	17.9%
	300	$ 27.05	$ 31.90	$ 4.85	17.9%
	400	$ 36.06	$ 42.53	$ 6.47	17.9%
	500	$ 45.08	$ 53.16	$ 8.08	17.9%
	600	$ 54.09	$ 63.79	$ 9.70	17.9%
	700	$ 63.11	$ 74.42	$ 11.31	17.9%
	800	$ 72.13	$ 85.05	$ 12.92	17.9%
	900	$ 81.14	$ 95.69	$ 14.55	17.9%
	1000	$ 90.16	$ 106.32	$ 16.16	17.9%
	1100	$ 99.17	$ 116.95	$ 17.78	17.9%
	1200	$ 108.19	$ 127.58	$ 19.39	17.9%
	1300	$ 117.20	$ 138.21	$ 21.01	17.9%
	1400	$ 126.22	$ 148.84	$ 22.62	17.9%
	1500	$ 135.24	$ 159.48	$ 24.24	17.9%

Large Industrial Customer Service					
Estimated Retail Rate ($/kWh)					
All-In Wholesale Rate		0.048827	0.057538	0.008711	17.8%
Estimated Retail Distribution Cost Adder		0.002000	0.002000		
Total Retail Rate Estimate		0.050827	0.059538	0.008711	17.1%
Estimated Billings ($/Month)					
Monthly Usage	500 kWh	$ 25.41	$ 29.77	$ 4.36	17.1%
	600	$ 30.50	$ 35.72	$ 5.23	17.1%
	700	$ 35.58	$ 41.68	$ 6.10	17.1%
	800	$ 40.66	$ 47.63	$ 6.97	17.1%
	900	$ 45.74	$ 53.58	$ 7.84	17.1%
	1000	$ 50.83	$ 59.54	$ 8.71	17.1%
	1100	$ 55.91	$ 65.49	$ 9.58	17.1%
	1200	$ 60.99	$ 71.45	$ 10.45	17.1%
	1300	$ 66.07	$ 77.40	$ 11.32	17.1%
	1400	$ 71.16	$ 83.35	$ 12.20	17.1%
	1500	$ 76.24	$ 89.31	$ 13.07	17.1%
	1600	$ 81.32	$ 95.26	$ 13.94	17.1%
	1700	$ 86.41	$ 101.21	$ 14.81	17.1%
	1800	$ 91.49	$ 107.17	$ 15.68	17.1%
	1900	$ 96.57	$ 113.12	$ 16.55	17.1%
	2000	$ 101.65	$ 119.08	$ 17.42	17.1%

BIG RIVERS ELECTRIC CORPORATION

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

Response to Commission Staff's Second Request for Information
dated February 14, 2013

February 28, 2013

Item 37) ***Refer to Exhibit Wolfram-4, page 9 of 16. Reconcile the amounts in the line item "Sales to Members" with the Total of the Current Rate Billings column for each of the rate classes in Exhibit Wolfram-5, pages 1 and 2.***

Response) See attached variance analysis. The difference between the "Sales to Members" in Exhibit Wolfram-4 and the Total of the Current Rate Billings in Exhibit Wolfram-5 is almost entirely attributable to the differences in Environmental Surcharge revenues described in response to PSC 2-40. The additional variance of $328 for the Smelter energy charge is due to rounding. These variances are addressed in the response to PSC 2-36.

Witness) John Wolfram

Big Rivers Electric Corporation
Case No. 2012-00535

Attachment to Response for PSC 2-37
Reconciliation of Sales To Members / Total Billings

Line	Exhibit	Item	Rurals	Large Industrials	Smelter	Total
1	Exhibit Wolfram-4	Base Demand	[redacted]			
2		Base Energy				
3		FAC				
4		ES				
5		NFPPA				
6		Surcharge				
7		TIER Adj				
8		TOTAL				
9						
10						
11	Exhibit Wolfram-5	Base Demand	$ 50,561,820	$ 17,583,237	$ -	$ 68,145,057
12		Base Energy	$ 72,453,459	$ 23,125,336	$ 124,573,827	$ 220,152,622
13		FAC	$ 12,526,275	$ 4,836,245	$ 16,176,808	$ 33,539,328
14		ES	$ 8,718,352	$ 2,933,572	$ 8,938,660	$ 20,590,584
15		NFPPA	$ (1,903,467)	$ (737,229)	$ (1,165,347)	$ (3,806,042)
16		Surcharge	$ (4,235,358)	$ (1,677,110)	$ 5,912,468	$ -
17		TIER Adj	$ -	$ -	$ 9,319,659	$ 9,319,659
18		TOTAL	$ 138,121,080	$ 46,064,053	$ 163,756,075	$ 347,941,208
19						
20						
21	Variance	Base Demand	[redacted]			
22		Base Energy				
23		FAC				
24		ES				
25		NFPPA				
26		Surcharge				
27		TIER Adj				
28		TOTAL				

Item 38) ***Refer to Exhibit Wolfram-4, pages 9 and 11 of 16.***

a. Explain why the amounts in line item "Net Cost Rate Base" are redacted on these pages when the amounts appear on page 3 of 16 of this exhibit.

b. If the answer to a. above is that the amounts do not need to be redacted on pages 9 and 11 , explain why the amounts in line item "Net Utility Operating Margin" should be redacted on these pages given that they can be calculated by multiplying the "Net Cost Rate Base" by the "Rate of Return on Rate Base."

c. If Big Rivers agrees that the amounts for line items "Net Cost Rate Base" and "Net Utility Operating Margin" need not be redacted, provide an updated Exhibit Wolfram-4, pages 9 and I 1 of 16, with the amounts un-redacted.

Response)

a. The amounts in the Net Cost Rate Base lines on pages 9 and 11 of Exhibit Wolfram-4, while not otherwise confidential, were redacted because they could readily be used with other information on those same pages to calculate or back into confidential information on those pages. Big Rivers did not redact numbers on page 3 of Exhibit Wolfram-4 because it was not apparent that someone would know that numbers on that page could be used to back into confidential information on pages 9 and 11 or that they would know which numbers to use. It is still not apparent that, without seeing the redacted numbers, someone would know which numbers from page 3 to use, and for this reason, Big Rivers still seeks confidential treatment of the Net Cost Rate Base amounts on pages 9 and 11 of Exhibit Wolfram-4.

b. Not applicable.

c. Not applicable.

Witness) John Wolfram

BIG RIVERS ELECTRIC CORPORATION

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

Response to Commission Staff's Second Request for Information dated February 14, 2013

February 28, 2013

Item 39) ***Refer to Exhibit Wolfram-4, page 11 of 16.***

a. Explain why the adjustments to remove 1) fuel expense recoverable through the fuel adjustment clause ("FAC"); 2) expense recoverable through the environmental surcharge; 3) Non-FAC PPA; and 4) lobbying expenses differ from the same titled adjustments on Exhibit Wolfram-2, page 1 of 14.

b. Reconcile the "Total Operating Expenses" on this page with Exhibit Wolfram-2, page 1 of 14, Adjusted Cost of Service of $423,330,643.

Response)

a. The values in Exhibit Wolfram-4, page 11 of 16, for the FAC, ES, Non-FAC PPA, and lobbying expenses should not differ from the same titled adjustments in Exhibit Wolfram-2. The values in Exhibit Wolfram-2 are correct, and the values in Exhibit Wolfram-4 page 11 should be revised to match those amounts. This is addressed in response to PSC 2-36.

b. See attached. The differences in the reconciliation stem from the expense adjustments identified in response to part a. Note that the variance in expense adjustments is almost entirely offset by the variance in revenue adjustments, as shown in the last line of the attachment, so the effect on the COSS results is negligible.

Witness) John Wolfram

Big Rivers Electric Corporation
Case No. 2012-00535

Attachment to Response for PSC 2-39
Reconciliation of Total Cost of Service / Total Operating Expenses
Exhibit Wolfram-4 and Exhibit Wolfram-2

Line	Exhibit	Item	Reference		Amount
1					
2	Exhibit Wolfram-4	Total Operating Expenses	Exhibit Wolfram-4 Page 9	[redacted]	
3		Interest on Long Term Debt	Exhibit Wolfram-3 Page 13	$	46,983,291
4		Interest Charged to Construction - CR	Exhibit Wolfram-3 Page 13	$	(2,480,401)
5		Other Deductions	Exhibit Wolfram-3 Page 13	$	591,094
6		Subtotal	Lines 2 + 3 + 4 + 5	[redacted]	
7					
8		Expense Adjustments	Exhibit Wolfram-4 Page 11	$	(52,870,386)
9		Subtotal	Lines 6 + 8	[redacted]	
11					
12	Exhibit Wolfram-2	Total Cost of Service	Exhibit Wolfram-2 Page 1	$	478,313,780
13		Expense Adjustments	Exhibit Wolfram-2 Page 1	$	(54,983,137)
14		Adjusted Cost of Service	Exhibit Wolfram-2 Page 1	$	423,330,643
15					
16	Variance	Total Adjusted Cost of Service	Line 9 - 14	[redacted]	
17		Variance in Expense Adjustments	Line 8 - 13	$	2,112,751
18		Variance Unrelated to Expense Adj	Line 16 - 17	[redacted]	
19					
20					
21	Exhibit Wolfram-4	Revenue Adjustments	Exhibit Wolfram-4 Page 10	$	(50,323,870)
22		Expense Adjustments	Exhibit Wolfram-4 Page 11	$	(52,870,386)
23		Net Adjustment	Line 22 -21	$	(2,546,516)
24					
25	Exhibit Wolfram-2	Revenue Adjustments	Exhibit Wolfram-2 Page 1	$	(52,433,722)
26		Expense Adjustments	Exhibit Wolfram-2 Page 1	$	(54,983,137)
27		Net Adjustment	Line 26 -25	$	(2,549,415)
28					
29	Variance	Revenue Adjustments	Line 21 - 25	$	2,109,852
30		Expense Adjustments	Line 22 - 26	$	2,112,751
31		Net Adjustment	Line 30 - 29	$	2,899

BIG RIVERS ELECTRIC CORPORATION

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

Response to Commission Staff's Second Request for Information dated February 14, 2013

February 28, 2013

Item 40) ***Refer to Exhibit Wolfram-5.***

a. Refer to page 1 of 4.

1) Explain why the Rural Proposed Rate Billings show a total \$90,190,052 for the Demand Charge rather than \$90,212,934 (calculated by multiplying 5,322,297 kW times \$16.95).

2) Explain why the LIC Proposed Rate Billings show a total \$20,788,374 for the Demand Charge rather than \$20,781,711 (calculated by multiplying 1,674,594 kW times \$12.41).

3) Explain why, under the Proposed Rate, the Environmental Surcharge rate of \$.003744 for the Rural class and \$.002957 for the LIC class do not reconcile with the Test Period Total column on Exhibit Siewert-2, page 25, line 26, and page 26, line 43, respectively.

b. Refer to page 2 of 4. Explain why, under the Proposed Rate, the Environmental Surcharge rate of \$.002746 for the Smelter class does not reconcile with the Test Period Total column on Exhibit Siewert-2, page 27, line 69.

c. Refer to page 3 of 4, Note A. Under the proposed column, explain why the Demand Charge per kWh should not be \$.017347 (calculated by dividing 12.41 by 715.4) instead

of the $.017353 shown. If the Demand Charge should be $.017347, explain why the total charge should not be $.047597 rather than the $.047603 shown.

d. Refer to page 3 of 4, Note B. Under the proposed rate column, did Big Rivers intend to show the FAC base as $.020932 rather than $.01072 and a Total Base Variable Energy Charge of $.021806 rather than $.011594? If yes, confirm that this amount should appear as the current charge as well as the proposed charge on this page. If no, explain the origin of the $.01072 FAC base.

e. Refer to page 4 of 4. Confirm that the last column on this page indicates that, on top of the increase proposed in base rates, the Rural class will experience an additional increase in environmental costs of $404,795 due to the proposed increase in base rates. If this cannot be confirmed, explain.

Response) The differences noted herein stem from rounding, significant digits, and minor differences between the modeling of the Environmental Surcharge in the COSS and the Big Rivers Financial Model. These variances are addressed in the response to PSC 2-36.

a. (1) and (2) The difference is rounding error. The rates in Exhibit Wolfram-5 were not rounded, but instead were carried out in the worksheet to more significant digits than are shown in the printed exhibit.

(3) The Environmental Surcharge ("ES") values in the COSS were developed separately from those in the Big Rivers Financial Model described by Mr. Siewert. The Big Rivers Financial Model captures the impact of the recent change in the ES tariff (i.e. the move from a "per kWh based" charge to a "percentage of revenue" charge) with greater specificity than the estimate of ES revenues in the COSS.

b. Please see the response to (a)(3) above.

c. Please see the response to (a)(1) and (2) above.

d. Confirmed. Note that the Total Base Variable Energy Charge in Note B has no impact because the Base Variable kWh is zero in the fully forecasted test period.

e. Confirmed. The Rural rate class will experience an increase in ES costs as well as an increase in base rates, because the ES tariff is now a "percentage-of-revenue" charge rather than a "per kWh" charge, and because the Rural rate class comprises a larger portion of Big Rivers' total jurisdictional revenues in the fully forecasted test period (after the Century contract termination) than they do at present.

Witness) John Wolfram

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

Response to Commission Staff's Second Request for Information dated February 14, 2013

February 28, 2013

PSC 2-41) ***State whether Big Rivers has any facilities, including coal handing facilities, that are included in rate base but no longer used and useful.***

Response) Big Rivers does not have any facilities, including coal handling facilities, included in its rate base that are no longer used and useful.

Witness) Robert W. Berry