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ATTORNEYS AT LAW

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*Also Licensed in Indiana



September 9, 2014

**Via Federal Express**

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

Re: In the Matter of: 2014 Integrated Resource Plan of Big Rivers Electric Corporation, P.S.C. Case No. 2014-00166

Dear Mr. Derouen:

Enclosed for filing are an original and ten (10) copies of: (i) Big Rivers Electric Corporation's responses to the Initial Requests for Information from the Kentucky Public Service Commission Staff, the Attorney General and Ben Taylor and Sierra Club; (ii) a petition for confidential treatment; and (iii) a motion for deviation. I certify that on this date, a copy of this letter, a copy of the responses, a copy of the petition, and a copy of the motion were served on each of the persons listed on the attached service list by either first-class mail or by overnight courier service.

Sincerely,

Tyson Kamuf

TAK/lm
Enclosures

cc. Service List
Bob Berry
Billie Richert
DeAnna Speed
Burns Mercer
G. Kelly Nuckols
Greg Starheim

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**BIG RIVERS ELECTRIC CORPORATION**

**2014 INTEGRATED RESOURCE PLAN OF**
**BIG RIVERS ELECTRIC CORPORATION**
**CASE NO. 2014-00166**

## VERIFICATION

I, Billie J. Richert, verify, state, and affirm that the data request responses filed with this verification for which I am listed as a witness 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 3 day of September, 2014.

Mary Borders (Arnett)

Notary Public, Ky. State at Large
My Commission Expires 8/8/2016

**BIG RIVERS ELECTRIC CORPORATION**

**2014 INTEGRATED RESOURCE PLAN OF**
**BIG RIVERS ELECTRIC CORPORATION**
**CASE NO. 2014-00166**

## VERIFICATION

I, James R. (Jim) Garrett, verify, state, and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

James R. (Jim) Garrett

COMMONWEALTH OF KENTUCKY )
COUNTY OF HENDERSON )

SUBSCRIBED AND SWORN TO before me by James R. (Jim) Garrett on this the 3rd day of September, 2014.

Notary Public, Ky. State at Large
My Commission Expires_____

Notary Public, Kentucky State-At-Large
My Commission Expires: July 3, 2018
ID 513528

**BIG RIVERS ELECTRIC CORPORATION**

**2014 INTEGRATED RESOURCE PLAN OF**
**BIG RIVERS ELECTRIC CORPORATION**
**CASE NO. 2014-00166**

**VERIFICATION**

I, Lindsay N. Barron, verify, state, and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Lindsay N. Barron

COMMONWEALTH OF KENTUCKY )
COUNTY OF HENDERSON )

SUBSCRIBED AND SWORN TO before me by Lindsay N. Barron on this the 3RD day of September, 2014.

Notary Public, Ky. State at Large
My Commission Expires 03-03-2018

**BIG RIVERS ELECTRIC CORPORATION**

**2014 INTEGRATED RESOURCE PLAN OF**
**BIG RIVERS ELECTRIC CORPORATION**
**CASE NO. 2014-00166**

## VERIFICATION

I, Eric M. Robeson, verify, state, and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Eric M. Robeson

COMMONWEALTH OF KENTUCKY )
COUNTY OF HENDERSON )

SUBSCRIBED AND SWORN TO before me by Eric M. Robeson on this the 3RD day of September, 2014.

Notary Public, Ky. State at Large
My Commission Expires 03-03-2018

**BIG RIVERS ELECTRIC CORPORATION**

**2014 INTEGRATED RESOURCE PLAN OF**
**BIG RIVERS ELECTRIC CORPORATION**
**CASE NO. 2014-00166**

## VERIFICATION

I, Marlene S. Parsley, verify, state, and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Marlene S Parsley
Marlene S. Parsley

COMMONWEALTH OF KENTUCKY )
COUNTY OF HENDERSON )

SUBSCRIBED AND SWORN TO before me by Marlene S. Parsley on this the 3RD day of September, 2014.

Vikie G. King
Notary Public, Ky. State at Large
My Commission Expires 03-03-2018

**BIG RIVERS ELECTRIC CORPORATION**

**2014 INTEGRATED RESOURCE PLAN OF**
**BIG RIVERS ELECTRIC CORPORATION**
**CASE NO. 2014-00166**

**VERIFICATION**

I, Christopher S. (Chris) Bradley, verify, state, and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Christopher S. (Chris) Bradley

COMMONWEALTH OF KENTUCKY )
COUNTY OF HENDERSON )

SUBSCRIBED AND SWORN TO before me by Christopher S. (Chris) Bradley on this the 3 day of September, 2014.

Notary Public, Ky. State at Large
My Commission Expires 8/8/2016

**BIG RIVERS ELECTRIC CORPORATION**

**2014 INTEGRATED RESOURCE PLAN OF**
**BIG RIVERS ELECTRIC CORPORATION**
**CASE NO. 2014-00166**

**VERIFICATION**

I, Nicholas R. (Nick) Castlen, verify, state, and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Nicholas R. (Nick) Castlen

COMMONWEALTH OF KENTUCKY )
COUNTY OF HENDERSON )

SUBSCRIBED AND SWORN TO before me by Nicholas R. (Nick) Castlen on this the 3rd day of September, 2014.

Notary Public, Ky. State at Large
My Commission Expires 8/8/2016

**BIG RIVERS ELECTRIC CORPORATION**

**2014 INTEGRATED RESOURCE PLAN OF**
**BIG RIVERS ELECTRIC CORPORATION**
**CASE NO. 2014-00166**

## VERIFICATION

I, Jeffrey R. (Jeff) Williams, verify, state, and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Jeffrey R. (Jeff) Williams

COMMONWEALTH OF KENTUCKY )
COUNTY OF HENDERSON )

SUBSCRIBED AND SWORN TO before me by Jeffrey R. (Jeff) Williams on this the 3rd day of September, 2014.

Notary Public, Ky. State at Large
My Commission Expires 03-03-2018

**BIG RIVERS ELECTRIC CORPORATION**

**2014 INTEGRATED RESOURCE PLAN OF**
**BIG RIVERS ELECTRIC CORPORATION**
**CASE NO. 2014-00166**

**VERIFICATION**

I, Christopher A. (Chris) Warren, verify, state, and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Christopher A. (Chris) Warren

COMMONWEALTH OF KENTUCKY )
COUNTY OF HENDERSON )

SUBSCRIBED AND SWORN TO before me by Christopher A. (Chris) Warren on this the 3 day of September, 2014.

Notary Public, Ky. State at Large
My Commission Expires 8/8/2016

**BIG RIVERS ELECTRIC CORPORATION**

**2014 INTEGRATED RESOURCE PLAN OF**
**BIG RIVERS ELECTRIC CORPORATION**
**CASE NO. 2014-00166**

## VERIFICATION

I, Russell L. (Russ) Pogue, verify, state, and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Russell L. (Russ) Pogue

COMMONWEALTH OF KENTUCKY )
COUNTY OF HENDERSON )

SUBSCRIBED AND SWORN TO before me by Russell L. (Russ) Pogue on this the 3RD day of September, 2014.

Notary Public, Ky. State at Large
My Commission Expires 03-03-2018

**BIG RIVERS ELECTRIC CORPORATION**

**2014 INTEGRATED RESOURCE PLAN OF**
**BIG RIVERS ELECTRIC CORPORATION**
**CASE NO. 2014-00166**

**VERIFICATION**

I, Duane E. Braunacker, verify, state, and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Duane E. Braunacker

Duane E. Braunacker

COMMONWEALTH OF KENTUCKY )
COUNTY OF HENDERSON )

SUBSCRIBED AND SWORN TO before me by Duane E. Braunacker on this the 3rd day of September, 2014.

Vikie G. King

Notary Public, Ky. State at Large
My Commission Expires 03-03-2018

**BIG RIVERS ELECTRIC CORPORATION**

**2014 INTEGRATED RESOURCE PLAN OF**
**BIG RIVERS ELECTRIC CORPORATION**
**CASE NO. 2014-00166**

## VERIFICATION

I, John W. Hutts, verify, state, and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

John W. Hutts

STATE OF GEORGIA )
COUNTY OF COBB )

SUBSCRIBED AND SWORN TO before me by John W. Hutts on this the 17TH day of August, 2014.

Notary Public, GA State at Large
My Commission Expires 2/10/2015

K RUDITYS
MY COMMISSION EXPIRES
FEB.
10
2015
COBB CO., GEORGIA
NOTARY PUBLIC

**BIG RIVERS ELECTRIC CORPORATION**

**2014 INTEGRATED RESOURCE PLAN OF**
**BIG RIVERS ELECTRIC CORPORATION**
**CASE NO. 2014-00166**

## VERIFICATION

I, Brian D. Smith, verify, state, and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Brian D. Smith

STATE OF GEORGIA )
COUNTY OF COBB )

SUBSCRIBED AND SWORN TO before me by Brian D. Smith on this the 27th day of August, 2014.

Notary Public, GA State at Large
My Commission Expires 2/10/2015

ORIGINAL



Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

**COMMONWEALTH OF KENTUCKY**

**BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

**In the Matter of:**

| | | |
|---|---|---|
| **BIG RIVERS ELECTRIC CORPORATION**<br>**2014 INTEGRATED RESOURCE PLAN** | )<br>)<br>) | **Case No.**<br>**2014-00166** |

**Response to the Commission Staff's**
**Initial Request for Information**
**dated August 20, 2014**

**FILED:** **September 10, 2014**

ORIGINAL

**BIG RIVERS ELECTRIC CORPORATION**

**2014 INTEGRATED RESOURCE PLAN**
**OF BIG RIVERS ELECTRIC CORPORATION**
**CASE NO. 2014-00166**

**Response to Commission Staff's**
**Initial Request for Information**
**Dated August 20, 2014**

**September 10, 2014**

**Item 1)** **Refer to footnote 14 on page 17 of the 2014 Integrated Resource Plan ("IRP"), which refers to over 200 measure permutations. Page 4 of the Demand-Side Management ("DSM") Potential Study ("Study") indicates that nearly 400 energy-efficiency ("EE") measure permutations were examined. Explain the discrepancy in the number of measure permutations.**

**Response)** The footnote on page 14 of the IRP discusses the 200 measure permutations which were found to be cost effective by the DSM Study and applicable to the energy efficiency programs in the Big Rivers DSM portfolio. These programs are listed on page 60 of the IRP. Part 4 of the Study refers to the full set of measure permutations included in the Study. Some of these nearly 400 permutations were found to be either not cost effective or not appropriate for inclusion in any of the existing energy efficiency programs in the DSM portfolio.

**Witness)** Russ Pogue

**BIG RIVERS ELECTRIC CORPORATION**

**2014 INTEGRATED RESOURCE PLAN**
**OF BIG RIVERS ELECTRIC CORPORATION**
**CASE NO. 2014-00166**

**Response to Commission Staff's**
**Initial Request for Information**
**Dated August 20, 2014**

**September 10, 2014**

**Item 2) Refer to footnote 15 on page 17 of the 2014 IRP where it states that GDS Associates, Inc. ("GDS") used the Mid-Atlantic Technical Reference Manual ("Manual").**

**a. Identify the states whose information is included in the Manual.**

**b. Explain why the Manual was chosen over other regions' technical reference manuals.**

**Response)**

a. The Manual is produced and updated by the Northeast Energy Efficiency Partnerships group, which represents the following Northeast and Mid-Atlantic states: Maryland, Delaware, District of Columbia, Pennsylvania, New Jersey, New York, Connecticut, Massachusetts, Rhode Island, Vermont, New Hampshire, and Maine. Therefore, it is assumed that the information is generally applicable to these Northeast and Mid-Atlantic states, and is applicable to other states on a case-by-case basis (e.g. savings algorithms can sometimes be universally applied across all states).

b. The Study relied foremost on any data that was available in the Indiana Technical Resource Manual ("Indiana TRM") because this source was the most current and regionally applicable document of its kind that was available at the time of the Study.

The Mid-Atlantic Technical Reference Manual was used as a secondary source in some instances for information such as measure savings algorithms, if the Indiana TRM did not provide necessary data. The Mid-Atlantic Technical Reference Manual was used as a secondary source because the Mid-Atlantic TRM is an industry accepted source of energy efficiency information, and was only used when it was determined to be the best remaining available option for source data.

**Witness)** Russ Pogue

**BIG RIVERS ELECTRIC CORPORATION**

**2014 INTEGRATED RESOURCE PLAN**
**OF BIG RIVERS ELECTRIC CORPORATION**
**CASE NO. 2014-00166**

**Response to Commission Staff's**
**Initial Request for Information**
**Dated August 20, 2014**

**September 10, 2014**

**Item 3)** **Refer to the first full paragraph on page 18 of the IRP where it states that "Big Rivers evaluates the cost-effectiveness of specific DSM measures when determining which DSM programs to implement." Provide a breakdown of the value assigned to each benefit and cost for each year of the IRP planning period and explain how the value was determined.**

**Response)** All specific measure benefits, costs and sources are documented in Appendix A (Residential Measure Detail) and Appendix B (Commercial and Industrial Measure Detail) of Appendix B of the 2014 DSM Potential Study. The benefits and costs in both Appendix A and Appendix B are deemed to be effective for the life of each individual measure listed in the same appendix.

**Witness)** Russ Pogue

**BIG RIVERS ELECTRIC CORPORATION**

**2014 INTEGRATED RESOURCE PLAN**
**OF BIG RIVERS ELECTRIC CORPORATION**
**CASE NO. 2014-00166**

**Response to Commission Staff's**
**Initial Request for Information**
**Dated August 20, 2014**

**September 10, 2014**

**Item 4)** **Refer to the partial paragraph at the top of page 21, Section 3, of the IRP, where it states, "Due to the short timeframe since issuance of the order in Case No. 2013-00199 on April 25, 2014, analysis for the preparation of this IRP includes the rates proposed in that case." Explain the effect it would have had on the IRP if the approved rates had been used rather than the proposed rates. Provide a listing of all exhibits that would be changed if the approved rates had been used.**

**Response**) The retail rates granted in Case No. 2013-00199 were lower than proposed. The effect of lower rates is normally reflected in an increase in load forecast, which is a major component of the Integrated Resource Plan. Despite the load forecast being integral to many of the analyses, the impact of the reduced rate is expected to be minimal to the overall analysis of the resources required to meet the anticipated load in this IRP. See the attached listing of exhibits that would be changed if the approved rates had been used.

**Witness)** Marlene S. Parsley

# Big Rivers Electric Corporation
# 2014 Integrated Resource Plan

| Tables and Figures | Would change with an update to reflect 4/25/14 approved rates |
|---|---|
| Table 1.1 | no |
| Figure 1.1 | no |
| Figure 1.2 a, b, c | no |
| Figure 1.3 | no |
| Figure 1.4 | yes |
| Table 1.2 | yes |
| Table 1.3 | yes |
| Figure 1.5 | yes |
| Table 1.4 | yes |
| Table 3.1 | yes |
| Figure 3.1 | yes |
| Table 3.2 | yes |
| Figure 3.2 | yes |
| Table 3.3 | yes |
| Figure 3.3 | yes |
| Table 4.1 | yes |
| Table 4.2 | yes |
| Table 4.3 | yes |
| Table 4.4 | yes |
| Table 4.5 | yes |
| Table 4.6 | yes |
| Table 4.7 | no |
| Table 4.8 | no |
| Table 4.9 | no |
| Table 4.10 | no |
| Table 4.11 | no |
| Table 4.12 | yes |
| Figure 4.1 | no |
| Figure 4.2 | no |
| Figure 4.3 | no |
| Figure 4.4 | yes |
| Table 4.13 | no |
| Table 4.14 | yes |
| Table 4.15 | no |
| Table 4.16 | yes |
| Table 4.17 | yes |
| Table 4.18 | yes |
| Table 4.19 | yes |
| Table 4.20 | yes |
| Table 4.21 | yes |
| Table 4.22 | yes |

| Tables and Figures | Would change with an update to reflect 4/25/14 approved rates |
|---|---|
| Table 5.1 | yes |
| Table 5.2 | yes |
| Table 5.3 | yes |
| Table 5.4 | yes |
| Table 5.5 | yes |
| Table 5.6 | yes |
| Table 5.7 | yes |
| Table 5.8 | yes |
| Table 5.9 | yes |
| Table 5.10 | yes |
| Table 5.11 | yes |
| Table 5.12 | yes |
| Table 5.13 | yes |
| Table 5.14 | no |
| Table 5.15 | yes |
| Table 5.16 | no |
| Table 5.17 | no |
| Table 5.18 | no |
| Table 6.1 | no |
| Table 6.2 | no |
| Figure 7.1 | no |
| Table 7.1 | no |
| Figure 7.2 | no |
| Table 7.2 | no |
| Table 8.1 | no |
| Table 8.2 | no |
| Table 8.3 | no |
| Figure 9.1 | no |
| Table 9.1 | yes |
| Table 9.2 | no |
| Table 9.3 | no |
| Table 9.4 | no |
| Table 9.5 | no |
| Table 9.6 | yes |
| Table 9.7 | no |
| Table 9.8 | yes |
| Table 10.1 | yes |
| Table 10.2 | yes |
| Table 10.3 | yes |
| Table 11.1 | yes |

**BIG RIVERS ELECTRIC CORPORATION**

**2014 INTEGRATED RESOURCE PLAN**
**OF BIG RIVERS ELECTRIC CORPORATION**
**CASE NO. 2014-00166**

**Response to Commission Staff's**
**Initial Request for Information**
**Dated August 20, 2014**

**September 10, 2014**

**Item 5)** **Refer to Section 3.1.1 on page 22 of the IRP, in which changes to Big Rivers' load-forecasting methodology are discussed. Explain why the econometric model developed for the 2013 forecast was used only to develop projections for the years 2013-2017 and not for the entire planning period.**

**Response)** Econometric models were developed to project near term rural system peak demand (monthly for 2013-2017) for Big Rivers' three member distribution cooperatives. Long term rural system peak demand projections (annual for 2018-2027) were based on annual energy sales and average load factor to ensure that peak demand projections increased over the extended forecast horizon at the same rate as total energy requirements.

**Witness)** John W. Hutts

**BIG RIVERS ELECTRIC CORPORATION**

**2014 INTEGRATED RESOURCE PLAN**
**OF BIG RIVERS ELECTRIC CORPORATION**
**CASE NO. 2014-00166**

**Response to Commission Staff's**
**Initial Request for Information**
**Dated August 20, 2014**

**September 10, 2014**

**Item 6) Refer to the third paragraph on page 27 of the IRP, where it states, referring to DSM status reports, that "Big Rivers has filed such reports on January 31, 2012, July 31, 2012, January 31, 2013, July 31, 2013, and January 31, 2014."**

**a. Identify and describe the procedures Big Rivers used to determine the accurate evaluation, measurement, and verification ("EMV") of its programs' results.**

**b. Identify and describe any best practices learned as a result of Big Rivers' EMV processes since the inception of the DSM programs.**

**Response)**

a. The energy savings of each measure is deemed using industry accepted measure savings algorithms and building energy savings models performed by GDS Associates. Each of the Member Cooperatives gathers the appropriate documentation outlined in the applicable tariff and approves the incentive payment. Thus the evaluation is based on deemed savings, and the measurement and verification are performed independently by each of the Member Cooperatives. The Member Cooperatives then send the aggregated measure savings documentation to Big Rivers for participant reimbursement on a monthly basis.

b. Big Rivers and its Member Cooperatives coordinated in the development of the DSM program tariffs, which has proved to be valuable in maintaining administrative and verification consistency. The process of performance evaluation has been simplified by relying on industry accepted methods and sources such as building energy simulation modeling software and energy efficiency technical reference manuals (TRMs). Given the magnitude of the Big Rivers DSM budgets, the EMV costs have been properly managed by relying on deemed savings, secondary sources such as TRMs, and independent verification by the Member Cooperatives.

**Witness)** Russ Pogue

**BIG RIVERS ELECTRIC CORPORATION**

**2014 INTEGRATED RESOURCE PLAN**
**OF BIG RIVERS ELECTRIC CORPORATION**
**CASE NO. 2014-00166**

**Response to Commission Staff's**
**Initial Request for Information**
**Dated August 20, 2014**

**September 10, 2014**

**Item 7) Refer to the fourth paragraph on page 27 of the IRP where it states, "Much of this work is done through a DSM/EE Working Group consisting of Big Rivers' and its Members' employees, which meets monthly."**

**a. Identify the Working Group members and provide their respective responsibilities.**

**b. Explain how Big Rivers coordinates DSM/EE program advertising, promotion, implementation, and monitoring with its member cooperatives.**

**Response)**

a. Each of the Member Cooperative representatives shares experience and expertise with regard to the development, implementation, promotion and administration of their respective programs. The Working Group members are:

| Big Rivers Electric Corporation<br>DSM/EE Working Group Membership | | |
|---|---|---|
| **Name** | **Title** | **Organization** |
| Chuck Williamson | V.P. Finance and Accounting | Jackson Purchase Energy Corporation |
| Izell White | V.P. Human Resources and Member Relations | Jackson Purchase Energy Corporation |
| David Hamilton | V.P. Member Services | Kenergy Corp. |
| Scott Heath | Energy Efficiency Coordinator | Kenergy Corp. |
| David Pace | V.P. Marketing and Member Services | Meade County Rural Electric Cooperative Corporation |
| Russ Pogue | Manager Member Relations | Big Rivers Electric Corporation |

b. Big Rivers and the Member Cooperatives worked together to initially develop programs recommended in the 2010 IRP. Since the initial offerings in 2011, Big Rivers and the Member Cooperatives have worked closely together to institute needed changes in existing programs, develop additional programs and submit tariffs. Member Cooperatives determine the appropriate spend and incentive targets for each program, determine the appropriate methods of program promotion to their rural members and provide budget estimates for various programs.

**Witness)** Russ Pogue

**BIG RIVERS ELECTRIC CORPORATION**

**2014 INTEGRATED RESOURCE PLAN**
**OF BIG RIVERS ELECTRIC CORPORATION**
**CASE NO. 2014-00166**

**Response to Commission Staff's**
**Initial Request for Information**
**Dated August 20, 2014**

**September 10, 2014**

**Item 8)** **Refer to Tables 3.1, 3.2, 3.3, 4.1, 4.2, and to page 29, Section 4, of the IRP. Section 4, having been completed in 2013, indicates that the most recent historical year in the forecast is 2012. Provide revised versions of the tables which include the actual and, as appropriate, weather-adjusted results for 2013.**

**Response)** Please see attachment.

**Witness)** Marlene S. Parsley

Native System Table 3.2
Energy Requirements

| | Actual | Weather Adjusted | 2010 IRP | 2011 Load Forecast | 2013 Load Forecast |
|---|---|---|---|---|---|
| 2002 | 3,233 | 3,174 | | | |
| 2003 | 3,088 | 3,148 | | | |
| 2004 | 3,159 | 3,219 | | | |
| 2005 | 3,260 | 3,251 | | | |
| 2006 | 3,214 | 3,281 | | | |
| 2007 | 3,353 | 3,288 | | | |
| 2008 | 3,340 | 3,323 | | | |
| 2009 | 3,231 | 3,277 | 3,371 | | |
| 2010 | 3,474 | 3,346 | 3,403 | | |
| 2011 | 3,377 | 3,369 | 3,437 | 3,355 | |
| 2012 | 3,320 | 3,320 | 3,472 | 3,366 | |
| 2013 | 3,452 | 3,435 | 3,503 | 3,398 | 3,346 |
| 2014 | | | 3,539 | 3,438 | 3,400 |
| 2015 | | | 3,579 | 3,469 | 3,373 |
| 2016 | | | 3,619 | 3,509 | 3,358 |
| 2017 | | | 3,666 | 3,547 | 3,375 |
| 2018 | | | 3,712 | 3,574 | 3,393 |
| 2019 | | | 3,758 | 3,602 | 3,412 |
| 2020 | | | 3,799 | 3,637 | 3,432 |
| 2021 | | | 3,846 | 3,672 | 3,453 |
| 2022 | | | 3,892 | 3,709 | 3,476 |
| 2023 | | | 3,936 | 3,746 | 3,499 |
| 2024 | | | | 3,785 | 3,523 |
| 2025 | | | | 3,823 | 3,547 |
| 2026 | | | | | 3,571 |
| 2027 | | | | | 3,597 |
| 2028 | | | | | 3,623 |

Table 3.3
Peak Demand

| Actual | Weather Adjusted | 2010 IRP | 2011 Load Forecast | 2013 Load Forecast |
|---|---|---|---|---|
| 595 | | | | |
| 578 | | | | |
| 599 | 632 | | | |
| 613 | 618 | | | |
| 626 | 647 | | | |
| 654 | 625 | | | |
| 614 | 629 | | | |
| 668 | 642 | 637 | | |
| 657 | 645 | 641 | | |
| 652 | 650 | 648 | 648 | |
| 654 | 630 | 655 | 650 | |
| 609 | 619 | 661 | 656 | 632 |
| | | 668 | 664 | 635 |
| | | 676 | 671 | 635 |
| | | 684 | 679 | 637 |
| | | 693 | 686 | 642 |
| | | 702 | 692 | 645 |
| | | 711 | 698 | 649 |
| | | 719 | 705 | 653 |
| | | 728 | 712 | 658 |
| | | 737 | 719 | 663 |
| | | 746 | 727 | 668 |
| | | | 735 | 673 |
| | | | 743 | 678 |
| | | | | 683 |
| | | | | 688 |
| | | | | 694 |

Table 3.1

Customers

| | *Actual* | *2010 IRP* | *2011 Load Forecast* | *2013 Load Forecast* |
|---|---|---|---|---|
| *2002* | *103,482* | | | |
| *2003* | *104,764* | | | |
| *2004* | *106,414* | | | |
| *2005* | *107,883* | | | |
| *2006* | *109,329* | | | |
| *2007* | *110,585* | | | |
| *2008* | *111,693* | | | |
| *2009* | *111,923* | *112,492* | | |
| *2010* | *112,391* | *113,497* | | |
| *2011* | *112,888* | *114,870* | *112,972* | |
| *2012* | *113,252* | *116,410* | *113,995* | |
| *2013* | *113,720* | *117,975* | *115,512* | *113,584* |
| *2014* | | *119,519* | *117,033* | *114,565* |
| *2015* | | *121,046* | *118,522* | *115,678* |
| *2016* | | *122,559* | *119,872* | *116,773* |
| *2017* | | *124,064* | *121,078* | *117,835* |
| *2018* | | *125,574* | *122,226* | *118,838* |
| *2019* | | *127,088* | *123,348* | *119,816* |
| *2020* | | *128,596* | *124,448* | *120,804* |
| *2021* | | *130,081* | *125,515* | *121,792* |
| *2022* | | *131,521* | *126,539* | *122,754* |
| *2023* | | *132,906* | *127,522* | *123,698* |
| *2024* | | | *128,468* | *124,602* |
| *2025* | | | *129,384* | *125,493* |
| *2026* | | | | *126,386* |
| *2027* | | | | *127,264* |
| *2028* | | | | *128,156* |

*Total System Detail* *Table 4.1*

| | Member Coop Retail Sales (MWH) | Distribution Losses (%) | Big Rivers Energy Sales (MWH) | Replacement Load (MWH) | G&T Losses (MWH) | HMP&L (MWH) | Total Energy Requirements (MWH) |
|---|---|---|---|---|---|---|---|
| 2009 | 3,092,391 | 3.5% | 3,206,088 | | 109,411 | 591,442 | 3,906,942 |
| 2010 | 3,317,423 | 3.7% | 3,445,715 | | 117,589 | 646,412 | 4,209,716 |
| 2011 | 3,279,929 | 3.1% | 3,385,501 | | 115,534 | 622,398 | 4,123,434 |
| 2012 | 3,367,558 | 3.5% | 3,488,924 | | 119,064 | 618,841 | 4,226,829 |
| 2013 | 3,437,981 | 2.9% | 3,539,995 | | 86,306 | 616,909 | 4,243,210 |
| 2014 | 3,186,016 | 3.4% | 3,299,668 | | 108,376 | 628,649 | 4,036,693 |
| 2015 | 3,160,648 | 3.4% | 3,272,777 | | 110,987 | 630,721 | 4,014,486 |
| 2016 | 3,150,370 | 3.4% | 3,261,996 | 658,800 | 132,963 | 632,755 | 4,686,514 |
| 2017 | 3,169,657 | 3.4% | 3,282,401 | 1,314,000 | 155,875 | 634,785 | 5,387,061 |
| 2018 | 3,188,948 | 3.5% | 3,303,481 | 1,971,000 | 178,870 | 636,785 | 6,090,136 |
| 2019 | 3,212,937 | 3.4% | 3,324,408 | 2,628,000 | 201,860 | 638,767 | 6,793,034 |
| 2020 | 3,233,625 | 3.4% | 3,346,664 | 3,952,800 | 247,542 | 640,733 | 8,187,739 |
| 2021 | 3,253,637 | 3.5% | 3,370,638 | 5,256,000 | 292,549 | 642,685 | 9,561,873 |
| 2022 | 3,276,566 | 3.5% | 3,395,606 | 5,256,000 | 293,396 | 644,607 | 9,589,609 |
| 2023 | 3,304,256 | 3.4% | 3,420,514 | 5,256,000 | 294,241 | 646,527 | 9,617,281 |
| 2024 | 3,327,438 | 3.4% | 3,445,403 | 5,270,400 | 295,573 | 648,414 | 9,659,790 |
| 2025 | 3,349,159 | 3.5% | 3,471,146 | 5,256,000 | 295,958 | 650,294 | 9,673,398 |
| 2026 | 3,373,531 | 3.5% | 3,497,557 | 5,256,000 | 296,853 | 652,174 | 9,702,585 |
| 2027 | 3,403,140 | 3.4% | 3,524,436 | 5,256,000 | 297,765 | 654,054 | 9,732,255 |
| 2028 | 3,432,749 | 3.4% | 3,552,719 | 5,270,400 | 299,212 | 655,935 | 9,778,266 |

***Shaded year represents base year***

***Transmission losses adjusted in 2009 -2013 to reflect the exclusion of smelter load impacts***

***HMP&L based on HMP&L load forecast***

***Values are net of DSM***

*Control Area Peak Demand* *Table 4.2*

| | Rural System (MW) | Direct Serve (MW) | Native System (MW) | Replacement Load (MW) | G&T Losses (MWH) | HMP&L (MW) | Total Peak Demand (MW) |
|---|---|---|---|---|---|---|---|
| 2009 | 561 | 107 | 668 | | 23 | 111 | 801 |
| 2010 | 540 | 117 | 657 | | 22 | 117 | 797 |
| 2011 | 533 | 119 | 652 | | 22 | 113 | 787 |
| 2012 | 542 | 89 | 630 | | 22 | 115 | 767 |
| 2013 | 472 | 136 | 609 | | 15 | 108 | 732 |
| 2014 | 511 | 126 | 637 | | 21 | 117 | 775 |
| 2015 | 512 | 126 | 638 | | 22 | 118 | 777 |
| 2016 | 516 | 125 | 641 | 100 | 25 | 118 | 884 |
| 2017 | 522 | 125 | 647 | 200 | 29 | 118 | 994 |
| 2018 | 526 | 125 | 651 | 300 | 32 | 119 | 1,102 |
| 2019 | 531 | 125 | 656 | 400 | 36 | 119 | 1,211 |
| 2020 | 536 | 125 | 661 | 600 | 43 | 120 | 1,423 |
| 2021 | 541 | 125 | 666 | 800 | 50 | 120 | 1,636 |
| 2022 | 547 | 125 | 672 | 800 | 50 | 120 | 1,642 |
| 2023 | 552 | 125 | 678 | 800 | 50 | 121 | 1,649 |
| 2024 | 558 | 125 | 683 | 800 | 50 | 121 | 1,655 |
| 2025 | 564 | 125 | 689 | 800 | 51 | 121 | 1,661 |
| 2026 | 570 | 125 | 695 | 800 | 51 | 122 | 1,668 |
| 2027 | 576 | 125 | 702 | 800 | 51 | 122 | 1,674 |
| 2028 | 583 | 125 | 708 | 800 | 51 | 122 | 1,682 |

***Shaded year represents base year***

***Transmission losses adjusted in 2009 -2013 to reflect the exclusion of smelter load impacts***

***HMP&L based on HMP&L load forecast***

***Values are net of DSM***

**BIG RIVERS ELECTRIC CORPORATION**

**2014 INTEGRATED RESOURCE PLAN**
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**Item 9)** **Refer to the second paragraph in Section 4.1 on page 29 of the IRP. Explain in detail of how Big Rivers determined that replacement load is expected to increase by approximately 800 percent between 2016 and 2021.**

**Response)** As a result of the smelter termination notices received in August 2012 and January 2013, Big Rivers had 850MW of generation available for sale. After considering future reserve margins, Big Rivers' management and Board determined it was in the organization's best interest to replace only 800MW of load to delay any potential future need for additional generation.

After Big Rivers determined it would replace 800MW it was agreed, through numerous internal discussions among senior staff, that it would take a number of years to secure replacement contracts. The power market was projected to begin increasing in 2016. Thus, management believed the start of replacement load would occur at that point in time. Management wanted to be realistic, but conservative, in its expectation for replacement timing, thus decided on the replacement schedule included in the load forecast.

**Witness)** Lindsay N. Barron

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**Item 10)** **Refer to Section 4.2.1 of the IRP, page 34, Table 4.5. Explain the reason for the difference in the change in the number of customers from 2013 to 2014 compared with the change in number of customers from 2012 to 2013. Include in the response the actual number of residential customers for calendar year 2013.**

**Response)** The number of customers grew modestly by .2% from 2012 to 2013 and by .9% from 2013 to 2014. Residential customer growth was very low during the recession and national recovery. Growth is projected to rebound as the economy returns to pre-recession levels and housing starts increase. The number of residential customers served by Big Rivers' three Members for 2013 is 97,773.

**Witness)** Marlene S. Parsley

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**Item 11)** **Refer to Table 4.7 on page 36 of the IRP. The discussion immediately preceding the table, in Section 4.2.3, states that large commercial and industrial sales are projected to be essentially flat during the forecast period.**

**a. Explain what accounts for the growth in sales projected in the table for the years 2014 and 2015.**

**b. Provide a revised version of Table 4.7 which includes 2013 results.**

**Response)**

a. The growth in sales projected in the table for the years 2014 and 2015 was driven by expected growth in the load of Pennyrile Energy, LLC.

b. Please see the attached table.

**Witness)** Marlene Parsley

Table 4.7
Large Commercial & Industrial

| | Number of Customers | Change per Yr. | % Change per Yr. | Energy Sales (MWH) | % Change per Yr. | Avg. kWh per Mo. Per Customer | % Change per Yr. |
|---|---|---|---|---|---|---|---|
| 2009 | 17 | | | 932,868 | | 4,572,882 | |
| 2010 | 17 | 0 | 0.0% | 966,126 | 3.6% | 4,735,912 | 3.6% |
| 2011 | 19 | 2 | 11.8% | 974,046 | 0.8% | 4,272,130 | -9.8% |
| 2012 | 19 | 0 | 0.0% | 962,599 | -1.2% | 4,221,926 | -1.2% |
| 2013 | 21 | 2 | 10.5% | 996,267 | 3.5% | 3,953,442 | -6.4% |
| 2014 | 20 | (1) | -4.8% | 981,796 | -1.5% | 4,090,818 | 3.5% |
| 2015 | 20 | 0 | 0.0% | 985,814 | 0.4% | 4,107,558 | 0.4% |
| 2016 | 20 | 0 | 0.0% | 985,325 | 0.0% | 4,105,521 | 0.0% |
| 2017 | 20 | 0 | 0.0% | 982,555 | -0.3% | 4,093,980 | -0.3% |
| 2018 | 20 | 0 | 0.0% | 982,555 | 0.0% | 4,093,980 | 0.0% |
| 2019 | 20 | 0 | 0.0% | 982,555 | 0.0% | 4,093,980 | 0.0% |
| 2020 | 20 | 0 | 0.0% | 982,555 | 0.0% | 4,093,980 | 0.0% |
| 2021 | 20 | 0 | 0.0% | 982,555 | 0.0% | 4,093,980 | 0.0% |
| 2022 | 20 | 0 | 0.0% | 982,555 | 0.0% | 4,093,980 | 0.0% |
| 2023 | 20 | 0 | 0.0% | 982,555 | 0.0% | 4,093,980 | 0.0% |
| 2024 | 20 | 0 | 0.0% | 982,555 | 0.0% | 4,093,980 | 0.0% |
| 2025 | 20 | 0 | 0.0% | 982,555 | 0.0% | 4,093,980 | 0.0% |
| 2026 | 20 | 0 | 0.0% | 982,555 | 0.0% | 4,093,980 | 0.0% |
| 2027 | 20 | 0 | 0.0% | 982,555 | 0.0% | 4,093,980 | 0.0% |
| 2028 | 20 | 0 | 0.0% | 982,555 | 0.0% | 4,093,980 | 0.0% |

***Number of customers and energy sales for all years exclude aluminum smelters***

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**Item 12)** **Refer to Section 4.2.6 of the IRP, page 39, which references an economic development incentive rate proposed by Big Rivers. Provide the rate and state whether it has been approved by the Commission.**

**Response)** Big Rivers has a proposed economic development incentive rate ("EDR") which it is offering to its Members in an effort to attract new load to western Kentucky. Big Rivers' EDR has not yet been submitted to or approved by the Commission. When Big Rivers and its Members are successful in attracting new load, Big Rivers plans to seek Commission approval of the EDR through the submission of a special contract pursuant to the Commission's order issued on September 24, 1990 in Administrative Case No. 327.

The EDR is currently offered to new or expansion load above 1,000 kW billing demand which is engaged in manufacturing (or similar). New or expansion load in excess of 1,000kW will incur a demand rate equal to 10% of Big Rivers' LIC Tariff Demand Rate, before application of other adjustments. Energy will be charged pursuant to Big Rivers' LIC Tariff and all additional riders and charges will apply. The term for the discount period will not exceed four (4) years with a minimum EDR contract term twice the term of the discount period.

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**Witness)** Lindsay N. Barron

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**Item 13)** **Refer to Section 4.3, the sentence beginning at the bottom of page 40 and continuing to the top of page 41. It reads, "As measured by degree days, 2010 was the hottest year in over 20 years, and 2010 was the coldest year since 1997." Confirm that both references in the sentence are intended to be to calendar year 2010.**

**Response)** Confirmed. Both references in the sentence at the bottom of page 40 and continuing to the top of page 41 refer to calendar year 2010. Heating and cooling degree days are commonly used for estimating energy required for heating and cooling. Heating degree days are computed on a daily basis and summed to the monthly and annual totals. Heating degree days are computed as the greater of (1) a base temperature of 65 degrees less the average daily temperature, or (2) zero. Similarly, cooling degree days are computed as the greater of (1) average daily temperature less a base temperature of 65 degrees, or (2) zero. Calendar year 2010 was unusual in that the number of heating degree days was the highest since 1997, and the number of cooling degree days was the highest since before 1993.

**Witness)** John W. Hutts

**BIG RIVERS ELECTRIC CORPORATION**

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**Item 14) Refer to Section 4.6.3 on page 49 of the IRP, specifically, the paragraph which indicates that Big Rivers uses the most recent 20-year averages of heating and cooling degree days. Footnote 41 on page 47 identifies the National Oceanic and Atmospheric Administration ("NOAA") as the source of the degree day data.**

**a. State when Big Rivers began using NOAA data and for how long it has used a 20-year average of heating and cooling degree days.**

**b. Explain why Big Rivers uses 20-year averages and describe what consideration, if any, it has given to using averages for a period other than 20 years.**

**Response)**

a. All load forecasts prepared by Big Rivers since at least 1993 have incorporated weather data sourced to NOAA. Big Rivers has used a 20-year average of heating and cooling degree days in preparing load forecasts since development of the 2001 Load Forecast.

b. Big Rivers uses a 20-year average for representing the average of historical heating and cooling degree days because 20 years is a stable period (rolling 20-year averages do not show significant fluctuations from year to year). No consideration has been given to changing the normal period to more or fewer years.

**Witness)** John W. Hutts

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**Item 15)** **Refer to the discussion of retail electricity prices on page 50 of the IRP, which states that the average price to rural system customers was expected to increase 39 percent in real terms by 2016. Given that Big Rivers was awarded less than the amounts requested in the two rate cases it filed in response to the smelter contract terminations, provide the percentage increase, in real terms, it now expects by 2016.**

**Response)** Based on the lesser amount awarded in the two rates cases Big Rivers filed in response to the smelter contract terminations, the percentage increase it now expects for rural system customers is 26%.

**Witness)** Christopher A. Warren

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**Item 16) Refer to the first full paragraph on page 53 of the IRP, which indicates that the t-statistic for the average household income parameter in the model for Kenergy Corp. ("Kenergy") is significant at the "0.05 alpha, 95% confidence level," while it is not significant at the same level for Big Rivers' two other member cooperatives. While there is discussion of the lack of significance of average household income for those two cooperatives, there is no discussion of its significance for Kenergy.**

**a. Based on the discussion on the lack of significance of average household income for two of Big Rivers' cooperatives, explain generally whether its significance in the case of Kenergy indicates a greater correlation between income and energy consumption in its service area.**

**b. Explain whether there are obvious reasons or circumstances why average household income's impact is not more consistent across the service areas of all three member cooperatives.**

**Response)**

a. In the case of the models developed for the three Member distribution cooperatives, the higher significance of the household income variable in the Kenergy model indicates a greater correlation between household income and energy consumption.

b. There are no obvious reasons why the impact of household income is not consistent across the three service territories; however, the most probable is class composition. While the majority of accounts in the residential class for each cooperative represent dwellings, there are a number of non-dwelling type accounts served by each cooperative that are classified as residential (barns, workshops, fences, pumps, wells, security lights, etc.). While Big Rivers has not conducted research on non-dwelling accounts, it is assumed that average consumption for non-dwelling accounts is lower than average home consumption and is not impacted by income to the extent of typical home consumption. Given the higher magnitude of average consumption for Kenergy relative to the other two coops, Kenergy's residential class may include fewer low-use non-dwelling accounts, which would lead to the assumption of higher average kWh use than for a cooperative with a greater proportion of non-dwelling type accounts. Additionally, the JPEC and MCRECC service areas are believed to have more vacation and seasonal homes than Kenergy. While Big Rivers has not conducted research on vacation and seasonal homes with respect to income, average consumption for these type homes is lower than for year round homes, which could have a negative impact on the correlation between income and consumption for the entire class.

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2 **Witness)** John W. Hutts

**BIG RIVERS ELECTRIC CORPORATION**

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**Item 17) Refer to Tables 4.17 and 4.18 on page 55 of the IRP, which compare energy requirements and peak demands under the base, pessimistic, and optimistic economy scenarios. Table 4.17 reflects total requirements, while Table 4.18 reflects the rural system.**

**a. The relative differences between the optimistic and base economy scenarios in Table 4.18 for years 2023 and 2028 vary much more than in Table 4.17. Confirm that the optimistic economy scenario results for those years are correct.**

**b. If the response to part a. of this request is affirmative, explain why the relationship between the base and optimistic results is so much different than the relationship between the base and pessimistic results for 2023 and 2028 in Table 4.17.**

**Response)**

a. The values presented in Tables 4.17 and 4.18 are correct.

b. The relative differences between the base and optimistic scenarios in Tables 4.17 and 4.18 are explained by the assumptions regarding replacement load (refer to section 4.2.4 of the IRP). Specifically, replacement sales are included in the base case scenario in Table 4.17 and in the optimistic scenario in Table 4.18.

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In Table 4.17, total energy requirements for the base case included all replacement load in a separate category without assigning it to a specific customer class or type. The optimistic scenario does not reflect an assumption that replacement sales will be higher than replacement sales in the base case; therefore, the differences between the base case and optimistic case in Table 4.17 reflect only the impacts on native load associated with optimistic economic conditions.

In Table 4.18, rural system energy requirements in the optimistic scenario are based on the assumption that all replacement sales will be entirely native system load split between the rural system and direct serve classifications. In Table 4.18, the optimistic scenario reflects not only the impacts of optimistic economic conditions on existing load, but also the assumption that a portion of replacement sales will be rural system load growth.

**Witness)** John W. Hutts

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**Item 18)** **Refer to Section 5.1, the last bullet point on page 59 of the IRP where it states, "At the direction of Big Rivers' staff, GDS also produced a sensitivity of potential savings at an incentive budget of $2 million." Identify the circumstances in which Big Rivers would implement the incentive budget of $2 million.**

**Response)** Big Rivers is currently authorized to collect $1 million in base rates and has not yet determined if a change in program level spending is appropriate. We continue to work with our Members to determine the optimum spending level for our Members.

**Witness)** Russ Pogue

**BIG RIVERS ELECTRIC CORPORATION**

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**Item 19)** **Refer to Table 5.2 on page 60 of the IRP. Provide in electronic format, with cells unprotected, spreadsheets showing the information used in developing the net present value of benefits and costs in the table for the Program ($1 million) scenario.**

**Response)** The spreadsheet files used to develop the net present value of benefits and costs are provided on the confidential electronic media accompanying these responses. There are two files. One addresses the residential sector. The other addresses the non-residential sector.

**Witness)** Russ Pogue

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**Item 20) Refer to the bottom of page 60 of the IRP where nine EE programs Big Rivers plans to continue funding as part of its DSM portfolio are listed. Also refer to Table 5.15 on page 70, which shows 2013 DSM/EE program results and which shows 12 programs is 2013.**

**a. Identify the programs Big Rivers does not plan to continue funding and explain how it proposes to address any changes to the program(s).**

**b. Explain whether Big Rivers has the Table 5-15 information broken down by member cooperative. If it does, provide the information for each cooperative.**

**Response)**

a. Big Rivers does not have plans to discontinue any programs. The analysis summary on page 60 combines some measures that are broken out in more detail for the program tariffs listed on page 70. In the description of the Residential Efficient Appliance Program on page 62 it states, "The programs promote installation of clothes washers and refrigerators and the removal and recycling of older inefficient refrigerators". On page 70, DSM-02 Energy Star Clothes Washer Replacement and DSM-03 Energy Star Refrigerator Replacement are listed as two tariffed programs. The Commercial and Industrial Prescriptive Lighting Program analysis includes both

DSM-08 C&I High Efficiency Lighting and DSM-12 High Efficiency Outdoor Lighting. The Commercial and Industrial Prescriptive HVAC Program analysis includes both DSM -07 C&I HVAC Tune-Up and DSM-11 High Efficiency HVAC tariffs.

b. Yes, please see attached documents.

**Witness)** Russ Pogue

# Big Rivers Electric Corporation
# 2014 Integrated Resource Plan

**Jackson Purchase Energy**

| | | 2013 Program Totals | |
|---|---|---|---|
| **Residential Programs** | **Units** | **Unit Quantity** | **Spend** |
| DSM-01 High Efficiency Lighting Replacement | bulbs | 18,794 | $32,515 |
| DSM-02 Energy Star Clothes Washer Replacement | unit | 135 | $13,500 |
| DSM-03 Energy Star Refrigerator Replacement | unit | 52 | $5,200 |
| DSM-04 Residential High Efficiency HVAC | unit | 48 | $17,500 |
| DSM-05/DSM-10 Residential Weatherization | homes | 6 | $19,217 |
| DSM-06 Touchstone Energy New Home | homes | 2 | $4,000 |
| DSM-07 Residential HVAC Tune-Up | unit | 92 | $2,300 |
| **Commercial/Industrial (C/I) Programs** | | | |
| DSM-08 C/I High Efficiency Lighting | kW saved | 7 | $2,561 |
| DSM-09 C/I General Energy Efficiency | kW saved | 0 | $0 |
| DSM-07 C/I HVAC Tune-Up | units | 8 | $400 |
| DSM-11 C/I High Efficiency HVAC | ton | 0 | $0 |
| **Other** | | | |
| DSM-12 High Efficiency Outdoor Lighting | fixture | 0 | $0 |
| Promotion Expense | | | $210 |
| Total | | | $97,403 |

# Big Rivers Electric Corporation
# 2014 Integrated Resource Plan

**Kenergy Corp**

| | | 2013 Program Totals | |
|---|---|---|---|
| **Residential Programs** | **Units** | **Unit Quantity** | **Spend** |
| DSM-01 High Efficiency Lighting Replacement | bulbs | 37,500 | $64,872 |
| DSM-02 Energy Star Clothes Washer Replacement | unit | 665 | $66,500 |
| DSM-03 Energy Star Refrigerator Replacement | unit | 460 | $46,000 |
| DSM-04 Residential High Efficiency HVAC | unit | 135 | $49,900 |
| DSM-05/DSM-10 Residential Weatherization | homes | 71 | $227,400 |
| DSM-06 Touchstone Energy New Home | homes | 77 | $64,600 |
| DSM-07 Residential HVAC Tune-Up | unit | 413 | $10,325 |
| **Commercial/Industrial (C/I) Programs** | | | |
| DSM-08 C/I High Efficiency Lighting | kW saved | 431 | $150,896 |
| DSM-09 C/I General Energy Efficiency | kW saved | 0 | $0 |
| DSM-07 C/I HVAC Tune-Up | units | 97 | $4,850 |
| DSM-11 C/I High Efficiency HVAC | ton | 0 | $0 |
| **Other** | | | |
| DSM-12 High Efficiency Outdoor Lighting | fixture | 262 | $18,340 |
| Promotion Expense | | | $61,412 |
| Total | | | $765,095 |

# Big Rivers Electric Corporation
# 2014 Integrated Resource Plan

**Meade County RECC**

| | | 2013 Program Totals | |
|---|---|---|---|
| **Residential Programs** | **Units** | **Unit Quantity** | **Spend** |
| DSM-01 High Efficiency Lighting Replacement | bulbs | 18,780 | $32,490 |
| DSM-02 Energy Star Clothes Washer Replacement | unit | 261 | $26,100 |
| DSM-03 Energy Star Refrigerator Replacement | unit | 162 | $16,200 |
| DSM-04 Residential High Efficiency HVAC | unit | 79 | $25,450 |
| DSM-05/DSM-10 Residential Weatherization | homes | 91 | $291,455 |
| DSM-06 Touchstone Energy New Home | homes | 4 | $6,000 |
| DSM-07 Residential HVAC Tune-Up | unit | 51 | $1,275 |
| **Commercial/Industrial (C/I) Programs** | | | |
| DSM-08 C/I High Efficiency Lighting | kW saved | 145 | $50,617 |
| DSM-09 C/I General Energy Efficiency | kW saved | 0 | $0 |
| DSM-07 C/I HVAC Tune-Up | units | 13 | $650 |
| DSM-11 C/I High Efficiency HVAC | ton | 0 | $0 |
| **Other** | | | |
| DSM-12 High Efficiency Outdoor Lighting | fixture | 0 | $0 |
| Promotion Expense | | | $40,045 |
| Total | | | $490,282 |

**BIG RIVERS ELECTRIC CORPORATION**

**2014 INTEGRATED RESOURCE PLAN**
**OF BIG RIVERS ELECTRIC CORPORATION**
**CASE NO. 2014-00166**

**Response to Commission Staff's**
**Initial Request for Information**
**Dated August 20, 2014**

**September 10, 2014**

**Item 21)** **Refer to page 73 of the IRP, Table 5.17. Under the Commercial/Industrial Programs section, some of the cells contain "#REF!" Provide a corrected Table 5.17.**

**Response)** Please see the attached table.

**Witness)** Russ Pogue

# Big Rivers 2012 DSM/Energy Efficiency Program Impact

| Residential Programs | Annual kWh Savings Per Unit | Winter kW Savings Per Unit | Summer kW Savings Per Unit | Unit Quantity | Total Annual kWh Savings | Total Winter kW Savings | Total Summer kW Savings |
|---|---|---|---|---|---|---|---|
| Residential Lighting Program | | | | | | | |
| CFL bulbs | 31 | 0.007 | 0.003 | 51,792 | 1,587,943 | 369.8 | 162.4 |
| Residential Efficient Appliances | | | | | | | |
| Clothes Washer Rebate | 224 | 0.007 | 0.026 | 563 | 126,112 | 3.9 | 14.6 |
| Energy Star Refrigerator + Recycling | 1,084 | 0.076 | 0.089 | 383 | 415,172 | 29.1 | 34.1 |
| HVAC Program | | | | | | | |
| Dual Fuel | 3,448 | 7.066 | 0.146 | 33 | 113,784 | 233.2 | 4.8 |
| Air Source Heat Pump | 692 | 0.000 | 0.146 | 46 | 31,832 | 0.0 | 6.7 |
| Goethermal | 3,658 | 4.453 | 0.365 | 21 | 76,818 | 93.5 | 7.7 |
| Weatherization Program | | | | | | | |
| Stick-Built Home | 6,980 | 4.950 | 0.890 | 9 | 62,820 | 44.6 | 8.0 |
| Manufactured Home | 4,680 | 2.200 | 0.300 | 1 | 4,680 | 2.2 | 0.3 |
| New Construction | | | | | | | |
| Gas Heat | 2,435 | 0.260 | 0.580 | 67 | 163,145 | 17.4 | 38.9 |
| Air Source Heat Pump | 4,922 | 2.700 | 0.580 | 2 | 9,843 | 5.4 | 1.2 |
| Dual Fuel Heat Pump (w/ Gas) | 8,370 | 9.766 | 0.580 | 0 | 0 | 0.0 | 0.0 |
| Geothermal Heat Pump | 8,580 | 7.150 | 0.799 | 2 | 17,159 | 14.3 | 1.6 |
| Tune-Up | | | | | | | |
| HVAC Tune-Up | 636 | 0.000 | 0.304 | 260 | 165,360 | 0.0 | 79.0 |

| Commercial/Industrial (C/I) Programs | Annual kWh Savings Per $ | Winter kW Savings Per $ | Summer kW Savings Per $ | Total kW Reduced | Total Annual kWh Savings | Total Winter kW Savings | Total Summer kW Savings |
|---|---|---|---|---|---|---|---|
| C&I Lighting | | | | | | | |
| Lighting Projects | 12 | 0.0028 | 0.0027 | 418 | 1,710,419 | 418.4 | 390.9 |
| C&I Products | | | | | | | |
| Misc. Efficient Projects | 8 | 0.0006 | 0.0032 | 31 | 76,446 | 5.8 | 30.8 |

| | Annual kWh Savings Per Unit | Winter kW Savings Per Unit | Summer kW Savings Per Unit | Unit Quantity | Total Annual kWh Savings | Total Winter kW Savings | Total Summer kW Savings |
|---|---|---|---|---|---|---|---|
| Tune-Up | | | | | | | |
| HVAC Tune-Up* | 5,268 | 0.000 | 1.200 | 77 | 405,636 | 0.0 | 92.4 |
| ** Assumed 6 tons/unit* | | | | | | | |
| | | | | Total DSM Program Savings: | 4,967,169 | 1,237.6 | 873.3 |

**Case No. 2014-00166**
**Attachment for Response to PSC 1-21**
**Witness: Russ Pogue**

**BIG RIVERS ELECTRIC CORPORATION**

**2014 INTEGRATED RESOURCE PLAN**
**OF BIG RIVERS ELECTRIC CORPORATION**
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**September 10, 2014**

**Item 22)** **Refer to Section 8.7 of the IRP, page 92, and page 98, Table 9.3. The last paragraph on page 92 states, "Big Rivers plans to evaluate the conversion of a portion of its existing coal-fired fleet to natural gas as an alternative to installing additional pollution control equipment at its Green and Coleman facilities." Table 9.3 shows natural gas as the secondary fuel type for the Coleman Station. Describe the work that would have to be done to convert the Coleman Station to natural gas.**

**Response)** In Table 9.3, the secondary fuel type listed is for the start-up fuel. Coleman Station utilizes natural gas for its start-up fuel and is not currently capable of obtaining the unit rated capacity burning natural gas instead of coal.

Much work would have to be done to convert Coleman Station to natural gas. An engineering firm would most likely be hired to study, determine and design the best option for a fuel switch to natural gas. Generally speaking, the availability of an appropriate gas supply would need to be determined, and if one is not available, the cost of providing an appropriate gas supply. Next, the technical considerations like burner modifications, impacts on boiler design and capacity, changes to fans, ductwork, fluework and other equipment design issues will be evaluated. Finally, the environmental impacts and financial considerations will be evaluated, and a new Title V permit would be required.

**BIG RIVERS ELECTRIC CORPORATION**

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**CASE NO. 2014-00166**

**Response to Commission Staff's**
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**Dated August 20, 2014**

**September 10, 2014**

1

2 **Witness)** Duane E. Braunecker

**BIG RIVERS ELECTRIC CORPORATION**

**2014 INTEGRATED RESOURCE PLAN**
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**September 10, 2014**

**Item 23) Refer to the first full paragraph on page 102 of the IRP where it states that administrative costs were assumed to equal 20 percent of the incremental cost of measures. Also refer to Big Rivers' response to Item 10 of Commission Staff's First Information Request ("Staff's First Request") in Case No. 2010-00443.[11]**

**a. Explain how Big Rivers arrived at 20 percent for the assumed level of administrative costs as a percentage of incremental cost of measures.**

**b. Explain whether the 20 percent assumption is consistent with the response to the Staff's First Request, which indicated that administrative costs varied greatly among different types of programs.**

**Response)**

a. The level of assumed administrative costs as a percentage of incremental costs is based upon Table B-4.1 in Appendix B-4 of the report titled, "Assessment of Long-Term System-Wide Potential for Demand-Side and Other Supplemental Resource, 2013-2032," which was prepared for PacifiCorp in March 2013. The main report and the appendices are provided on the electronic media accompanying these responses.

[1] Case No. 2010-00443, 2010 Integrated Resource Plan of Big Rivers Electric Corporation (Ky. PSC Dec. 21, 2011).

This level of assumed administrative costs represents the average administrative costs as a percentage of incremental measure costs across seven utilities in 2010 and 2011.

b. The 20 percent is not consistent with the response to the Staff's First Request. While, the 20 percent is closely aligned with the administrative costs that were assumed in Case No. 2010-00443, the 20 percent assumption is based on more current data using actual program performance across seven utilities, which is appropriate for estimating administrative costs across the portfolio of programs in the IRP.

**Witness)** Russ Pogue

**BIG RIVERS ELECTRIC CORPORATION**

**2014 INTEGRATED RESOURCE PLAN**
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**CASE NO. 2014-00166**

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**September 10, 2014**

**Item 24)** **Refer to Section 9.1 on page 94 of the IRP, where Big Rivers discusses generation maintenance. Provide the current schedule for maintenance of Big Rivers' generators, and indicate the extent to which Big Rivers has adhered to the schedule for each generator.**

**Response)** The referenced section of the IRP (Section 9.1, page 94) where generation maintenance is discussed refers to Big Rivers' continued focus on generation efficiency by performing maintenance tasks such as washing air heaters, cleaning condenser tubes, replace leaking valves and repairing gas leaks during all opportunities when the unit is off line.

Please see the confidential attachment displaying the current planned maintenance schedule for the Big Rivers' generators for the five year period (2014 – 2018). Big Rivers deferred planned maintenance in the past in order to meet its financial obligations. Big Rivers has now completed the planned maintenance on its running units that was deferred and is now back on its normal planned maintenance schedule. Without any unforeseen circumstances and with the rates currently in place, Big Rivers will be able to adhere to the current maintenance schedule.

**Witness)** James Garrett

# Big Rivers Planned Outages (2014 -2018)

| Start | End | Hours | Days | Unit | Status |
|---|---|---|---|---|---|
| 4/26/2014 0:00 | 5/17/2014 0:00 | 504 | 21 | HMPL 1 | Completed |
| 5/10/2014 0:00 | 6/21/2014 0:00 | 1008 | 42 | Wilson | Completed |
| 7/15/2014 0:00 | 7/24/2014 0:00 | 216 | 9 | Green 1 | Completed |

**BIG RIVERS ELECTRIC CORPORATION**

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**September 10, 2014**

**Item 25)** **In Section 9.2 on page 96 of the IRP, Big Rivers discusses potential resource options to model in its Strategist model. Explain whether nuclear generation is a viable alternative to include in the generation mix.**

**Response)** Potential participation in a future nuclear unit was included in the list of possible options in order to assess whether or not nuclear capacity, based on current estimates of capital and operating characteristics, would be a viable economic alternative upon the occurrence of a need for additional resources. Nuclear capacity was not selected in any cases. If nuclear capacity had been selected by the model, as Big Rivers approached a time of capacity need, the viability of the nuclear option would be defined by conditions in the nuclear generation market including status and availability of nuclear capacity and then-current estimates of costs and operational parameters.

**Witness)** Marlene S. Parsley

**BIG RIVERS ELECTRIC CORPORATION**

**2014 INTEGRATED RESOURCE PLAN**
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**CASE NO. 2014-00166**

**Response to Commission Staff's**
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**September 10, 2014**

**Item 26)** **In Section 9.3 on page 99 of the IRP, Big Rivers states that it has no renewable resources, cogeneration or self-generation, or nonutility resources other than its SEPA allocation in its base case plan. Describe in detail Big Rivers' exploration of each of these resources and its decision to exclude them from the base case plan.**

**Response)** Big Rivers' base case plan does not include the installation or purchase of any new generating capacity, therefore the only resources which fall under the description of resources in the question above are Big Rivers' Members' current SEPA allocations. In the development of the base case plan, and all sensitivity case plans, renewable generation options were allowed to be considered by the Strategist model.

**Witness)** Marlene S. Parsley

**BIG RIVERS ELECTRIC CORPORATION**

**2014 INTEGRATED RESOURCE PLAN**
**OF BIG RIVERS ELECTRIC CORPORATION**
**CASE NO. 2014-00166**

**Response to Commission Staff's**
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**Dated August 20, 2014**

**September 10, 2014**

**Item 27)** **In Section 9.4, page 100 of the IRP, Big Rivers states that capacity purchases from the market were not modeled. Explain in detail why they were not modeled.**

**Response)** As stated in the IRP report, capacity needs in the cases where new resources are needed could be served through a number of ways, including self-build, unit participation, and capacity purchases. The assumption underlying this approach is that pricing associated with non-self-build capacity would be identical to that associated with self-build capacity, and as Big Rivers approached a time of capacity need, the viability of the capacity purchase option would be evaluated further.

**Witness)** Marlene S. Parsley

**BIG RIVERS ELECTRIC CORPORATION**

**2014 INTEGRATED RESOURCE PLAN**
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**CASE NO. 2014-00166**

**Response to Commission Staff's**
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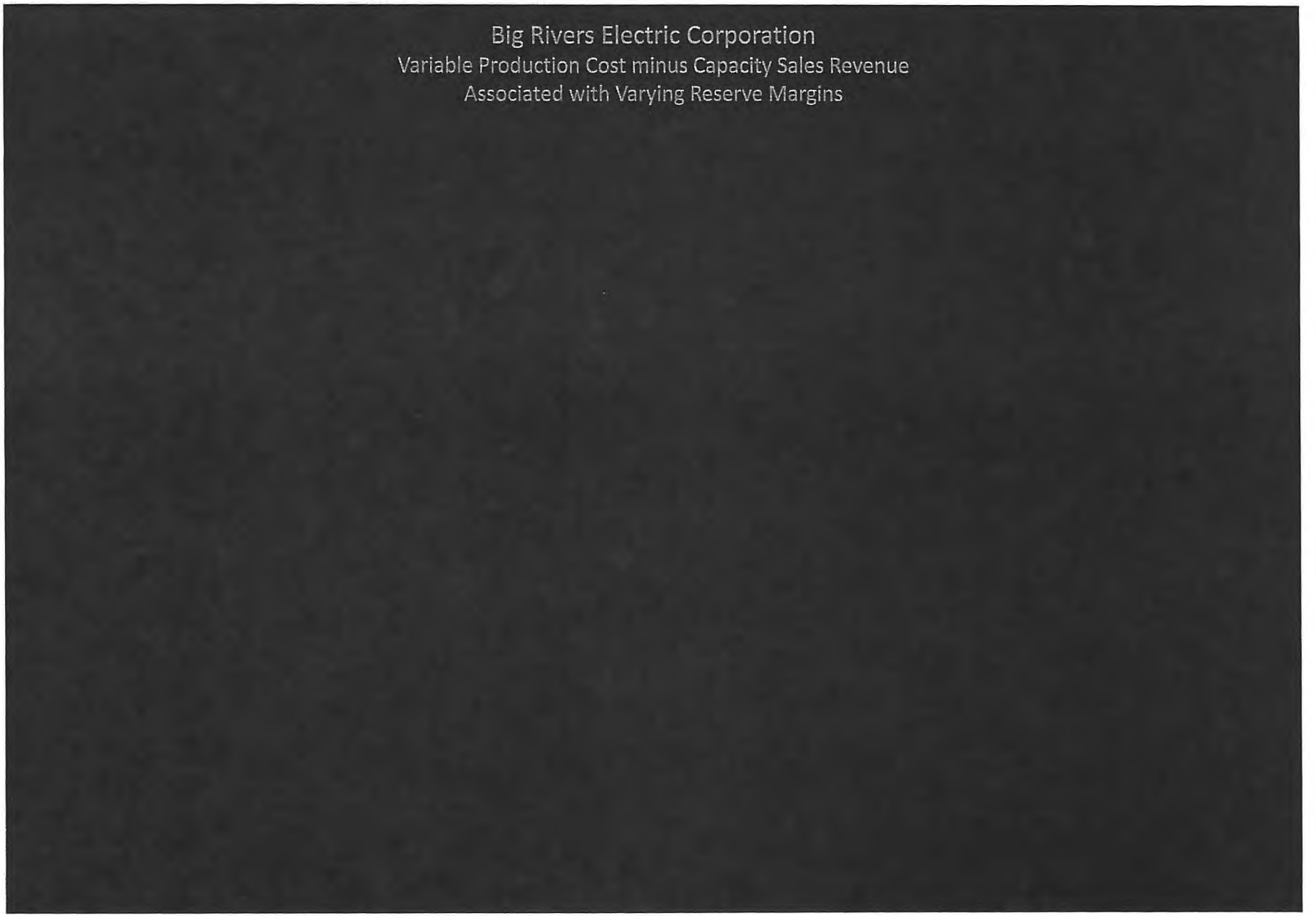
**Item 28)** **In Section 10.3, page 110 of the IRP, Big Rivers discusses a reserve margin study provided by GDS. Specifically, the study demonstrated that Big Rivers' costs decreased as its reserve margin decreased, yet its reliability was not threatened as a member of MISO. Further in Section 7.3, page 83, Big Rivers states that its reserve margin study showed reserve margins in excess of MISO's 2023 requirement over the IRP planning period. Provide a comparison of these reserve margins to the MISO projections and a copy of the GDS reserve margin study.**

**Response)** A reserve margin analysis was conducted by GDS, but a formal report was not produced. Attachment 1, filed under a petition for confidential treatment, contains a summary of PROMOD data associated with different assumed levels of reserve margin on the Big Rivers system. Because the MISO capacity and energy markets are separate, the attached file shows the same sources, uses, and costs of energy for each reserve margin level. This is based on the assumption that Big Rivers could sell excess capacity into the market while still retaining the energy production capabilities of that excess capacity. In the analysis, as reserve margin levels decrease, capacity revenues increase. That factor results in lower net costs at declining reserve margin levels. Because of this effect, and because of Big Rivers' participation in the MISO market, Big Rivers' IRP modeling was performed

assuming that Big Rivers would maintain the MISO Planning Reserve Margin criteria. Attachment 2 provides a comparison of IRP planning period reserve margins and MISO PRM criteria.

**Witness)** Brian D. Smith


Big Rivers Electric Corporation
Variable Production Cost minus Capacity Sales Revenue
Associated with Varying Reserve Margins



Cost Chart

BIG RIVERS ELECTRIC CORPORATION
VARIABLE PRODUCTION COST MINUS CAPACITY SALES REVENUES

| TARGET RESERVE MARGIN | (%) | 9% | 10% | 11% | 12% | 13% | 14% | 15% | 16% | 17% | 18% | 19% | 20% | 21% | 22% | 23.53% |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Uses | | | | | | | | | | | | | | | | |
| Native Load | (GWh) | 9,239 | 9,239 | 9,239 | 9,239 | 9,239 | 9,239 | 9,239 | 9,239 | 9,239 | 9,239 | 9,239 | 9,239 | 9,239 | 9,239 | 9,239 |
| Dump Energy | (GWh) | 326 | 326 | 326 | 326 | 326 | 326 | 326 | 326 | 326 | 326 | 326 | 326 | 326 | 326 | 326 |
| TOTAL USES | (GWh) | 9,564 | 9,564 | 9,564 | 9,564 | 9,564 | 9,564 | 9,564 | 9,564 | 9,564 | 9,564 | 9,564 | 9,564 | 9,564 | 9,564 | 9,564 |
| Energy Sources | | | | | | | | | | | | | | | | |
| Steam Generation | (GWh) | 9,054 | 9,054 | 9,054 | 9,054 | 9,054 | 9,054 | 9,054 | 9,054 | 9,054 | 9,054 | 9,054 | 9,054 | 9,054 | 9,054 | 9,054 |
| Turbine Generation | (GWh) | 209 | 209 | 209 | 209 | 209 | 209 | 209 | 209 | 209 | 209 | 209 | 209 | 209 | 209 | 209 |
| Ext Company Purchase (SEPA) | (GWh) | 267 | 267 | 267 | 267 | 267 | 267 | 267 | 267 | 267 | 267 | 267 | 267 | 267 | 267 | 267 |
| Emergency/Market | (GWh) | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 |
| TOTAL SOURCES | (GWh) | 9,564 | 9,564 | 9,564 | 9,564 | 9,564 | 9,564 | 9,564 | 9,564 | 9,564 | 9,564 | 9,564 | 9,564 | 9,564 | 9,564 | 9,564 |
| Energy Costs | | | | | | | | | | | | | | | | |
| Steam Cost | ($000) | [redacted] | | | | | | | | | | | | | | |
| Turbine Cost | ($000) | | | | | | | | | | | | | | | |
| Variable O&M Cost | ($000) | | | | | | | | | | | | | | | |
| Emission Fee Tax | ($000) | | | | | | | | | | | | | | | |
| Ext Company Purchase Cost (SEPA) | ($000) | | | | | | | | | | | | | | | |
| Emergency/Market Cost | ($000) | | | | | | | | | | | | | | | |
| TOTAL COST | ($000) | | | | | | | | | | | | | | | |
| CO2 Adder | ($/MWh) | | | | | | | | | | | | | | | |
| CO2 Cost | ($000) | | | | | | | | | | | | | | | |
| ADJUSTED ENERGY COST | ($000) | | | | | | | | | | | | | | | |
| Capacity & Load | | | | | | | | | | | | | | | | |
| Native Peak | (MW) | 1,572 | 1,572 | 1,572 | 1,572 | 1,572 | 1,572 | 1,572 | 1,572 | 1,572 | 1,572 | 1,572 | 1,572 | 1,572 | 1,572 | 1,572 |
| Firm Purchase Capacity (SEPA) | (MW) | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 |
| Net Peak | (MW) | 1,394 | 1,394 | 1,394 | 1,394 | 1,394 | 1,394 | 1,394 | 1,394 | 1,394 | 1,394 | 1,394 | 1,394 | 1,394 | 1,394 | 1,394 |
| Company Capacity | (MW) | 1,519 | 1,533 | 1,547 | 1,561 | 1,575 | 1,589 | 1,603 | 1,617 | 1,631 | 1,645 | 1,659 | 1,673 | 1,687 | 1,701 | 1,722 |
| Company Reserve | (MW) | 125 | 139 | 153 | 167 | 181 | 195 | 209 | 223 | 237 | 251 | 265 | 279 | 293 | 307 | 328 |
| Company Reserve Margin | (%) | 9.00% | 10.00% | 11.00% | 12.00% | 13.00% | 14.00% | 15.00% | 16.00% | 17.00% | 18.00% | 19.00% | 20.00% | 21.00% | 22.00% | 23.53% |
| Capacity Sales | | | | | | | | | | | | | | | | |
| Capacity | (MW) | [redacted] | | | | | | | | | | | | | | |
| Capacity Sales Price | ($/kW) | | | | | | | | | | | | | | | |
| Capacity Sales Revenues | ($000) | | | | | | | | | | | | | | | |
| Net Cost | ($000) | | | | | | | | | | | | | | | |
| Reliability | | | | | | | | | | | | | | | | |
| Loss of Load Hours | (Hrs) | 1038 | 982 | 890 | 816 | 767 | 708 | 659 | 605 | 556 | 505 | 523 | 479 | 455 | 420 | 357 |
| % of Energy that is Served via Emergency | (%) | 11.24% | 10.63% | 9.63% | 8.83% | 8.30% | 7.66% | 7.13% | 6.55% | 6.02% | 5.47% | 5.66% | 5.18% | 4.92% | 4.55% | 3.86% |
| Calculated Reserve Margin | (%) | 9.00% | 10.00% | 11.00% | 12.00% | 13.00% | 14.00% | 15.00% | 16.00% | 17.00% | 18.00% | 19.00% | 20.00% | 21.00% | 22.00% | 23.53% |
| Emergency/Market Price Sensitivity | | | | | | | | | | | | | | | | |
| Price: 50 | ($000) | [redacted] | | | | | | | | | | | | | | |
| 100 | ($000) | | | | | | | | | | | | | | | |
| 150 | ($000) | | | | | | | | | | | | | | | |
| 200 | ($000) | | | | | | | | | | | | | | | |
| 250 | ($000) | | | | | | | | | | | | | | | |
| 300 | ($000) | | | | | | | | | | | | | | | |
| 350 | ($000) | | | | | | | | | | | | | | | |
| 400 | ($000) | | | | | | | | | | | | | | | |
| 450 | ($000) | | | | | | | | | | | | | | | |

Minimum Cost for Particular Emergency/Market Price

Big Rivers Electric Corporation
Calculation of Fixed Cost of Combustion Turbine

EIA 2013 AEO Assumptions

| | | | |
|---|---|---|---|
| Advanced Combustion Turbine Cost | (2011 $/kW) | 664.00 | |
| GDP Index 2021 | | 1.33 | |
| GDP Index 2011 | | 1.13 | |
| Advanced Combustion Turbine Cost | (2021 $/kW) | 777.59 | |
| | | | |
| Fixed O&M | (2011 $/kW) | 6.92 | |
| Fixed O&M | (2021 $/kW) | 8.10 | |
| | | | |
| Big Rivers Cost of Capital | (%) | 7.85% | Financial Highlights from 2012 BREC Annual Report |
| Levelized Debt Service for Combustion Turbine (25 Year Financing Term) | (2021 $/kW) | $71.91 | |
| Plus: Fixed O&M Rate | (2021 $/kW) | 8.10 | |
| Total Fixed Cost of Combustion Turbine | (2021 $/kW) | 80.02 | |

| Data Item | <> | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| NativeLoad | | 814.58 | 703.02 | 753.27 | 692.5 | 740.18 | 793.49 | 845.33 | 837.67 | 767.53 | 724.98 | 750.35 | 815.92 | 9,239 |
| DumpEnergy | | 8.42 | | 0.04 | 1.95 | 17.02 | 9.13 | 7.82 | 2.14 | 2.46 | 7.95 | 1.81 | 4.62 | 63 |
| SteamGeneration | | 768.43 | 628.18 | 710.59 | 646.18 | 712.27 | 759.45 | 789.49 | 779.11 | 726.76 | 691.06 | 712.33 | 789.84 | 8,714 |
| TurbineGeneration | | 18.7 | 22.51 | 18.54 | 19.07 | 19.15 | 16.31 | 19.45 | 18.24 | 16.51 | 19.64 | 18.24 | 4.84 | 211 |
| ExtCompanyPurchase | | 23.92 | 19.06 | 11.68 | 11.64 | 17.62 | 24.9 | 42.49 | 39.92 | 21.01 | 11.72 | 19.48 | 23.52 | 267 |
| Emergency | | 11942.25 | 33260.96 | 12505.31 | 17550.17 | 8157.63 | 1965 | 1718.67 | 2536.59 | 5706.95 | 10499.17 | 2116.92 | 2335.11 | 110,295 |
| SteamCost | | | | | | | | | | | | | | |
| TurbineCost | | | | | | | | | | | | | | |
| VariableO&Mcost | | | | | | | | | | | | | | |
| EmissionFeeTax | | | | | | | | | | | | | | |
| DumpCredit | | | | | | | | | | | | | | |
| ExtCompanyPurchaseCost | | | | | | | | | | | | | | |
| EmergencyCost | | | | | | | | | | | | | | |
| EmissionsAllowanceCost | | | | | | | | | | | | | | |
| NativePeak | | 1509 | 1435 | 1397 | 1272 | 1467 | 1529 | 1572 | 1552 | 1481 | 1339 | 1476 | 1502 | 1,572 |
| LoadAdjustment | | | | | | | | | | | | | | |
| Expected Peak | | 1509 | 1435 | 1397 | 1272 | 1467 | 1529 | 1572 | 1552 | 1481 | 1339 | 1476 | 1502 | 1,572 |
| FirmPurchaseCapacity | | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 |
| NetPeak | | 1331 | 1257 | 1219 | 1094 | 1289 | 1351 | 1394 | 1374 | 1303 | 1161 | 1298 | 1324 | 1,394 |
| CompanyCapacity | | 1519.47 | 1519.47 | 1519.47 | 1519.47 | 1519.47 | 1519.47 | 1519.47 | 1519.47 | 1519.47 | 1519.47 | 1519.47 | 1519.47 | 1,519 |
| CompanyReserve | | 188.47 | 262.47 | 300.47 | 425.47 | 230.47 | 168.47 | 125.47 | 145.47 | 216.47 | 358.47 | 221.47 | 195.47 | 125 |
| LossofLoadHours | | 77 | 316 | 95 | 136 | 94 | 36 | 23 | 46 | 53 | 103 | 31 | 28 | 1,038 |

9.00%

| Data Item | <> | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| NativeLoad | | 814.58 | 703.02 | 753.27 | 692.5 | 740.18 | 793.49 | 845.33 | 837.67 | 767.53 | 724.98 | 750.35 | 815.92 | 9,239 |
| DumpEnergy | | 9.22 | | 0.07 | 2.18 | 18.23 | 11.02 | 9.61 | 3 | 3.07 | 9.06 | 2.19 | 5.88 | 74 |
| SteamGeneration | | 769.88 | 630.93 | 711.38 | 647.71 | 714.31 | 761.56 | 791.4 | 780.4 | 727.83 | 692.94 | 712.86 | 791.36 | 8,733 |
| TurbineGeneration | | 18.75 | 22.37 | 18.63 | 19.11 | 19.14 | 16.43 | 19.57 | 18.31 | 16.59 | 17.4 | 18.35 | 4.88 | 210 |
| ExtCompanyPurchase | | 23.92 | 19.06 | 11.68 | 11.64 | 17.62 | 24.9 | 42.49 | 39.92 | 21.01 | 11.72 | 19.48 | 23.52 | 267 |
| Emergency | | 11241.39 | 30644.73 | 11648.76 | 16208.51 | 7333.11 | 1623.78 | 1482.02 | 2043.19 | 5160.5 | 11963.01 | 1847.73 | 2049.4 | 103,246 |
| SteamCost | | | | | | | | | | | | | | |
| TurbineCost | | | | | | | | | | | | | | |
| VariableO&Mcost | | | | | | | | | | | | | | |
| EmissionFeeTax | | | | | | | | | | | | | | |
| DumpCredit | | | | | | | | | | | | | | |
| ExtCompanyPurchaseCost | | | | | | | | | | | | | | |
| EmergencyCost | | | | | | | | | | | | | | |
| EmissionsAllowanceCost | | | | | | | | | | | | | | |
| NativePeak | | 1509 | 1435 | 1397 | 1272 | 1467 | 1529 | 1572 | 1552 | 1481 | 1339 | 1476 | 1502 | 1,572 |
| LoadAdjustment | | | | | | | | | | | | | | |
| Expected Peak | | 1509 | 1435 | 1397 | 1272 | 1467 | 1529 | 1572 | 1552 | 1481 | 1339 | 1476 | 1502 | 1,572 |
| FirmPurchaseCapacity | | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 |
| NetPeak | | 1331 | 1257 | 1219 | 1094 | 1289 | 1351 | 1394 | 1374 | 1303 | 1161 | 1298 | 1324 | 1,394 |
| CompanyCapacity | | 1533.4 | 1533.4 | 1533.4 | 1533.4 | 1533.4 | 1533.4 | 1533.4 | 1533.4 | 1533.4 | 1533.4 | 1533.4 | 1533.4 | 1,533 |
| CompanyReserve | | 202.4 | 276.4 | 314.4 | 439.4 | 244.4 | 182.4 | 139.4 | 159.4 | 230.4 | 372.4 | 235.4 | 209.4 | 139 |
| LossofLoadHours | | 69 | 301 | 89 | 131 | 80 | 35 | 22 | 41 | 49 | 112 | 26 | 27 | 982 |

10.00%

| Data Item | <> | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| NativeLoad | | 814.58 | 703.02 | 753.27 | 692.5 | 740.18 | 793.49 | 845.33 | 837.67 | 767.53 | 724.98 | 750.35 | 815.92 | 9,239 |
| DumpEnergy | | 10.24 | | 0.1 | 2.68 | 20.9 | 13.11 | 11.54 | 4.02 | 3.78 | 10.25 | 2.6 | 7.65 | 87 |
| SteamGeneration | | 771.48 | 633.48 | 713.44 | 650.82 | 718.12 | 763.82 | 793.4 | 781.79 | 728.95 | 694.85 | 713.39 | 792.99 | 8,757 |
| TurbineGeneration | | 18.82 | 22.26 | 18.4 | 18.84 | 19.14 | 16.57 | 19.71 | 18.36 | 16.69 | 17.59 | 18.45 | 5.28 | 210 |
| ExtCompanyPurchase | | 23.92 | 19.06 | 11.68 | 11.64 | 17.62 | 24.9 | 42.49 | 39.92 | 21.01 | 11.72 | 19.48 | 23.52 | 267 |
| Emergency | | 10602.88 | 28219.57 | 9851.44 | 13879.32 | 6193.58 | 1309.62 | 1277.49 | 1616.02 | 4661.8 | 11053.96 | 1634.41 | 1775.41 | 92,076 |
| SteamCost | | | | | | | | | | | | | | |
| TurbineCost | | | | | | | | | | | | | | |
| VariableO&Mcost | | | | | | | | | | | | | | |
| EmissionFeeTax | | | | | | | | | | | | | | |
| DumpCredit | | | | | | | | | | | | | | |
| ExtCompanyPurchaseCost | | | | | | | | | | | | | | |
| EmergencyCost | | | | | | | | | | | | | | |
| EmissionsAllowanceCost | | | | | | | | | | | | | | |
| NativePeak | | 1509 | 1435 | 1397 | 1272 | 1467 | 1529 | 1572 | 1552 | 1481 | 1339 | 1476 | 1502 | 1,572 |
| LoadAdjustment | | | | | | | | | | | | | | |
| Expected Peak | | 1509 | 1435 | 1397 | 1272 | 1467 | 1529 | 1572 | 1552 | 1481 | 1339 | 1476 | 1502 | 1,572 |
| FirmPurchaseCapacity | | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 |
| NetPeak | | 1331 | 1257 | 1219 | 1094 | 1289 | 1351 | 1394 | 1374 | 1303 | 1161 | 1298 | 1324 | 1,394 |
| CompanyCapacity | | 1547.33 | 1547.33 | 1547.33 | 1547.33 | 1547.33 | 1547.33 | 1547.33 | 1547.33 | 1547.33 | 1547.33 | 1547.33 | 1547.33 | 1,547 |
| CompanyReserve | | 216.33 | 290.33 | 328.33 | 453.33 | 258.33 | 196.33 | 153.33 | 173.33 | 244.33 | 386.33 | 249.33 | 223.33 | 153 |
| LossofLoadHours | | 64 | 280 | 68 | 119 | 73 | 34 | 17 | 36 | 45 | 107 | 21 | 26 | 890 |

11.00%

| Data Item | <> | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| NativeLoad | | 814.58 | 703.02 | 753.27 | 692.5 | 740.18 | 793.49 | 845.33 | 837.67 | 767.53 | 724.98 | 750.35 | 815.92 | 9,239 |
| DumpEnergy | | 11.19 | | 0.1 | 3.14 | 22.12 | 15.33 | 13.59 | 4.85 | 4.64 | 11.52 | 3.06 | 9.17 | 99 |
| SteamGeneration | | 772.95 | 635.94 | 713.97 | 652.31 | 719.99 | 766.21 | 795.46 | 783.47 | 730.12 | 696.78 | 713.91 | 794.76 | 8,776 |
| TurbineGeneration | | 18.87 | 22.15 | 18.48 | 18.95 | 19.13 | 16.7 | 19.87 | 17.91 | 16.82 | 17.8 | 18.55 | 5.28 | 211 |
| ExtCompanyPurchase | | 23.92 | 19.06 | 11.68 | 11.64 | 17.62 | 24.9 | 42.49 | 39.92 | 21.01 | 11.72 | 19.48 | 23.52 | 267 |
| Emergency | | 10027.9 | 25865.79 | 9253.07 | 12729.51 | 5561.97 | 1001.6 | 1107.42 | 1217.47 | 4206.79 | 10190.96 | 1463.94 | 1532.24 | 84,159 |
| SteamCost | | | | | | | | | | | | | | |
| TurbineCost | | | | | | | | | | | | | | |
| VariableO&Mcost | | | | | | | | | | | | | | |
| EmissionFeeTax | | | | | | | | | | | | | | |
| DumpCredit | | | | | | | | | | | | | | |
| ExtCompanyPurchaseCost | | | | | | | | | | | | | | |
| EmergencyCost | | | | | | | | | | | | | | |
| EmissionsAllowanceCost | | | | | | | | | | | | | | |
| NativePeak | | 1509 | 1435 | 1397 | 1272 | 1467 | 1529 | 1572 | 1552 | 1481 | 1339 | 1476 | 1502 | 1,572 |
| LoadAdjustment | | | | | | | | | | | | | | |
| Expected Peak | | 1509 | 1435 | 1397 | 1272 | 1467 | 1529 | 1572 | 1552 | 1481 | 1339 | 1476 | 1502 | 1,572 |
| FirmPurchaseCapacity | | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 |
| NetPeak | | 1331 | 1257 | 1219 | 1094 | 1289 | 1351 | 1394 | 1374 | 1303 | 1161 | 1298 | 1324 | 1,394 |
| CompanyCapacity | | 1561.28 | 1561.28 | 1561.28 | 1561.28 | 1561.28 | 1561.28 | 1561.28 | 1561.28 | 1561.28 | 1561.28 | 1561.28 | 1561.28 | 1,561 |
| CompanyReserve | | 230.28 | 304.28 | 342.28 | 467.28 | 272.28 | 210.28 | 167.28 | 187.28 | 258.28 | 400.28 | 263.28 | 237.28 | 167 |
| LossofLoadHours | | 60 | 266 | 64 | 110 | 61 | 28 | 16 | 32 | 41 | 98 | 18 | 22 | 816 |

12.00%

| Data Item | <> | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| NativeLoad | | 814.58 | 703.02 | 753.27 | 692.5 | 740.18 | 793.49 | 845.33 | 837.67 | 767.53 | 724.98 | 750.35 | 815.92 | 9,239 |
| DumpEnergy | | 12.33 | | 0.14 | 3.27 | 21.24 | 17.69 | 15.75 | 6.06 | 5.45 | 12.96 | 3.55 | 10.05 | 108 |
| SteamGeneration | | 774.56 | 638.25 | 713.33 | 652.21 | 719.27 | 768.73 | 797.61 | 785.14 | 731.31 | 698.82 | 714.44 | 796.67 | 8,790 |
| TurbineGeneration | | 18.93 | 21.99 | 18.96 | 19.22 | 19.14 | 16.79 | 20.04 | 17.81 | 16.86 | 17.99 | 18.66 | 4.46 | 211 |
| ExtCompanyPurchase | | 23.92 | 19.06 | 11.68 | 11.64 | 17.62 | 24.9 | 42.49 | 39.92 | 21.01 | 11.72 | 19.48 | 23.52 | 267 |
| Emergency | | 9502.77 | 23708.6 | 9438.64 | 12697.5 | 5388.26 | 763.94 | 948.79 | 858.79 | 3793.42 | 9401.3 | 1315.36 | 1314.78 | 79,132 |
| SteamCost | | | | | | | | | | | | | | |
| TurbineCost | | | | | | | | | | | | | | |
| VariableO&Mcost | | | | | | | | | | | | | | |
| EmissionFeeTax | | | | | | | | | | | | | | |
| DumpCredit | | | | | | | | | | | | | | |
| ExtCompanyPurchaseCost | | | | | | | | | | | | | | |
| EmergencyCost | | | | | | | | | | | | | | |
| EmissionsAllowanceCost | | | | | | | | | | | | | | |
| NativePeak | | 1509 | 1435 | 1397 | 1272 | 1467 | 1529 | 1572 | 1552 | 1481 | 1339 | 1476 | 1502 | 1,572 |
| LoadAdjustment | | | | | | | | | | | | | | |
| Expected Peak | | 1509 | 1435 | 1397 | 1272 | 1467 | 1529 | 1572 | 1552 | 1481 | 1339 | 1476 | 1502 | 1,572 |
| FirmPurchaseCapacity | | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 |
| NetPeak | | 1331 | 1257 | 1219 | 1094 | 1289 | 1351 | 1394 | 1374 | 1303 | 1161 | 1298 | 1324 | 1,394 |
| CompanyCapacity | | 1575.23 | 1575.23 | 1575.23 | 1575.23 | 1575.23 | 1575.23 | 1575.23 | 1575.23 | 1575.23 | 1575.23 | 1575.23 | 1575.23 | 1,575 |
| CompanyReserve | | 244.23 | 318.23 | 356.23 | 481.23 | 286.23 | 224.23 | 181.23 | 201.23 | 272.23 | 414.23 | 277.23 | 251.23 | 181 |
| LossofLoadHours | | 55 | 251 | 73 | 95 | 58 | 23 | 15 | 28 | 39 | 94 | 15 | 21 | 767 |

13.00%

| Data Item | <> | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| NativeLoad | | 814.58 | 703.02 | 753.27 | 692.5 | 740.18 | 793.49 | 845.33 | 837.67 | 767.53 | 724.98 | 750.35 | 815.92 | 9,239 |
| DumpEnergy | | 13.55 | | 0.17 | 3.74 | 22.63 | 19.46 | 18 | 7.59 | 6.31 | 14.49 | 4.04 | 12.04 | 122 |
| SteamGeneration | | 776.19 | 640.41 | 713.89 | 653.68 | 721.13 | 771.44 | 799.81 | 786.9 | 732.55 | 700.9 | 714.95 | 798.82 | 8,811 |
| TurbineGeneration | | 18.99 | 21.86 | 19.07 | 19.05 | 19.17 | 16.04 | 20.22 | 17.85 | 16.87 | 18.19 | 18.58 | 4.51 | 210 |
| ExtCompanyPurchase | | 23.92 | 19.06 | 11.68 | 11.64 | 17.62 | 24.9 | 42.49 | 39.92 | 21.01 | 11.72 | 19.48 | 23.52 | 267 |
| Emergency | | 9030.55 | 21680.75 | 8805.55 | 11858.93 | 4887.4 | 564.22 | 821.19 | 595.65 | 3404.43 | 8649.4 | 1373.84 | 1110.67 | 72,783 |
| SteamCost | | | | | | | | | | | | | | |
| TurbineCost | | | | | | | | | | | | | | |
| VariableO&Mcost | | | | | | | | | | | | | | |
| EmissionFeeTax | | | | | | | | | | | | | | |
| DumpCredit | | | | | | | | | | | | | | |
| ExtCompanyPurchaseCost | | | | | | | | | | | | | | |
| EmergencyCost | | | | | | | | | | | | | | |
| EmissionsAllowanceCost | | | | | | | | | | | | | | |
| NativePeak | | 1509 | 1435 | 1397 | 1272 | 1467 | 1529 | 1572 | 1552 | 1481 | 1339 | 1476 | 1502 | 1,572 |
| LoadAdjustment | | | | | | | | | | | | | | |
| Expected Peak | | 1509 | 1435 | 1397 | 1272 | 1467 | 1529 | 1572 | 1552 | 1481 | 1339 | 1476 | 1502 | 1,572 |
| FirmPurchaseCapacity | | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 |
| NetPeak | | 1331 | 1257 | 1219 | 1094 | 1289 | 1351 | 1394 | 1374 | 1303 | 1161 | 1298 | 1324 | 1,394 |
| CompanyCapacity | | 1589.14 | 1589.14 | 1589.14 | 1589.14 | 1589.14 | 1589.14 | 1589.14 | 1589.14 | 1589.14 | 1589.14 | 1589.14 | 1589.14 | 1,589 |
| CompanyReserve | | 258.14 | 332.14 | 370.14 | 495.14 | 300.14 | 238.14 | 195.14 | 215.14 | 286.14 | 428.14 | 291.14 | 265.14 | 195 |
| LossofLoadHours | | 52 | 233 | 68 | 89 | 56 | 18 | 10 | 17 | 36 | 90 | 20 | 19 | 708 |

14.00%

| Data Item | <> | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| NativeLoad | | 814.58 | 703.02 | 753.27 | 692.5 | 740.18 | 793.49 | 845.33 | 837.67 | 767.53 | 724.98 | 750.35 | 815.92 | 9,239 |
| DumpEnergy | | 12.45 | | 0.23 | 4.22 | 24.04 | 19.92 | 20.37 | 9.34 | 7.4 | 16.04 | 4.57 | 14.19 | 133 |
| SteamGeneration | | 776.55 | 642.45 | 714.43 | 654.98 | 722.91 | 774.73 | 802.13 | 788.78 | 733.86 | 702.98 | 715.45 | 801.08 | 8,830 |
| TurbineGeneration | | 17.98 | 21.71 | 19.18 | 19.03 | 19.28 | 13.36 | 20.36 | 17.9 | 16.38 | 18.36 | 18.78 | 4.56 | 207 |
| ExtCompanyPurchase | | 23.92 | 19.06 | 11.68 | 11.64 | 17.62 | 24.9 | 42.49 | 39.92 | 21.01 | 11.72 | 19.48 | 23.52 | 267 |
| Emergency | | 8566.36 | 19784.81 | 8211.01 | 11071.87 | 4403.24 | 422.99 | 731.41 | 413.7 | 3674.9 | 7953.67 | 1212.58 | 946.79 | 67,393 |
| SteamCost | | | | | | | | | | | | | | |
| TurbineCost | | | | | | | | | | | | | | |
| VariableO&Mcost | | | | | | | | | | | | | | |
| EmissionFeeTax | | | | | | | | | | | | | | |
| DumpCredit | | | | | | | | | | | | | | |
| ExtCompanyPurchaseCost | | | | | | | | | | | | | | |
| EmergencyCost | | | | | | | | | | | | | | |
| EmissionsAllowanceCost | | | | | | | | | | | | | | |
| NativePeak | | 1509 | 1435 | 1397 | 1272 | 1467 | 1529 | 1572 | 1552 | 1481 | 1339 | 1476 | 1502 | 1,572 |
| LoadAdjustment | | | | | | | | | | | | | | |
| Expected Peak | | 1509 | 1435 | 1397 | 1272 | 1467 | 1529 | 1572 | 1552 | 1481 | 1339 | 1476 | 1502 | 1,572 |
| FirmPurchaseCapacity | | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 |
| NetPeak | | 1331 | 1257 | 1219 | 1094 | 1289 | 1351 | 1394 | 1374 | 1303 | 1161 | 1298 | 1324 | 1,394 |
| CompanyCapacity | | 1603.1 | 1603.1 | 1603.1 | 1603.1 | 1603.1 | 1603.1 | 1603.1 | 1603.1 | 1603.1 | 1603.1 | 1603.1 | 1603.1 | 1,603 |
| CompanyReserve | | 272.1 | 346.1 | 384.1 | 509.1 | 314.1 | 252.1 | 209.1 | 229.1 | 300.1 | 442.1 | 305.1 | 279.1 | 209 |
| LossofLoadHours | | 52 | 220 | 63 | 84 | 49 | 13 | 9 | 15 | 38 | 83 | 18 | 15 | 659 |

15.00%

| Data Item | <> | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| NativeLoad | | 814.58 | 703.02 | 753.27 | 692.5 | 740.18 | 793.49 | 845.33 | 837.67 | 767.53 | 724.98 | 750.35 | 815.92 | 9,239 |
| DumpEnergy | | 13.81 | | 0.33 | 4.7 | 25.5 | 21.63 | 22.88 | 11.21 | 8.59 | 17.13 | 5.12 | 16.06 | 147 |
| SteamGeneration | | 778.18 | 644.34 | 714.95 | 656.16 | 724.68 | 776.54 | 804.56 | 790.7 | 735.25 | 704.51 | 715.93 | 803.05 | 8,849 |
| TurbineGeneration | | 18.17 | 21.57 | 19.3 | 19.07 | 19.4 | 13.37 | 20.52 | 17.98 | 16.56 | 18.56 | 18.98 | 4.61 | 208 |
| ExtCompanyPurchase | | 23.92 | 19.06 | 11.68 | 11.64 | 17.62 | 24.9 | 42.49 | 39.92 | 21.01 | 11.72 | 19.48 | 23.52 | 267 |
| Emergency | | 8118.14 | 18042.68 | 7677.53 | 10318.81 | 3968.47 | 313.58 | 643.21 | 278.36 | 3298.14 | 7319.08 | 1073.78 | 803 | 61,855 |
| SteamCost | | | | | | | | | | | | | | |
| TurbineCost | | | | | | | | | | | | | | |
| VariableO&Mcost | | | | | | | | | | | | | | |
| EmissionFeeTax | | | | | | | | | | | | | | |
| DumpCredit | | | | | | | | | | | | | | |
| ExtCompanyPurchaseCost | | | | | | | | | | | | | | |
| EmergencyCost | | | | | | | | | | | | | | |
| EmissionsAllowanceCost | | | | | | | | | | | | | | |
| NativePeak | | 1509 | 1435 | 1397 | 1272 | 1467 | 1529 | 1572 | 1552 | 1481 | 1339 | 1476 | 1502 | 1,572 |
| LoadAdjustment | | | | | | | | | | | | | | |
| Expected Peak | | 1509 | 1435 | 1397 | 1272 | 1467 | 1529 | 1572 | 1552 | 1481 | 1339 | 1476 | 1502 | 1,572 |
| FirmPurchaseCapacity | | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 |
| NetPeak | | 1331 | 1257 | 1219 | 1094 | 1289 | 1351 | 1394 | 1374 | 1303 | 1161 | 1298 | 1324 | 1,394 |
| CompanyCapacity | | 1617.05 | 1617.05 | 1617.05 | 1617.05 | 1617.05 | 1617.05 | 1617.05 | 1617.05 | 1617.05 | 1617.05 | 1617.05 | 1617.05 | 1,617 |
| CompanyReserve | | 286.05 | 360.05 | 398.05 | 523.05 | 328.05 | 266.05 | 223.05 | 243.05 | 314.05 | 456.05 | 319.05 | 293.05 | 223 |
| LossofLoadHours | | 50 | 200 | 57 | 81 | 47 | 11 | 9 | 10 | 37 | 75 | 15 | 13 | 605 |

16.00%

| Data Item | <> | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| NativeLoad | | 814.58 | 703.02 | 753.27 | 692.5 | 740.18 | 793.49 | 845.33 | 837.67 | 767.53 | 724.98 | 750.35 | 815.92 | 9,239 |
| DumpEnergy | | 15.21 | | 0.47 | 5.27 | 26.97 | 24.45 | 25.51 | 13.2 | 9.89 | 18.74 | 5.7 | 17.87 | 163 |
| SteamGeneration | | 779.89 | 646.08 | 715.44 | 657.34 | 726.44 | 779.4 | 807.07 | 792.63 | 736.73 | 706.56 | 716.44 | 805.53 | 8,870 |
| TurbineGeneration | | 18.26 | 21.43 | 19.44 | 19.18 | 19.5 | 13.41 | 20.71 | 18.14 | 16.73 | 18.67 | 19.18 | 4.05 | 209 |
| ExtCompanyPurchase | | 23.92 | 19.06 | 11.68 | 11.64 | 17.62 | 24.9 | 42.49 | 39.92 | 21.01 | 11.72 | 19.48 | 23.52 | 267 |
| Emergency | | 7709.65 | 16439.5 | 7186.29 | 9602.96 | 3581.68 | 234.4 | 568.68 | 173.14 | 2943.2 | 6761.26 | 947.49 | 686.41 | 56,835 |
| SteamCost | | | | | | | | | | | | | | |
| TurbineCost | | | | | | | | | | | | | | |
| VariableO&Mcost | | | | | | | | | | | | | | |
| EmissionFeeTax | | | | | | | | | | | | | | |
| DumpCredit | | | | | | | | | | | | | | |
| ExtCompanyPurchaseCost | | | | | | | | | | | | | | |
| EmergencyCost | | | | | | | | | | | | | | |
| EmissionsAllowanceCost | | | | | | | | | | | | | | |
| NativePeak | | 1509 | 1435 | 1397 | 1272 | 1467 | 1529 | 1572 | 1552 | 1481 | 1339 | 1476 | 1502 | 1,572 |
| LoadAdjustment | | | | | | | | | | | | | | |
| Expected Peak | | 1509 | 1435 | 1397 | 1272 | 1467 | 1529 | 1572 | 1552 | 1481 | 1339 | 1476 | 1502 | 1,572 |
| FirmPurchaseCapacity | | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 |
| NetPeak | | 1331 | 1257 | 1219 | 1094 | 1289 | 1351 | 1394 | 1374 | 1303 | 1161 | 1298 | 1324 | 1,394 |
| CompanyCapacity | | 1630.97 | 1630.97 | 1630.97 | 1630.97 | 1630.97 | 1630.97 | 1630.97 | 1630.97 | 1630.97 | 1630.97 | 1630.97 | 1630.97 | 1,631 |
| CompanyReserve | | 299.97 | 373.97 | 411.97 | 536.97 | 341.97 | 279.97 | 236.97 | 256.97 | 327.97 | 469.97 | 332.97 | 306.97 | 237 |
| LossofLoadHours | | 46 | 188 | 56 | 76 | 42 | 7 | 7 | 9 | 34 | 67 | 13 | 11 | 556 |

17.00%

| Data Item | <> | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| NativeLoad | | 814.58 | 703.02 | 753.27 | 692.5 | 740.18 | 793.49 | 845.33 | 837.67 | 767.53 | 724.98 | 750.35 | 815.92 | 9,239 |
| DumpEnergy | | 16.7 | | 0.62 | 5.89 | 28.44 | 26.57 | 28.24 | 14.88 | 11.33 | 20.43 | 6.37 | 21.22 | 181 |
| SteamGeneration | | 781.69 | 647.65 | 715.94 | 658.59 | 728.17 | 781.53 | 809.69 | 794.72 | 738.36 | 708.54 | 717.02 | 806.61 | 8,889 |
| TurbineGeneration | | 18.35 | 21.33 | 19.57 | 19.19 | 19.61 | 13.44 | 20.89 | 17.82 | 17.41 | 18.87 | 19.39 | 6.43 | 212 |
| ExtCompanyPurchase | | 23.92 | 19.06 | 11.68 | 11.64 | 17.62 | 24.9 | 42.49 | 39.92 | 21.01 | 11.72 | 19.48 | 23.52 | 267 |
| Emergency | | 7317.08 | 14968.89 | 6708.4 | 8963.92 | 3221.76 | 187.08 | 499.8 | 89.64 | 2069.38 | 6277.68 | 829.37 | 583.45 | 51,716 |
| SteamCost | | | | | | | | | | | | | | |
| TurbineCost | | | | | | | | | | | | | | |
| VariableO&Mcost | | | | | | | | | | | | | | |
| EmissionFeeTax | | | | | | | | | | | | | | |
| DumpCredit | | | | | | | | | | | | | | |
| ExtCompanyPurchaseCost | | | | | | | | | | | | | | |
| EmergencyCost | | | | | | | | | | | | | | |
| EmissionsAllowanceCost | | | | | | | | | | | | | | |
| NativePeak | | 1509 | 1435 | 1397 | 1272 | 1467 | 1529 | 1572 | 1552 | 1481 | 1339 | 1476 | 1502 | 1,572 |
| LoadAdjustment | | | | | | | | | | | | | | |
| Expected Peak | | 1509 | 1435 | 1397 | 1272 | 1467 | 1529 | 1572 | 1552 | 1481 | 1339 | 1476 | 1502 | 1,572 |
| FirmPurchaseCapacity | | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 |
| NetPeak | | 1331 | 1257 | 1219 | 1094 | 1289 | 1351 | 1394 | 1374 | 1303 | 1161 | 1298 | 1324 | 1,394 |
| CompanyCapacity | | 1644.92 | 1644.92 | 1644.92 | 1644.92 | 1644.92 | 1644.92 | 1644.92 | 1644.92 | 1644.92 | 1644.92 | 1644.92 | 1644.92 | 1,645 |
| CompanyReserve | | 313.92 | 387.92 | 425.92 | 550.92 | 355.92 | 293.92 | 250.92 | 270.92 | 341.92 | 483.92 | 346.92 | 320.92 | 251 |
| LossofLoadHours | | 45 | 170 | 55 | 66 | 41 | 4 | 7 | 5 | 29 | 61 | 12 | 10 | 505 |

18.00%

| Data Item | <> | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| NativeLoad | | 814.58 | 703.02 | 753.27 | 692.5 | 740.18 | 793.49 | 845.33 | 837.67 | 767.53 | 724.98 | 750.35 | 815.92 | 9,239 |
| DumpEnergy | | 18.18 | | 0.18 | 14.71 | 59.37 | 29.17 | 31.1 | 16.84 | 12.94 | 22.19 | 7.1 | 24 | 236 |
| SteamGeneration | | 783.54 | 649.12 | 706.77 | 669.72 | 764.63 | 784.52 | 812.43 | 796.95 | 740.13 | 710.54 | 717.69 | 809.43 | 8,945 |
| TurbineGeneration | | 18.37 | 21.25 | 21.37 | 18.77 | 16.84 | 13.08 | 21.08 | 17.61 | 17.55 | 19.06 | 19.56 | 6.48 | 211 |
| ExtCompanyPurchase | | 23.92 | 19.06 | 11.68 | 11.64 | 17.62 | 24.9 | 42.49 | 39.92 | 21.01 | 11.72 | 19.48 | 23.52 | 267 |
| Emergency | | 6923.58 | 13588.1 | 13622.57 | 7070.77 | 443.41 | 156.52 | 434.42 | 36.73 | 1771.72 | 5844.29 | 722.35 | 487.97 | 51,102 |
| SteamCost | | | | | | | | | | | | | | |
| TurbineCost | | | | | | | | | | | | | | |
| VariableO&Mcost | | | | | | | | | | | | | | |
| EmissionFeeTax | | | | | | | | | | | | | | |
| DumpCredit | | | | | | | | | | | | | | |
| ExtCompanyPurchaseCost | | | | | | | | | | | | | | |
| EmergencyCost | | | | | | | | | | | | | | |
| EmissionsAllowanceCost | | | | | | | | | | | | | | |
| NativePeak | | 1509 | 1435 | 1397 | 1272 | 1467 | 1529 | 1572 | 1552 | 1481 | 1339 | 1476 | 1502 | 1,572 |
| LoadAdjustment | | | | | | | | | | | | | | |
| Expected Peak | | 1509 | 1435 | 1397 | 1272 | 1467 | 1529 | 1572 | 1552 | 1481 | 1339 | 1476 | 1502 | 1,572 |
| FirmPurchaseCapacity | | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 |
| NetPeak | | 1331 | 1257 | 1219 | 1094 | 1289 | 1351 | 1394 | 1374 | 1303 | 1161 | 1298 | 1324 | 1,394 |
| CompanyCapacity | | 1658.85 | 1658.85 | 1658.85 | 1658.85 | 1658.85 | 1658.85 | 1658.85 | 1658.85 | 1658.85 | 1658.85 | 1658.85 | 1658.85 | 1,659 |
| CompanyReserve | | 327.85 | 401.85 | 439.85 | 564.85 | 369.85 | 307.85 | 264.85 | 284.85 | 355.85 | 497.85 | 360.85 | 334.85 | 265 |
| LossofLoadHours | | 45 | 157 | 115 | 80 | 9 | 4 | 6 | 3 | 29 | 54 | 11 | 10 | 523 |

19.00%

| Data Item | <> | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| NativeLoad | | 814.58 | 703.02 | 753.27 | 692.5 | 740.18 | 793.49 | 845.33 | 837.67 | 767.53 | 724.98 | 750.35 | 815.92 | 9,239 |
| DumpEnergy | | 19.58 | | 0.23 | 14.84 | 61.97 | 32.69 | 33.68 | 19.26 | 14.65 | 24.08 | 8.05 | 26.47 | 256 |
| SteamGeneration | | 785.42 | 650.44 | 707.68 | 670.75 | 766.57 | 787.6 | 815.18 | 799.26 | 742 | 712.6 | 718.52 | 812.28 | 8,968 |
| TurbineGeneration | | 18.27 | 21.16 | 21.44 | 18.63 | 17.61 | 13.55 | 20.97 | 17.74 | 17.68 | 19.26 | 19.76 | 6.2 | 212 |
| ExtCompanyPurchase | | 23.92 | 19.06 | 11.68 | 11.64 | 17.62 | 24.9 | 42.49 | 39.92 | 21.01 | 11.72 | 19.48 | 23.52 | 267 |
| Emergency | | 6540.38 | 12351.91 | 12702.88 | 6311.01 | 352.29 | 126.91 | 375.26 | 11.76 | 1482.33 | 5464.94 | 630.86 | 392.32 | 46,743 |
| SteamCost | | | | | | | | | | | | | | |
| TurbineCost | | | | | | | | | | | | | | |
| VariableO&Mcost | | | | | | | | | | | | | | |
| EmissionFeeTax | | | | | | | | | | | | | | |
| DumpCredit | | | | | | | | | | | | | | |
| ExtCompanyPurchaseCost | | | | | | | | | | | | | | |
| EmergencyCost | | | | | | | | | | | | | | |
| EmissionsAllowanceCost | | | | | | | | | | | | | | |
| NativePeak | | 1509 | 1435 | 1397 | 1272 | 1467 | 1529 | 1572 | 1552 | 1481 | 1339 | 1476 | 1502 | 1,572 |
| LoadAdjustment | | | | | | | | | | | | | | |
| Expected Peak | | 1509 | 1435 | 1397 | 1272 | 1467 | 1529 | 1572 | 1552 | 1481 | 1339 | 1476 | 1502 | 1,572 |
| FirmPurchaseCapacity | | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 |
| NetPeak | | 1331 | 1257 | 1219 | 1094 | 1289 | 1351 | 1394 | 1374 | 1303 | 1161 | 1298 | 1324 | 1,394 |
| CompanyCapacity | | 1672.81 | 1672.81 | 1672.81 | 1672.81 | 1672.81 | 1672.81 | 1672.81 | 1672.81 | 1672.81 | 1672.81 | 1672.81 | 1672.81 | 1,673 |
| CompanyReserve | | 341.81 | 415.81 | 453.81 | 578.81 | 383.81 | 321.81 | 278.81 | 298.81 | 369.81 | 511.81 | 374.81 | 348.81 | 279 |
| LossofLoadHours | | 42 | 144 | 108 | 69 | 8 | 3 | 6 | 2 | 26 | 50 | 11 | 10 | 479 |

20.00%

| Data Item | <> | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| NativeLoad | | 814.58 | 703.02 | 753.27 | 692.5 | 740.18 | 793.49 | 845.33 | 837.67 | 767.53 | 724.98 | 750.35 | 815.92 | 9,239 |
| DumpEnergy | | 21.33 | 0.01 | 0.29 | 16.1 | 64.69 | 35.87 | 36.72 | 23.7 | 13.78 | 26.04 | 9.11 | 29.58 | 277 |
| SteamGeneration | | 787.41 | 651.69 | 708.51 | 672.74 | 769.25 | 790.72 | 818.11 | 804.08 | 740.11 | 714.7 | 719.47 | 815.41 | 8,992 |
| TurbineGeneration | | 18.39 | 21.06 | 21.53 | 18.58 | 17.73 | 13.64 | 21.14 | 17.37 | 18.09 | 19.45 | 19.96 | 6.26 | 213 |
| ExtCompanyPurchase | | 23.92 | 19.06 | 11.68 | 11.64 | 17.62 | 24.9 | 42.49 | 39.92 | 21.01 | 11.72 | 19.48 | 23.52 | 267 |
| Emergency | | 6179.27 | 11216.99 | 11836.04 | 5638.97 | 266.69 | 103.99 | 319.4 | | 2088.89 | 5132.41 | 549.46 | 306.72 | 43,639 |
| SteamCost | | | | | | | | | | | | | | |
| TurbineCost | | | | | | | | | | | | | | |
| VariableO&Mcost | | | | | | | | | | | | | | |
| EmissionFeeTax | | | | | | | | | | | | | | |
| DumpCredit | | | | | | | | | | | | | | |
| ExtCompanyPurchaseCost | | | | | | | | | | | | | | |
| EmergencyCost | | | | | | | | | | | | | | |
| EmissionsAllowanceCost | | | | | | | | | | | | | | |
| NativePeak | | 1509 | 1435 | 1397 | 1272 | 1467 | 1529 | 1572 | 1552 | 1481 | 1339 | 1476 | 1502 | 1,572 |
| LoadAdjustment | | | | | | | | | | | | | | |
| Expected Peak | | 1509 | 1435 | 1397 | 1272 | 1467 | 1529 | 1572 | 1552 | 1481 | 1339 | 1476 | 1502 | 1,572 |
| FirmPurchaseCapacity | | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 |
| NetPeak | | 1331 | 1257 | 1219 | 1094 | 1289 | 1351 | 1394 | 1374 | 1303 | 1161 | 1298 | 1324 | 1,394 |
| CompanyCapacity | | 1686.74 | 1686.74 | 1686.74 | 1686.74 | 1686.74 | 1686.74 | 1686.74 | 1686.74 | 1686.74 | 1686.74 | 1686.74 | 1686.74 | 1,687 |
| CompanyReserve | | 355.74 | 429.74 | 467.74 | 592.74 | 397.74 | 335.74 | 292.74 | 312.74 | 383.74 | 525.74 | 388.74 | 362.74 | 293 |
| LossofLoadHours | | 41 | 135 | 105 | 63 | 8 | 3 | 5 | | 33 | 44 | 10 | 8 | 455 |

21.00%

| Data Item | <> | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| NativeLoad | | 814.58 | 703.02 | 753.27 | 692.5 | 740.18 | 793.49 | 845.33 | 837.67 | 767.53 | 724.98 | 750.35 | 815.92 | 9,239 |
| DumpEnergy | | 23.16 | 0.02 | 0.34 | 17.35 | 67.38 | 37.9 | 39.97 | 26.33 | 15.51 | 28.05 | 10.31 | 32.82 | 299 |
| SteamGeneration | | 789.46 | 652.81 | 709.26 | 674.58 | 771.89 | 793.25 | 821.2 | 806.83 | 742.01 | 716.82 | 720.55 | 818.66 | 9,017 |
| TurbineGeneration | | 18.52 | 21 | 21.65 | 18.57 | 17.86 | 13.16 | 21.34 | 17.26 | 18.23 | 19.65 | 20.16 | 6.32 | 214 |
| ExtCompanyPurchase | | 23.92 | 19.06 | 11.68 | 11.64 | 17.62 | 24.9 | 42.49 | 39.92 | 21.01 | 11.72 | 19.48 | 23.52 | 267 |
| Emergency | | 5828.88 | 10165.27 | 11028.05 | 5054.36 | 186.39 | 81.1 | 270.3 | | 1783.2 | 4832.39 | 473.89 | 231.94 | 39,936 |
| SteamCost | | | | | | | | | | | | | | |
| TurbineCost | | | | | | | | | | | | | | |
| VariableO&Mcost | | | | | | | | | | | | | | |
| EmissionFeeTax | | | | | | | | | | | | | | |
| DumpCredit | | | | | | | | | | | | | | |
| ExtCompanyPurchaseCost | | | | | | | | | | | | | | |
| EmergencyCost | | | | | | | | | | | | | | |
| EmissionsAllowanceCost | | | | | | | | | | | | | | |
| NativePeak | | 1509 | 1435 | 1397 | 1272 | 1467 | 1529 | 1572 | 1552 | 1481 | 1339 | 1476 | 1502 | 1,572 |
| LoadAdjustment | | | | | | | | | | | | | | |
| Expected Peak | | 1509 | 1435 | 1397 | 1272 | 1467 | 1529 | 1572 | 1552 | 1481 | 1339 | 1476 | 1502 | 1,572 |
| FirmPurchaseCapacity | | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 |
| NetPeak | | 1331 | 1257 | 1219 | 1094 | 1289 | 1351 | 1394 | 1374 | 1303 | 1161 | 1298 | 1324 | 1,394 |
| CompanyCapacity | | 1700.67 | 1700.67 | 1700.67 | 1700.67 | 1700.67 | 1700.67 | 1700.67 | 1700.67 | 1700.67 | 1700.67 | 1700.67 | 1700.67 | 1,701 |
| CompanyReserve | | 369.67 | 443.67 | 481.67 | 606.67 | 411.67 | 349.67 | 306.67 | 326.67 | 397.67 | 539.67 | 402.67 | 376.67 | 307 |
| LossofLoadHours | | 41 | 126 | 96 | 56 | 7 | 3 | 5 | | 30 | 42 | 8 | 6 | 420 |

22.00%

| Data Item | <> | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| NativeLoad | | 814.58 | 703.02 | 753.27 | 692.5 | 740.18 | 793.49 | 845.33 | 837.67 | 767.53 | 724.98 | 750.35 | 815.92 | 9,239 |
| DumpEnergy | | 26.05 | 0.06 | 0.44 | 19.11 | 71.23 | 42.18 | 38.97 | 29.16 | 18.28 | 30.74 | 12.32 | 37.07 | 326 |
| SteamGeneration | | 792.74 | 654.32 | 710.32 | 677.16 | 775.69 | 798.67 | 823.12 | 811.66 | 744.97 | 719.88 | 722.39 | 823.17 | 9,054 |
| TurbineGeneration | | 18.66 | 21.01 | 21.74 | 18.56 | 18 | 12.05 | 18.5 | 15.24 | 18.45 | 19.71 | 20.43 | 6.15 | 209 |
| ExtCompanyPurchase | | 23.92 | 19.06 | 11.68 | 11.64 | 17.62 | 24.9 | 42.49 | 39.92 | 21.01 | 11.72 | 19.48 | 23.52 | 267 |
| Emergency | | 5305 | 8685.12 | 9971.17 | 4243.92 | 93 | 55 | 195 | | 1377 | 4401.86 | 373 | 145 | 34,845 |
| SteamCost | | | | | | | | | | | | | | |
| TurbineCost | | | | | | | | | | | | | | |
| VariableO&Mcost | | | | | | | | | | | | | | |
| EmissionFeeTax | | | | | | | | | | | | | | |
| DumpCredit | | | | | | | | | | | | | | |
| ExtCompanyPurchaseCost | | | | | | | | | | | | | | |
| EmergencyCost | | | | | | | | | | | | | | |
| EmissionsAllowanceCost | | | | | | | | | | | | | | |
| NativePeak | | 1509 | 1435 | 1397 | 1272 | 1467 | 1529 | 1572 | 1552 | 1481 | 1339 | 1476 | 1502 | 1,572 |
| LoadAdjustment | | | | | | | | | | | | | | |
| Expected Peak | | 1509 | 1435 | 1397 | 1272 | 1467 | 1529 | 1572 | 1552 | 1481 | 1339 | 1476 | 1502 | 1,572 |
| FirmPurchaseCapacity | | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 |
| NetPeak | | 1331 | 1257 | 1219 | 1094 | 1289 | 1351 | 1394 | 1374 | 1303 | 1161 | 1298 | 1324 | 1,394 |
| CompanyCapacity | | 1722 | 1722 | 1722 | 1722 | 1722 | 1722 | 1722 | 1722 | 1722 | 1722 | 1722 | 1722 | 1,722 |
| CompanyReserve | | 391 | 465 | 503 | 628 | 433 | 371 | 328 | 348 | 419 | 561 | 424 | 398 | 328 |
| LossofLoadHours | | 39 | 108 | 77 | 45 | 4 | 2 | 5 | | 26 | 39 | 7 | 5 | 357 |

23.53%

# Big Rivers Electric Corporation
# 2014 Integrated Resource Plan
# Planning Reserve Margin Comparison

| | Big Rivers Projected Base Case Reserve Margin (%) | MISO ICAP Planning Reserve Margin (%) |
|---|---|---|
| 2013 | 128.66 | |
| 2014 | 124.18 | 14.80 |
| 2015 | 151.99 | 14.90 |
| 2016 | 121.73 | 15.00 |
| 2017 | 97.34 | 15.10 |
| 2018 | 78.12 | 15.10 |
| 2019 | 62.28 | 15.60 |
| 2020 | 38.11 | 16.00 |
| 2021 | 20.16 | 16.40 |
| 2022 | 19.81 | 16.80 |
| 2023 | 19.47 | 17.30 |
| 2024 | 19.08 | 17.30 |
| 2025 | 18.68 | 17.30 |
| 2026 | 18.28 | 17.30 |
| 2027 | 17.88 | 17.30 |
| 2028 | 17.47 | 17.30 |

**BIG RIVERS ELECTRIC CORPORATION**

**2014 INTEGRATED RESOURCE PLAN**
**OF BIG RIVERS ELECTRIC CORPORATION**
**CASE NO. 2014-00166**

**Response to Commission Staff's**
**Initial Request for Information**
**Dated August 20, 2014**

**September 10, 2014**

**Item 29)** **Refer to Section 12.3 of the IRP, page 114. The first full sentence on this page states, "As of the preparation date of this IRP, a forward sale has delayed the idling of the 417 MW Wilson Station through at least the end of February 2015." Confirm that the idling of the Wilson Station has now been postponed until December 31, 2015.**

**Response)** Big Rivers' Attachment Y with MISO which allows for the idling of Wilson Station currently has an idle date of January 1, 2016; however, it is Big Rivers' expectation given current market conditions that Wilson Station will not be idled at that time. Big Rivers anticipates that Wilson Station will be economic to operate for many years to come, adding value to our Members as projected in our Load Concentration Analysis and Mitigation Plan.

**Witness)** Lindsay N. Barron

**BIG RIVERS ELECTRIC CORPORATION**

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**September 10, 2014**

**Item 30) Refer to page 18 of the Study, under Baseline and Efficient Technology Saturations where it states, "The commercial sector utilized regional specific data available from the 2003 Commercial Building Energy Consumption Survey ("CBECS") conducted by the EIA."**

**a. Confirm that the survey data is for 2003.**

**b. If the answer to part a. is affirmative, explain why more recent data was not used.**

**Response)**

a. Yes, the survey data is for 2003.

b. The commercial sector utilized regional specific data available from the 2003 Commercial Buildings Energy Consumption Survey ("CBECS") conducted by the EIA to allocate the fraction of forecasted commercial sales by industry type for each end-use. At the time of the study, the 2003 CBECS data was considered the best source of data required to perform this allocation of forecasted commercial sales. Future CBECS release dates are scheduled for the 2014-2015 timeframe. Please refer to the EIA website for additional information about the CBECS data http://www.eia.gov/consumption/commercial/index.cfm

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1 **Witness)** Russ Pogue

**BIG RIVERS ELECTRIC CORPORATION**

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**Item 31) Refer to page 50 of the Study under MISO Demand Response.**

**a. Discuss what research or analysis Big Rivers has undertaken to evaluate participation in the MidContinent Independent System Operator's ("MISO") demand response market.**

**b. Describe how the May 2014 decision by the U.S. Court of Appeals for the District of Columbia's vacating Federal Energy Regulatory Commission ("FERC") Order 745 impacts MISO's demand response market.[2]**

**Response)**

a. Big Rivers participates in the MISO day ahead and real-time energy and ancillary services market and planning resource auction, which are the markets for demand response products in MISO. Section 8 of Appendix B addresses cost effectiveness of demand response for Big Rivers and discusses how demand response is addressed in MISO. Big Rivers does not currently offer demand response assets into the MISO market; however, Big Rivers monitors the markets for changes applicable to Big Rivers' assets.

[2] *Electric Power Supply Ass'n v. FERC*, 11-1486, et al. (D.C. Cir. May 23, 2014); *Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, 134 FERC ¶ 61,187 (Mar. 15, 2011).

b. FERC Order 745, originally issued on March 15, 2011, established uniform compensation levels for suppliers of demand response resources who participate in day-ahead and real-time energy markets. Order 745 directed Independent System Operators and Regional Transmission Organization ("RTOs") to pay demand response providers full locational marginal prices ("LMP"), and allocated the costs of demand response payments proportionally to all entities that purchase from the relevant energy markets during times when demand response resources enter the market. The D.C. Circuit's opinion vacating Order 745 found that Order 745 exceeded FERC's statutory authority and, even if FERC had such authority, was arbitrary and capricious in violation of the Administrative Procedures Act. On May 13, 2014, The D. C. Circuit Court vacated and remanded Order 745 to FERC. MISO is currently evaluating the impacts of this decision on its markets and processes. The D.C. Circuit Court's action gives MISO an opportunity to re-assess its processes to ensure demand response resources receive fair compensation, and that the costs for demand response are fairly distributed to those who benefit.

**Witnesses)** Russ Pogue and Marlene S. Parsley

**BIG RIVERS ELECTRIC CORPORATION**

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**Item 32)** **Refer to the Benefits section on page 55 of the Study where it states, "Development of the avoided costs is detailed in Section 5.9 of the report."**

**a. Identify the report this statement is referencing.**

**b. If the referenced report is not included as part of the IRP and attachments, provide a copy of the report.**

**Response)**

a. The inclusion of this sentence in the Study was an editorial error and should have been revised to state, "The avoided costs used in the demand response analysis can be found in Appendix C of the report."

b. See the response to sub-part a.

**Witness)** Russ Pogue

**BIG RIVERS ELECTRIC CORPORATION**

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**Item 33) Refer to the Carrying Cost for Capital Equipment section on page 56 of the Study.**

**a. Explain why a blended average is used to determine the Times Interest Earned Ratio ("TIER").**

**b. Explain how weights assigned to the TIERs were developed.**

**c. Explain why different depreciation rates are used for utility ownership and commercial ownership.**

**Response)**

a. The blended average is used to represent the fact that certain demand response costs are typically born by the distribution cooperative (such as the actual control switches) and other costs are borne by the generation and transmission cooperative (central communication systems, for example). Furthermore, it is typical that G&T cooperatives have lower TIER requirements than distribution cooperatives.

b. The weights are an assumption based on the fact that capital expenditures are typically split between a G&T cooperative and its member distribution cooperatives for a demand response program. To estimate the weights of 75% distribution cooperative and 25% G&T cooperative capital investment, Big Rivers assumed the

distribution cooperatives own the switches and the G&T cooperative owns and operates central communication systems and software. We assumed achievement of 5% demand reduction through a moderately aggressive demand response program within 10 years. To achieve that level of penetration, Big Rivers would need to install 24,000 air conditioner switches. At a cost of $190 per switch (assumed install cost for the study), that equates to $4,560,000 invested by distribution cooperatives. Big Rivers estimates the capital contribution from central processing equipment would be between $1,300,000 and $1,500,000, meaning the G&T share would range from 22% to 25% of total capital. However, note that these are estimates for the demand response potential study screening analysis. If Big Rivers were to move forward with a full demand response program, costs would be trued up and the sharing arrangements of cost responsibility between Big Rivers and its Members would be developed at that time.

c. Commercial ownership of equipment is only assumed for distributed generation and energy management systems, which tend to have longer useful lives than direct load control switches. Utility ownership is assumed for all direct load control programs evaluated in the IRP.

**BIG RIVERS ELECTRIC CORPORATION**

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**Witness)** Russ Pogue

**BIG RIVERS ELECTRIC CORPORATION**

**2014 INTEGRATED RESOURCE PLAN**
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**September 10, 2014**

**Item 34) Refer to the Section 9.1.1 of the Study.**

**a. The third sentence on page 59 states that GDS recommended that the Residential Lighting Program begin to offer rebates for LED bulbs. State whether Big Rivers has implemented this recommendation.**

**b. The last sentence in the second paragraph on page 71 states, "GDS recommends that Big Rivers review the program level spending and savings for each incentive scenario, determine which level of incentive investment it plans to commit in the future, and modify its DSM programs to align with the programs included in the program potential evaluation in this study." State whether Big Rivers has implemented this recommendation.**

**Response)**

a. Big Rivers has not begun to offer incentives for residential LED lamps. The DSM/EE working group is currently discussing the effectiveness of offering the incentives.

b. Big Rivers is currently authorized to collect $1 million in base rates and has not yet determined if a change in program level spending is appropriate.

**BIG RIVERS ELECTRIC CORPORATION**

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**Dated August 20, 2014**

**September 10, 2014**

1 **Witness)** Russ Pogue

**BIG RIVERS ELECTRIC CORPORATION**

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**September 10, 2014**

**Item 35)** **Refer to the last paragraph on page 71 of the Study where Tables 10-1 and 10-2 are discussed. Confirm that the reference period should be 2014-2023.**

**Response)** Yes, the reference period should be 2014-2023.

**Witness)** Russ Pogue