SULLIVAN, MOUNTJOY, STAINBACK & MILLER PSC

ATTORNEYS AT LAW

ald M. Sullivan
Jesse T. Mountjoy
Frank Stainback
James M. Miller
Michael A. Fiorella
Allen W. Holbrook
R. Michael Sullivan
Bryan R. Reynolds
Tyson A. Kamuf
Mark W. Starnes
C. Ellsworth Mountjoy
Susan Montalvo-Gesser

February 1, 2010

RECEIVED
FEB 01 2010
PUBLIC SERVICE COMMISSION

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

Re: Big Rivers Electric Corporation

Case No. 2010-00043

Dear Mr. DeRouen:

Enclosed on behalf of Big Rivers Electric Corporation ("Big Rivers") are an original and ten copies of the application of Big Rivers for approval to transfer functional control of its transmission system to Midwest Independent System Operator, Inc. We would point out that each copy of this application has attached as Exhibit 19 a CD ROM containing an electronic copy of the application.

The testimony of Mr. Doying has attached to it a facsimile of his verification. The original of that verification will be forwarded to you in a day or so.

We request that a copy of each pleading, order, and document required to be filed or served in this proceeding be sent to:

James M. Miller
Tyson Kamuf
Sullivan, Mountjoy, Stainback & Miller, P.S.C.
100 St. Ann Street (42303)
P.O. Box 727 (42302-0727)
Owensboro, KY

Douglas L. Beresford
John R. Lilyestrom
Hogan & Hartson, LLP
Columbia Square
555 Thirteenth Street, NW
Washington, D.C. 20004

Telephone (270) 926-4000
Telecopier (270) 683-6694

100 St. Ann Building
PO Box 727
Owensboro, Kentucky
42302-0727

David Crockett
VP System Operations
Big Rivers Electric Corporation
201 Third Street (42420)
P.O. Box 24 (42419-0024)
Henderson, KY

Albert Yockey
VP Governmental Relations
& Enterprise Risk Management
Big Rivers Electric Corporation
201 Third Street (42420)
P.O. Box 24 (42419-0024)
Henderson, KY

Please feel free to contact me if you have any questions regarding this filing.

Sincerely yours,

James M. Miller

James M. Miller

JMM/ej
Enclosures

cc: David Crockett
Albert Yockey
Doug Beresford
John Lilyestrom
Mark David Goss
Hon. Dennis Howard

Service List
February 1, 2010

Gregory A. Troxell
Assistant General Counsel
Midwest ISO, Inc.
P.O. Box 4202 (46082-4202)
701 City Center Drive (46032)
Carmel, Indiana

Mark David Goss
Frost Brown Todd LLC
Suite 2800
250 West Main Street
Lexington, KY 40507-1749

David Crockett
VP System Operations
Big Rivers Electric Corporation
201 Third Street (42420)
P.O. Box 24 (42419-0024)
Henderson, KY

Albert Yockey
VP Governmental Relations
& Enterprise Risk Management
Big Rivers Electric Corporation
201 Third Street (42420)
P.O. Box 24 (42419-0024)
Henderson, KY

Douglas L. Beresford
John R. Lilyestrom
Hogan & Hartson, LLP
Columbia Square
555 Thirteenth Street, NW
Washington, D.C. 2004

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Application of Big Rivers Electric Corporation for Approval to Transfer Functional Control of Its Transmission System to Midwest Independent Transmission System Operator, Inc.	)	Case No. 2010-00043

APPLICATION

1. Big Rivers Electric Corporation ("Big Rivers"), by and through its counsel, submits this application ("Application") seeking authority from the Kentucky Public Service Commission ("Commission") to transfer functional control of its transmission system to Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") effective September 1, 2010.

2. Big Rivers is a rural electric cooperative corporation organized pursuant to KRS Chapter 279. Its mailing address is P.O. Box 24, 201 Third Street, Henderson, Kentucky 42419. Big Rivers owns electric generation facilities, and purchases, transmits and sells electricity at wholesale. It exists for the principal purpose of providing the wholesale electricity requirements of its three distribution cooperative member-owners, which are: Kenergy Corp., Meade County Rural Electric Cooperative Corporation, and Jackson Purchase Energy Corporation (collectively, the "Members"). The Members in turn

provide retail electric service to approximately 111,000 consumer/members located in 22 Western Kentucky counties, to wit: Ballard, Breckenridge, Caldwell, Carlisle, Crittenden, Daviess, Graves, Grayson, Hancock, Hardin, Henderson, Hopkins, Livingston, Lyon, Marshall, McCracken, McLean, Meade, Muhlenberg, Ohio, Union and Webster.

3. This Application and the supporting exhibits, all of which are incorporated herein by reference, contain fully the facts on which the relief requested by Big Rivers is based, a request for the relief sought and references to the particular provisions of law requiring or providing for the relief sought.

4. The Commission may grant Big Rivers the authority to transfer functional control of its transmission system under one or more of KRS 278.020(5), 278.020(6) and 278.218. This Application is filed in compliance with the Commission's applicable regulations, including 807 K.A.R. 5:001, Section 8.

5. The articles of incorporation of Big Rivers, and all amendments thereto, are attached as Exhibit 1 to the application of Big Rivers in *In the Matter of: Application of Big Rivers Electric Corporation, LG&E Energy Marketing Inc., Western Kentucky Energy Corp., WKE Station Two Inc., and WKE Corp., Pursuant to the Public Service Commission Orders in Case Nos. 99-450 and 2000-095, for*

Approval of Amendments to Station Two Agreements, PSC Case No. 2005-00532, and are incorporated by reference.

Introduction

6. Big Rivers seeks to join the Midwest ISO principally to enable it to satisfy the mandatory "Contingency Reserve" standard of the North American Electric Reliability Corporation ("NERC")[1] reliability standard, as approved by the Federal Energy Regulatory Commission ("FERC"), and enforced through NERC's "Regional Entity," SERC Reliability Corporation. Compliance by Big Rivers with the NERC Contingency Reserve standard is both an operational reliability necessity, and a legal requirement to avoid substantial penalties under federal law, including potential fines of up to $1 million per day for each violation.

Background

7. Big Rivers has previously satisfied the NERC Contingency Reserve standard through membership in certain reserve sharing arrangements, most recently the Midwest Contingency Reserve Sharing Group ("MCRSG"). The MCRSG arrangements expired December 31, 2009.

8. When Big Rivers became aware that the MCRSG would likely terminate, it began investigating ways to preserve the MCRSG or

---

[1] See Exhibit DGC-2, attached to Exhibit 2, Testimony of David G. Crockett.

find an alternate way to satisfy the NERC Contingency Reserve standard. At that time Big Rivers was not operating its generating assets, but was trying to implement a transaction to regain control of its generating units by terminating or "unwinding" a series of agreements entered into in 1998 with subsidiaries or affiliates of E.ON U.S., LLC. That transaction, known as the Unwind Transaction, was approved by the Commission on March 6, 2009,[2] and closed July 16, 2009.

9. Following the Unwind Transaction closing, the number of options available to Big Rivers to satisfy the NERC Contingency Reserve standard after the impending termination of the MCRSG at year end narrowed as the result of one or more of the following: legal impediments, cost and lack of sufficient implementation time. With no other feasible option available, on November 20, 2009, Big Rivers' board approved joining the Midwest ISO, starting the process that assured compliance by Big Rivers with the NERC Contingency Reserve standard on January 1, 2010.

Proposed Transfer of Control of Transmission System

10. Big Rivers proposes to transfer functional control of its transmission system to Midwest ISO effective September 1, 2010. For

[2] *In the Matter of: Joint Application of Big Rivers, E.ON, LG&E Energy Marketing, Inc., and Western Kentucky Energy Corporation for Approval to Unwind Lease and Power Purchase Transactions*, PSC Case No. 2007-00455.

this to occur, Big Rivers must have all required consents and approvals in place before August 1, 2010. In addition to the authority required from the Commission to join Midwest ISO, Big Rivers must also obtain the consent of two of its creditors: the United States of America and CoBank, ACB.

11. Midwest ISO is the nation's first regional transmission organization ("RTO"), as approved by FERC in 2001. It is an independent, nonprofit organization that operates the interconnected transmission system of its member companies and administers energy, ancillary services, and financial transmission rights markets for its members and other market participants. It controls facilities in 13 U.S. states and the Canadian province of Manitoba. The organization is headquartered in Carmel, Indiana with operations centers in Carmel and St. Paul, Minnesota.

12. This Application is supported by the verified testimony and exhibits of the following persons:

- **Mark A. Bailey, President and CEO of Big Rivers**. In his testimony (**Exhibit 1**, attached), Mr. Bailey gives an overview of the evolution of the events and decision-making processes that resulted in Big Rivers' decision to join Midwest ISO; the benefits, costs and risks of joining and being a member of Midwest ISO; and Big Rivers' commitment to continue to investigate during the pendency of this proceeding alternate ways for Big Rivers to satisfy the NERC Contingency Reserve standard.

- **David G. Crockett, Vice President System Operations of Big Rivers.** In his testimony (**Exhibit 2**, attached), Mr. Crockett details the reasons why Big Rivers is pursuing membership in Midwest ISO, including describing the NERC Contingency Reserve standard and the legal authority underpinning it; the advantages and costs to Big Rivers of becoming a member of Midwest ISO; the implications of Big Rivers failing to obtain authority to join Midwest ISO; the documents Big Rivers must sign in connection with the membership process; and the timing issues associated with this Application.
- **C. William Blackburn, Senior Vice President Financial & Energy Services & Chief Financial Officer of Big Rivers.** Mr. Blackburn testifies (in **Exhibit 3**, attached) regarding the effect of joining Midwest ISO on the services provided by Big Rivers and other entities; the lack of impact of Midwest ISO membership on the Kentucky integrated resource planning process; the ongoing costs and benefits of Midwest ISO membership; and the creditor

approvals Big Rivers must obtain to transfer functional control of its transmission system to Midwest ISO.

- **<u>Ralph Luciani, Vice President, Charles River Associates</u>.** In his testimony (**Exhibit 4**, attached), Mr. Luciani describes the results of the economic assessment Charles River Associates performed for Big Rivers regarding the alternatives available to Big Rivers to satisfy its NERC Contingency Reserve obligations following termination of the MCRSG.
- **<u>Clair J. Moeller, Vice President of Transmission Asset Management, Midwest ISO</u>.** Mr. Moeller, in his testimony (**Exhibit 5**, attached), describes Midwest ISO; the services provided by Midwest ISO; and the benefits of membership in Midwest ISO.
- **<u>David Zwergel, Senior Director of Regional Operation, Midwest ISO</u>.** Mr. Zwergel provides, in his testimony (**Exhibit 6**, attached), a description of the Midwest ISO reliability coordination function, and how reliability in a portion of Kentucky will be improved as a result of Big Rivers joining Midwest ISO.
- **<u>Richard Doying, Vice President of Market Operations, Midwest ISO</u>.** In **Exhibit 7**, attached, Mr. Doying

describes the Midwest ISO energy and ancillary services markets, the market for Financial Transmission Rights, how those markets operate, and the potential benefits of those markets to Big Rivers and its customers.

13. Big Rivers has executed, will be required to execute or may execute the following agreements, each of which relates to either the contractual terms applicable during the period in which Big Rivers will be integrating into Midwest ISO, or the contractual terms of membership in Midwest ISO:

- **Membership Application for Transmission Facilities Owner**, which Big Rivers filed with Midwest ISO to initiate the membership process. The Transmission-Owning Application for Membership is attached as **Exhibit 8**.
- **Memorandum of Understanding** ("MOU") dated December 11, 2009, by and between the Midwest ISO and Big Rivers. The MOU establishes the relationship between Big Rivers and Midwest ISO during the integration period, which begins with the effective date of the MOU and ends with the earlier of the date Big Rivers completes integration, or 30 days after Big Rivers notifies Midwest ISO that it is not going to complete integration. The MOU states Big Rivers' intent to seek membership in the Midwest ISO, some of the basic requirements for integration and

membership, and certain agreements regarding costs allocations for application, membership, withdrawal from the membership process and withdrawal from membership. The MOU is attached as **Exhibit 9**.

- **Agreement of Transmission Facilities Owners to Organize the Midwest Independent Transmission System Operator, Inc.** ("Midwest ISO Agreement"). This agreement is part of the Midwest ISO FERC Electric Tariff, First Revised Rate Schedule No. 1, and beginning at First Revised Sheet No. 1. The Big Rivers signature page for this agreement will be reported to the FERC in the Midwest ISO's Electric Quarterly Report. The Midwest ISO Agreement is the original source document creating the Midwest ISO, its Board of Directors and its committees. It sets forth the relationship of the RTO to the owners and other stakeholders, and preserves certain rights exclusively to the owners regarding the ability to set and alter their individual rates for the use of their facilities. The Midwest ISO Agreement is attached as **Exhibit 10**.
- **Agreement Between Midwest ISO and Midwest ISO Balancing Authorities Relating to Implementation of TEMT, as Amended on March 14, 2008** ("Balancing Authorities Agreement") signed by Big Rivers on December 21,

2009. This agreement, which becomes effective as to Big Rivers upon its integration into the Midwest ISO, is the Midwest ISO FERC Electric Tariff, First Revised Rate Schedule No. 3. The purpose of this agreement is to delineate the responsibilities as between the Midwest ISO and the Local Balancing Authorities as is necessary to allow the Ancillary Services Markets Tariff to be implemented. The Big Rivers signature page for this agreement will be reported to the FERC in the Midwest ISO's Electric Quarterly Report. The Balancing Authorities Agreement is attached as **Exhibit 11**.

- **Adjacent Balancing Authority Coordination Agreement** between Midwest ISO and Big Rivers. This agreement is effective for the period beginning January 1, 2010, through the earlier of the date Big Rivers completes integration (when Midwest ISO becomes Big Rivers' Balancing Authority), or if it does not complete integration, the date on which one of the parties gives notice of termination. This agreement provides for emergency assistance between neighboring Balancing Authorities, and has been filed by Midwest ISO with the FERC in Docket No. ER10-514-000 as Midwest ISO Rate Schedule No. 27. The Adjacent Balancing Authority Coordination Agreement is attached as **Exhibit 12**.

- **Attachment RR-1 Form of Service Agreement for Real-Time Reserve Services During the Phased Integration** ("Reserves Agreement") dated December 29, 2009, between Midwest ISO and Big Rivers. This tariff service agreement is effective for the period beginning January 1, 2010, through the earlier of August 31, 2010, or full integration into Midwest ISO. The Reserves Agreement is attached as **Exhibit 13**.
- **Attachment KK-1 Form of Service Agreement for Reliability Coordination Service** ("Attachment KK-1 Agreement") dated December 30, 2009, by and between Midwest ISO and Big Rivers. This is the agreement pursuant to which Midwest ISO will commence providing reliability coordination service to Big Rivers on September 1, 2010. Execution of this agreement is required to obtain reserves under Attachment RR, but if a timely integration occurs, this agreement will never go into effect. The Attachment KK-1 Agreement is attached as **Exhibit 14**.
- **Appendix I Supplemental Agreement by and between the Midwest ISO, International Transmission Company and each of the Midwest ISO Transmission Owners** ("Appendix I Supplemental Agreement"). The Appendix I Supplemental Agreement is a multi-party contract between the Midwest ISO,

International Transmission Company ("ITC") and each of the Midwest ISO Transmission Owners to acknowledge the status of ITC as an independent, stand-alone transmission company operating under Appendix I of the Midwest ISO Agreement. There are no financial obligations or additional duties for Big Rivers associated with this particular agreement. The Big Rivers signature page for this agreement will be reported to the FERC in the Midwest ISO's Electric Quarterly Report. The Appendix I Supplemental Agreement is attached as **Exhibit 15**.

- **Funds Trust Agreement.** Big Rivers will receive revenues from the Midwest ISO, as a Transmission Owner. It is required to submit a signature page to the Trust Agreement, which provides that all funds collected by the Midwest ISO on behalf of the Transmission Owners must be wired directly to and held in a "formal trust" with J. P. Morgan as the Trustee without ever being under the control of the Midwest ISO. The Funds Trust Agreement is attached as **Exhibit 16**.
- **Agency Agreement** (Appendix G to the Midwest ISO Agreement). This agreement will only be required of Big Rivers if Big Rivers does not transfer all of its transmission facilities to the control of Midwest ISO. The Agency Agreement is attached

as **Exhibit 17**, although it is very unlikely this agreement will be required.

- **Settlement Agreement between Transmission Owners and Midwest ISO on Filing Rights** ("Settlement Agreement"). Big Rivers may wish to become a signatory to the Settlement Agreement, which was filed in Docket No. RT01-87-010, resolved issues concerning the allocation of filing rights under Section 205 of the Federal Power Act within the Midwest ISO, and was approved by the FERC on March 29, 2005, 110 FERC ¶ 63,380 (2005). The Settlement Agreement is attached as **Exhibit 18**.

14. As a transmission owner member of Midwest ISO, Big Rivers and users of Big Rivers' transmission system will be subject to the Midwest ISO FERC tariff and rate schedule. The full texts of the Midwest ISO tariff and rate schedule are accessible at http://www.midwestiso.org/home by clicking on the words "Ancillary Services/Energy Markets Tariff" found in the lower right corner of that page under the heading "Quick Links."

15. This Application and the attached testimony and exhibits show that Big Rivers must join Midwest ISO and transfer functional control of its transmission system to Midwest ISO to safely provide reliable electric service to its customers at a reasonable cost.

16. For the convenience of the Commission and the parties, Big Rivers attaches as Exhibit 19 to the Application a CDROM containing an electronic version of this Application.

Timing of Action on Application

17. As Mr. Crockett points out in his testimony (Exhibit 2, pages 49-51), for Big Rivers to fully integrate on the target date of September 1, 2010, and to avoid the risk of having to provide Contingency Reserve from its own system at enormous cost, Big Rivers needs a final order of the Commission authorizing the relief sought in this Application by August 1, 2010.

WHEREFORE, Big Rivers requests that by August 1, 2010, the Commission make its order (i) finding that the facts presented by Big Rivers satisfy the requirements of KRS 278.020(5), 278.020(6) and 278.218; (ii) granting Big Rivers the authority to transfer functional control of its transmission system to MISO effective September 1, 2010; and (iii) granting Big Rivers all other relief to which it may appear entitled.

On this the first day of February, 2010.

SULLIVAN, MOUNTJOY, STAINBACK
& MILLER, P.S.C.

James M. Miller

James M. Miller
Tyson Kamuf
100 St. Ann Street, P. O. Box 727
Owensboro, Kentucky 42302-0727
(270) 926-4000

HOGAN & HARTSON, LLP
Douglas L. Beresford
John R. Lilyestrom
Columbia Square
555 Thirteenth Street, NW
Washington, D.C. 20004
(202) 637-5600

Counsel for Big Rivers Electric Corporation

Verification

I, David G. Crockett, the Vice President of System Operations for Big Rivers Electric Corporation, hereby state that I have read the foregoing Application and that the statements contained therein are true and correct to the best of my knowledge and belief, on this the 29th day of January, 2010.

David G. Crockett

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

The foregoing verification statement was SUBSCRIBED AND SWORN to before me by David G. Crockett, the Vice President of System Operations for Big Rivers Electric Corporation, on this the 29th day of January, 2010.

Notary Public, Ky., State at Large
My commission expires: 8-9-10

TABLE OF CONTENTS TO EXHIBITS

Volume I

Exhibit 6	Testimony of David Zwergel, Senior Director of Regional Operation, Midwest ISO
Exhibit 7	Testimony of Richard Doying, Vice President of Market Operations, Midwest ISO
Exhibit 8	Membership Application for Transmission Facilities Owner
Exhibit 9	Memorandum of Understanding

Volume II

Exhibit 10	Agreement of Transmission Facilities Owners to Organize the Midwest Independent Transmission System Operator, Inc.
Exhibit 11	Agreement Between Midwest ISO and Midwest ISO Balancing Authorities Relating to Implementation of TEMT, as Amended on March 14, 2008
Exhibit 12	Adjacent Balancing Authority Coordination Agreement
Exhibit 13	Attachment RR-1 Form of Service Agreement for Real-Time Reserve Services During the Phased Integration
Exhibit 14	Attachment KK-1 Form of Service Agreement for Reliability Coordination Service
Exhibit 15	Appendix I Supplemental Agreement by and between the Midwest ISO, International Transmission Company and each of the Midwest ISO Transmission Owners
Exhibit 16	Funds Trust Agreement
Exhibit 17	Agency Agreement
Exhibit 18	Settlement Agreement between Transmission Owners and Midwest ISO on Filing Rights
Exhibit 19	Disk Containing Electronic Version of Application

COMMONWEALTH OF KENTUCKY
BEFORE THE
PUBLIC SERVICE COMMISSION OF KENTUCKY

Case No. 2010-00___

DIRECT TESTIMONY OF
MARK A. BAILEY

ON BEHALF OF
APPLICANTS

FEBRUARY 2010

DIRECT TESTIMONY OF
MARK A. BAILEY

I. INTRODUCTION

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

A. My name is Mark A. Bailey. My business address is 201 Third Street, Henderson, Kentucky, 42419. I am employed by Big Rivers Electric Corporation ("Big Rivers") as President and Chief Executive Officer ("CEO"), a position I have held since October 2008. Prior to being elected President and CEO by the Big Rivers Board of Directors, I served as Big Rivers' Executive Vice President and Chief Operating Officer beginning in June 2007. Prior to joining Big Rivers, I served as President and CEO of Kenergy Corp. ("Kenergy") from 2004 until acceptance of my position with Big Rivers. Before joining Kenergy, I was employed by American Electric Power Company ("AEP") for nearly 30 years, beginning as an Electrical Engineer in 1974. I held the position of Vice President of AEP subsidiary Indiana Michigan Power Company until AEP's reorganization in 1996, when I became Director-Regions with American Electric Power Service Corporation ("AEPSC"), also a subsidiary of AEP. I was Vice President of Transmission Asset Management for AEPSC from June 2000 until my move to Kenergy. I received a Bachelor of Science Degree in Electrical Engineering from Ohio Northern University in 1974, and a Master of Science Degree in Management from the Massachusetts Institute of Technology in 1988. A copy of my resume is attached as Exhibit MAB-1 to my testimony.

Q. Have you previously testified before this Commission or other regulatory bodies?

A. Yes, I have testified before this Commission previously. In addition, I have testified before state regulatory commissions in Arkansas, Texas, Louisiana, and Oklahoma in support of AEP's merger with Central and South West Corporation.

Q. Please summarize the purpose of your testimony in these proceedings.

A. The purpose of my testimony is to provide an overview of Big Rivers' request for the necessary regulatory approvals from this Commission to join the Midwest Independent Transmission System Operator ("Midwest ISO"). Specifically, I briefly discuss the issue relating to Big Rivers' Contingency Reserve, using the term as it is defined in Mr. Crockett's testimony, Exhibit 2, which has prompted Big Rivers to seek to join the Midwest ISO. I explain when I became aware of the Contingency Reserve issue and how the issue evolved from a routine operating issue with a variety of potentially feasible solutions to the point that Big Rivers' options for resolution of the issue were critically limited. I then summarize the benefits that Big Rivers expects to realize from Midwest ISO membership. I also summarize the potential costs and risks that Big Rivers could experience in becoming a Midwest ISO member, and explain how Big Rivers has sought to mitigate or negate them. Finally, I describe Big Rivers' continuing investigation of potential alternatives to membership in the Midwest ISO, a process that Big Rivers is undertaking to ensure that joining the Midwest ISO remains the best solution for Big Rivers and its members.

II. <u>THE BIG RIVERS CONTINGENCY RESERVE ISSUE</u>

Q. Please explain why Big Rivers is proposing to join the Midwest ISO at this time.

A. As explained more fully by Mr. Crockett in his testimony, Exhibit 2, Big Rivers is proposing to join the Midwest ISO in order to obtain a source of Contingency Reserve to enable it to satisfy mandatory reliability standards established by the North American Electric Reliability Corporation ("NERC") and approved by the Federal Energy Regulatory Commission ("FERC"). Big Rivers is required to satisfy these standards and would be subject to substantial penalties should it fail to do so. Most recently, until December 31, 2009, Big Rivers satisfied these NERC requirements through its participation in the Midwest Contingency Reserve Sharing Group ("MCRSG"), but in the summer of 2009 Big Rivers became increasingly concerned that the agreement pursuant to which the MCRSG operated was likely to terminate at the end of the year. The prospect of the impending dissolution of the MCRSG required Big Rivers to find another means of satisfying its Contingency Reserve obligations. After exploring all of the options available to it, Big Rivers determined that its best option, and indeed the only feasible option that was available to Big Rivers to satisfy this NERC requirement upon termination of the MCRSG, was to commit to join the Midwest ISO.

Q. **Why did Big Rivers conclude that committing to join the Midwest ISO was the only feasible option available to Big Rivers to satisfy its Contingency Reserve obligations?**

A. The Midwest ISO proposed to provide a reserve service that would be available as of the termination of the MCRSG, but the service would be available only to entities that would commit to join the Midwest ISO as transmission-owning members. As Mr. Crockett explains in his testimony, the only other option available for Big Rivers to satisfy its Contingency Reserve obligations immediately upon termination of the MCRSG was to self-supply its Contingency Reserve requirements, and that option was prohibitively expensive. It was not a question of weighing costs and benefits of competing, feasible solutions, but a question of how Big Rivers could fulfill its reliability obligations when its current source of Contingency Reserve ceased to exist.

Q. When did you personally become aware that the MCRSG arrangement might terminate at the end of 2009?

A. My recollection is that I became aware of the Contingency Reserve issue in late April or early May 2009. My recollection of the timing is based on the fact that I had the Contingency Reserve issue put on the agenda for the next meeting of the Board of Directors after I became aware of the matter, as a routine operational and business issue that the Board would need to consider, and that Board meeting took place on May 15, 2009. At that time, I understood that there was a possibility that the MCRSG arrangement would terminate at the end of 2009, but that there also was a possibility that it would not terminate at that time.

Q. When did Big Rivers become aware that the MCRSG arrangement definitely would terminate at the end of 2009?

A. Some uncertainty surrounded Big Rivers' preliminary information about the termination of the MCRSG. Initially, as Mr. Crockett explains in his testimony, Big Rivers believed that it could participate in the Midwest ISO Ancillary Services Market ("ASM") without being a member of the Midwest ISO, and therefore would be able to purchase Contingency Reserve through the ASM. Only in the Spring of 2009 did Big Rivers become aware that the Midwest ISO tariff would prevent it from supplying Contingency Reserve outside of the Midwest ISO footprint.

Even after that, Big Rivers believed that it had a number of options available to it; joining the Midwest ISO was one such option, but there were several others, as Mr. Crockett explains in his testimony. In particular, Big Rivers believed until as late as September 2009 that it would be possible to participate in a reserve sharing arrangement with the Tennessee Valley Authority ("TVA") and other Kentucky utilities, until it was finally advised by TVA that this option would not be available. Big Rivers further believed that it would not incur substantial additional costs in obtaining a replacement source of Contingency Reserve should the MCRSG arrangement terminate.

Big Rivers was notified by the Midwest ISO on July 7, 2009, just a few days before the closing of the unwind of the lease transaction with E.ON U.S., LLC

("E.ON") and its subsidiaries, that the MCRSG arrangement would expire on December 31, 2009. As Mr. Crockett explains more fully in his testimony, Big Rivers sought to extend the termination date through actions before FERC, but FERC denied Big Rivers' request on December 29, 2009. Of course, Big Rivers had been analyzing other options for satisfying its Contingency Reserve obligations before either of these dates, as Mr. Crockett also explains.

III. BENEFITS TO BIG RIVERS OF JOINING THE MIDWEST ISO

Q. What benefits do you believe Big Rivers will experience from joining the Midwest ISO?

A. The anticipated benefits to Big Rivers of membership in the Midwest ISO are described in detail by Mr. Luciani in his testimony, Exhibit 4. Of course, one benefit Big Rivers will obtain is an economically feasible solution to the Contingency Reserve issue, as I have discussed previously. In addition, as a Midwest ISO member, Big Rivers will be able to integrate the commitment and dispatch of its units with the Midwest ISO market, and existing impediments to Big Rivers' trading with the Midwest ISO market, such as wheeling charges, will be reduced. As a result, compared to the self-supply option, Big Rivers should experience reduced costs to serve its native load, through possible increased sales revenues and reduced purchase costs.

Q. How much does Big Rivers expect to save in costs to serve native load?

A. Mr. Luciani has estimated that, compared to the self-supply option, the cost to serve Big Rivers' load will be $11 million less in 2011 and $14 million less in 2014, with a net present value for the 2011-2015 period of $56.7 million in cost savings to serve Big Rivers' native load compared to the self-supply option.

Q. Are there other benefits that have not been quantified?

A. Yes. As Mr. Luciani explains, Big Rivers may benefit from selling additional ancillary services from its generating units to other Midwest ISO members. Mr. Doying explains in his testimony, Exhibit 7, how the Midwest ISO energy market operates, and that Big Rivers' participation in this market gives Big Rivers an opportunity to sell its low cost generation into a broader market than is often available to it today, which will further benefit Big Rivers. Big Rivers may also collect additional wheeling revenues as a result of joining the Midwest ISO, because Midwest ISO members share in wheeling revenues collected by the Midwest ISO. Big Rivers also will benefit from having its transmission planning process conducted along with the Midwest ISO planning process, which will provide more complete information to guide expansions of the Big Rivers transmission system.

IV. POTENTIAL COSTS AND RISKS TO BIG RIVERS OF JOINING THE MIDWEST ISO

Q. What potential costs or risks to Big Rivers do you foresee from Big Rivers joining the Midwest ISO?

A. Big Rivers will incur some additional costs as a result of membership in the Midwest ISO, including administrative fees to the Midwest ISO and administrative charges to FERC. Big Rivers also anticipates that it will incur some costs based on a need for additional staff to support participation in the Midwest ISO once integration has occurred. These costs are discussed by Mr. Luciani and Mr. Blackburn in their respective testimonies. I note, however, that even when these costs are factored in, Mr. Luciani still calculates a $32.3 million net present value benefit to Big Rivers from joining the Midwest ISO for the 2011-2015 timeframe as compared to the self-supply option.

In addition, as Mr. Luciani explains in his testimony, there is some risk that Big Rivers could be required to share in the costs associated with investment in high-voltage transmission in the Midwest ISO region that may be made over the next decade. However, he also explains that Big Rivers may benefit from such improvements.

Q. Has Big Rivers implemented any measures, or does it plan to implement any measures, to reduce or negate the impact of these costs after joining the Midwest ISO?

A. Big Rivers believes that it will enjoy financial benefits from Midwest ISO membership that will help to mitigate those costs, and intends to operate in such a manner as to maximize the additional revenues it may obtain from participation in the Midwest ISO energy market.

Q. Do you believe there is any risk to the Commission's authority over Big Rivers' rates or Big Rivers' transmission planning and siting?

A. No, I do not. Mr. Doying explains that the Commission's authority over Big Rivers' rates and contracts that are subject to its jurisdiction will not be affected. I would also note that Big Rivers is now required to participate in regional transmission planning under existing FERC rules, so participation in the Midwest ISO transmission planning process will not represent a fundamental change from what Big Rivers currently is required to do.

Q. In light of the risks and costs, do you believe that joining the Midwest ISO is still the right thing for Big Rivers?

A. Yes, I do. In light of the need to obtain a means of satisfying Big Rivers' Contingency Reserve obligations, and in light of the benefits I have described, I believe that joining the Midwest ISO is the best option available to Big Rivers at this time. Indeed, I believe that joining the Midwest ISO is necessary for Big Rivers to safely provide reliable electric service to its customers at a reasonable cost. As described by Mr. Crockett and by Midwest ISO witness Moeller in their testimonies, Big Rivers will have the right to withdraw from the Midwest ISO following integration. If Big Rivers determines at any point during its participation in the Midwest ISO that changes to the Midwest ISO tariff and rules impose additional costs and risks on Big Rivers, Big Rivers could pursue its right to withdraw.

V. BIG RIVERS' ONGOING INVESTIGATION OF ALTERNATIVES

Q. Has Big Rivers finally determined that joining the Midwest ISO is the best option available to it to satisfy its Contingency Reserve obligations on a long-term basis?

A. No. As I have explained previously, Big Rivers determined that committing to join the Midwest ISO was the only feasible option to enable it to satisfy its Contingency Reserve obligations when the MCRSG ceased to exist as of December 31, 2009. However, as Mr. Crockett and Mr. Luciani explain in their respective testimonies, Big Rivers is continuing to explore alternatives to Midwest ISO membership, to determine if any other economically viable options exist for Big Rivers to satisfy its Contingency Reserve obligations. In the event that Big Rivers discovers an alternative that is superior to joining the Midwest ISO, Big Rivers will promptly inform the Commission. Big Rivers knows the Commission would expect no less of Big Rivers under the circumstances.

Q. Does this ongoing investigation of alternatives to Midwest ISO membership indicate that Big Rivers is not fully committed to joining the Midwest ISO?

A. Absolutely not. As I have explained, I firmly believe that the benefits to Big Rivers and its members of joining the Midwest ISO are significant, and that joining the Midwest ISO provides significantly greater benefits to Big Rivers than would be achievable under the self-supply option. Big Rivers has applied for and is pursuing membership in Midwest ISO in the good faith belief that this is the best course for Big Rivers to pursue. But joining the Midwest ISO will represent a major change for Big Rivers, and I believe that Big Rivers would be remiss in its obligations to its members were it not to continue to explore and exhaust all potential alternatives.

Q. Does this conclude your testimony at this time?

A. Yes.

VERIFICATION

I verify, state, and affirm that my testimony filed with this verification is true and accurate to the best of my knowledge, information, and belief.

Mark A. Bailey

Mark A. Bailey

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Mark A. Bailey on this the 26th day of January, 2010.

Paula Mitchell

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

MARK ALAN BAILEY

Home: 4008 Shady Hollow Drive
Henderson, Kentucky 42420
270-827-9046

Work: P.O. Box 24 – 201 Third Street
Henderson, Kentucky 42419
270-827-2561

Big Rivers Electric Corp. Henderson, Kentucky Oct. 2008 - present	**President & CEO**
Big Rivers Electric Corp. Henderson, Kentucky June 2007 – Oct. 2008	**Executive Vice President & COO**
Kenergy Corp. Henderson, Kentucky May 2004 – May 2007	**President & CEO** •Responsible to an elected 11 member board for all facets of operations of a distribution electric cooperative serving approximately 54,000 members including 19 large industrial customers in portions of 14 counties in western Kentucky with ~ 160 employees, a peak demand of approximately 1,300 MW, annual kwh sales in excess of 9.4 billion, $300 million in annual revenue, and $210 million in assets
American Electric Power Service Corporation Columbus, Ohio June 2000 – April 2004	**Vice President Transmission Asset Management** •Managed AEP's $2.5B transmission and substation assets located in eleven states, including $100M annual O&M and $250M capital expenditure decisions, as well as engineering and maintenance standards, annual maintenance and capital plans, development of strategic, business and incentive plans, system planning and interconnection agreements, regulatory and legislative policy formation and testimony, and all transmission related contracts
American Electric Power Service Corporation Columbus, Ohio Jan. 1998 – May 2000	**Managing Director, Energy Delivery and Customer Relations** •Responsible for administration of the Energy Delivery and Customer Relations business group consisting of the Transmission, Distribution, Marketing, System Operations, Public Relations, Regulatory functions and the state Presidents' offices including development of strategic, business and incentive plans, operational metrics, performance targets and monitoring systems •Managed Transmission and Distribution Materials Management organization. • Testified before 4 state Commissions in support of AEP's merger w/ CSW
American Electric Power Service Corporation Columbus, Ohio Jan. 1996 – Dec. 1997	**Director – Regions** •Directed the reorganized AEP's six southern distribution regions serving nearly 1,300,000 customers in portions of 5 states with 2,700 company and 2,500 contractor employees •Oversaw the Transmission and Distribution Materials Management organization
Indiana Michigan Power Fort Wayne, Indiana Oct. 1994 - Dec. 1995	**Vice President, Administration** •Oversaw Marketing, Customer Services, Accounting, Rates, and Purchasing and Materials Management Departments as well as the Budgeting Section •Chaired the company's Political Action Disbursements Committee •Coordinated operating company administrative support for the company's three coal fired and one nuclear generating stations (6,200MW)

Indiana Michigan Power Fort Wayne, Indiana 1989 – Sept. 1994	**Vice President, Operations** •Directed four operating divisions serving nearly 520,000 customers in 28 counties in Indiana and Michigan and a total of ~ 1,300 employees •Oversaw Transmission and Distribution, Purchasing and Materials Management, System Operations, General Services and Land Management Departments at corporate headquarters •Coordinated operating company administrative support for the company's three coal fired, one nuclear and five hydro power plants (6,200MW)
Ohio Power Columbus, Ohio 1988 – 1989	**Executive Assistant to the President** •Assisted the AEP Executive Vice President – Operations performing studies and analyses such as ramifications of merging Ohio Power and Columbus Southern Power operating companies and design of a management incentive compensation system •Lobbied on behalf of Ohio Power with the Ohio General Assembly
Ohio Power Cambridge, MA 1987 – 1988	**Division Manager** •Completed course work leading to attainment of a Masters Degree in Management as a Sloan Fellow at the Massachusetts Institute of Technology
Ohio Power Tiffin, Ohio 1985 – 1987	**Division Manager** •Managed all aspects of providing electrical service to 58,000 customers through five operating units consisting of 210 employees
Ohio Power Canton, Ohio 1983 – 1985	**Administrative Assistant to the President** •Coordinated operating company administrative support for the company's five fossil fired power plants (8,120 MW) •Oversaw operation and maintenance of the company's two unit, 48 MW hydro plant •Assisted the President with various studies and assignments
Cardinal Operating Co. Cardinal Plant Brilliant, Ohio 1981 - 1983	**Performance Superintendent** •Directed department of 65 employees responsible for installation and maintenance of the plant's instruments and controls, engineering and thermal performance, and laboratory operations at the three unit, coal fired 1,860 MW plant •Directly supervised start-up & shut-downs of the 600 MW supercritical units
Ohio Power Muskingum River Plant Beverly, Ohio 1979 - 1981	**Production Superintendent** •Directed department responsible for operations of a five unit, coal fired 1,460 MW plant •Directly supervised start-ups & shut-downs of the plant's 600 MW supercritical unit, wrote plant operating procedures and trained operators following major modifications of the 600 MW Unit 5 steam generator & precipitator addition
Ohio Power Gavin Plant Cheshire, Ohio 1975 - 1979	**Performance Engineer** •Various engineering positions of increasing responsibility at the two unit, 2,600 MW coal fired plant. Major areas of involvement included analyzing thermal performance, instrument and control installation and maintenance •Wrote plant operating procedures for all the AEP system's 1,300 MW supercritical units
Ohio Power Portsmouth, Ohio 1974 – 1975	**Electrical Engineer** •Designed, laid out and specified material for construction of distribution facilities to serve retail customers in the Portsmouth division

Education:

- The Massachusetts Institute of Technology, Cambridge, Massachusetts
  Masters of Science in Management, 1988
- The Ohio Northern University, Ada, Ohio
  Bachelor of Science in Electrical Engineering with Distinction, 1974

Honors and Activities:

- Board member - ACES Power Marketing
- Member of Tau Beta Pi National Engineering Honorary
- Member - Order of Kentucky Colonels
- Board Member - Henderson Habitat for Humanity
- Board member - Kentucky Association of Electric Cooperatives
- Board member - Methodist Hospital, Henderson, Kentucky
- Board member - Methodist Hospital Foundation
- Board member - Leadership Kentucky
- Board member - National Renewables Cooperative Organization
- Board member - Kentucky Community & Technical College Foundation
- Member- Henderson Rotary Club

January 2010

COMMONWEALTH OF KENTUCKY
BEFORE THE
PUBLIC SERVICE COMMISSION OF KENTUCKY

Case No. 2010-00___

DIRECT TESTIMONY OF
DAVID G. CROCKETT

ON BEHALF OF
APPLICANTS

FEBRUARY 2010

DIRECT TESTIMONY OF
DAVID G. CROCKETT

I. INTRODUCTION

Q. Please state your name, position, and qualifications.

A. My name is David G. Crockett. I am employed by Big Rivers Electric Corporation ("Big Rivers") as its Vice President System Operations. I have held this position since January 2006. Prior to 2006, I held several positions in the Engineering Department and in 1998 assumed responsibility for the Energy Control Department as Manager over both areas. I have testified on behalf of Big Rivers before the Kentucky Public Service Commission ("KPSC" or the "Commission") in transmission system related cases. Altogether I have been employed by Big Rivers for a total of 37 years. I am a registered Professional Engineer in Kentucky. I graduated in 1972 from the University of Kentucky with a Bachelor of Science degree in Electrical Engineering.

Q. Please summarize the purpose of your testimony in these proceedings.

A. The purpose of my testimony is to address certain issues relating to Big Rivers' request for the Commission's approval to join the Midwest

Independent Transmission System Operator ("Midwest ISO"). Specifically, I explain in detail why Big Rivers proposes to join the Midwest ISO, including the need to meet its obligation to satisfy North American Electric Reliability Corporation ("NERC") standards regarding Contingency Reserve, and the process Big Rivers has undertaken in determining that joining the Midwest ISO is the best alternative available to it to address the Contingency Reserve issue. (Please note that throughout my testimony, I will capitalize terms such as Contingency Reserve that are defined in the NERC Glossary of Terms Used in Reliability Standards. A copy of the NERC Glossary is attached to my testimony as Exhibit DGC-1.) I also identify the advantages to Big Rivers and its members of joining the Midwest ISO. I describe the costs that Big Rivers will incur in the process of integrating with the Midwest ISO. I further address the continuing analysis Big Rivers is undertaking during the pendency of this proceeding to ensure that joining the Midwest ISO is Big Rivers' best available alternative. Finally, I describe the implications to Big Rivers should the Commission either deny this application or fail to approve it in time for Big Rivers to achieve integration with the Midwest ISO by September 1, 2010.

II. BIG RIVERS' REASONS FOR JOINING THE MIDWEST ISO

Q. Can you explain the primary motivation behind Big Rivers' decision to seek to join the Midwest ISO?

A. Under the Federal Power Act ("FPA"), Big Rivers as a registered Balancing Authority is required to comply with certain mandatory reliability standards, including the NERC Disturbance Control Performance standard, BAL-002-0 ("BAL-002"), a copy of which is attached as Exhibit DGC-2 to my testimony. In the past, Big Rivers has complied with these requirements by participating in various Reserve Sharing Groups, the most recent being the Midwest Contingency Reserve Sharing Group ("MCRSG"). However, this Reserve Sharing Group terminated on December 31, 2009, and Big Rivers had to find an alternative way to comply with BAL-002 beginning January 1, 2010. Over the past year, Big Rivers has been diligently exploring all available options for alternative Contingency Reserve arrangements, which I will discuss in my testimony and which Mr. Luciani will discuss in his testimony, Exhibit 4. One of the difficulties in solving Big Rivers' Contingency Reserve problem is the transmission constraints that make many of the alternatives unavailable. After a thorough consideration of all available and possible alternatives, Big Rivers concluded that the only reasonable means of satisfying BAL-002 was to pursue full membership in the Midwest ISO.

Q. Let's start by reviewing the NERC Contingency Reserve requirement. Can you begin by describing NERC?

A. In 2005, pursuant to an amendment to the FPA, Congress assigned to the Federal Energy Regulatory Commission ("FERC") the responsibility and authority for overseeing the reliability of the bulk power system in the United States, including the development and enforcement of mandatory reliability standards. In 2006, FERC certified NERC as the Electric Reliability Organization ("ERO") designated to develop and enforce the reliability standards. NERC has since delegated to eight Regional Entities some of its compliance and monitoring functions, including the imposition of penalties pursuant to Section 215 of the FPA, but retains overall oversight and the ability to independently impose additional monetary and non-monetary penalties, all subject to FERC review. The SERC Reliability Corporation ("SERC") serves as a Regional Entity with delegated authority from NERC for the purpose of proposing and enforcing reliability standards within the SERC Region, which is divided geographically into five diverse sub-regions that are identified as Central, Delta, Gateway, Southeastern and VACAR. The Central sub-region includes the Tennessee Valley Authority

("TVA"), Big Rivers, East Kentucky Power Cooperative, Inc. ("EKPC") and E.ON U.S. Services Inc. for Louisville Gas and Electric Company and Kentucky Utilities Company (I will refer to them collectively in my testimony as "E.ON").

Q. What is Operating Reserve?

A. Operating Reserve is the excess of supply required over anticipated load on a short term basis (usually the next day). NERC defines Operating Reserve as "that capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserve." See Exhibit DGC-1 at 13.

Q. What is Contingency Reserve?

A. Contingency Reserve is a part of the daily Operating Reserve. The NERC BAL-002 requirement deals with Contingency Reserve. Contingency Reserve consists of Spinning and Non-spinning Reserve. Spinning Reserve is "the portion of Operating Reserve consisting of: Generation synchronized to the system and fully available to serve load within the Disturbance Recovery Period following the contingency event; or Load fully removable from the system within the Disturbance Recovery Period following the contingency event." Non-spinning Reserve or Supplemental Reserve is defined as "the portion of Operating Reserve consisting of: Generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within the Disturbance Recovery Period following the contingency event; or Load fully removable from the system within the Disturbance Recovery Period following the contingency event." See Exhibit DGC-1 at 12, 18.

Q. Please describe the NERC Contingency Reserve requirements.

A. The purpose of the BAL-002 standard is to ensure that a Balancing Authority, such as Big Rivers, is able to utilize its Contingency Reserve to balance resources and demand, and return interconnection frequency within defined limits following a Reportable Disturbance. The application of BAL-002 is limited to the loss of supply and does not apply to the loss of load. The operation of an electric power system requires capacity above the current load in order to meet the BAL-002 contingency requirements. Requirement ("R") 1 of BAL-002 provides that each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources, or coordinated adjustments to interchange schedules.

Q. Can BAL-002 requirements be met through a Reserve Sharing Group?

A. Yes. Pursuant to R1.1 of BAL-002, a Balancing Authority may elect to fulfill its Contingency Reserve obligations by participating as a member of a Reserve Sharing Group. In such cases, the Reserve Sharing Group has the same responsibilities and obligations as each Balancing Authority with respect to monitoring and meeting the requirements of BAL-002. Thus, the group Contingency Reserve obligation is allocated across group members to reduce their individual level of required reserve. BAL-002 requires that at a minimum, the Balancing Authority or Reserve Sharing Group carry at least enough Contingency Reserve to cover the most severe single contingency. Such contingency is typically the largest unit being used by the Balancing Authority or by the members of a Reserve Sharing Group in each hour, but it may also be energy imported into the system, if the loss of that import is larger than the loss of any other resource. A Balancing Authority or Reserve Sharing Group must calculate and report compliance with the Disturbance Control Standard for all disturbances greater than or equal to 80% of the magnitude of the Balancing Authority's or of the Reserve Sharing Group's most severe single contingency loss.

In addition, a Balancing Authority or Reserve Sharing Group is required to meet the Disturbance Recovery Criterion within the Disturbance Recovery

Period for 100% of reportable disturbances. The Disturbance Recovery Criterion is:

> R4.1. A Balancing Authority shall return its Area Control Error ("ACE") to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE values just prior to the Disturbance, the Balancing Authority shall return ACE to its pre-Disturbance value.
>
> R4.2. The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance. This period may be adjusted to better suit the needs of an Interconnection based on analysis approved by the NERC Operating Committee.

Q. Does SERC impose additional Contingency Reserve requirements?

A. BAL-002, R2, provides that each Regional Reliability Organization or Reserve Sharing Group shall specify its Contingency Reserve policies, including the permissible mix of Operating Reserve – Spinning and Operating Reserve – Supplemental that may be included in Contingency Reserve. On December 8, 2008, SERC issued its Contingency Reserve policy intended to help the Balancing Authorities within its region to comply with BAL-002. SERC's policy, with respect to Balancing Authorities not participating in a Reserve Sharing Group, provides that the Balancing Authorities are permitted to carry 0 to 100% of their Contingency Reserve in resources that are on-line (Spinning) and under the direct control of the Balancing Authority operator, provided that their Contingency Reserve is sufficient to meet the Disturbance Recovery Criterion of NERC Standard BAL-002 within the Disturbance Recovery Period for 100% of reportable disturbances. Interruptible loads may contribute to Contingency Reserve to the extent that they can be interrupted during the Disturbance Recovery Period.

Another requirement of BAL-002 is to fully restore the Contingency Reserve within the Contingency Reserve Restoration Period for its interconnection (R6). The Contingency Reserve Restoration Period begins at the end of the Disturbance Recovery Period (R6.1) and the default Contingency Reserve Restoration Period is 90 minutes (R6.2). SERC's policy, however, is different for Reserve Sharing Groups than it is for individual Balancing Authorities. SERC's policy with respect to the MCRSG was that 40% must be on-line and Spinning. The remainder can be Supplemental, which can include either quick-start generation or controllable load resources.

Q. What are Big Rivers' Contingency Reserve requirements?

A. For Big Rivers, the most severe single contingency is the loss of its Wilson Unit, which has a maximum capacity of 417 MWs. Without a Reserve Sharing Group arrangement, Big Rivers must maintain 417 MWs of Contingency Reserve to comply with BAL-002 supplied from either generation, controllable load resources, or coordinated adjustments to Interchange Schedules. The Contingency Reserve arrangement must provide for recovery of up to 417 MWs within 15 minutes after the start of the Reportable Disturbance. Prior to January 1, 2010, Big Rivers complied with its BAL-002 requirement by participating in various Reserve Sharing Group arrangements, which substantially reduced Big Rivers' individual Contingency Reserve responsibility. Big Rivers' requirement under the MCRSG Agreement (as defined below) was 32 MWs (this obligation has varied over the years).

Q. Can you provide more detail on how Big Rivers has historically met its Contingency Reserve obligation?

A. Initially, Big Rivers was a member of the East Central Area Reliability ("ECAR") Reserve Sharing Group from 1997 through 2005. The Automatic Reserve Sharing ("ARS") was formally implemented in ECAR on March 24, 1997, and Big Rivers relied on its ECAR membership to meet its Contingency Reserve requirements. ECAR ceased operations in 2006, and the ECAR

Reserve Sharing Group ("ERSG") arrangements were assumed by Reliability*First* Corporation ("RFC"). ERSG entered into a Memorandum of Understanding with RFC, dated January 1, 2006 ("RFC MOU"). This MOU served to replace the ECAR arrangements on a temporary basis and incorporated the terms and conditions set forth in the ECAR Reserve Sharing Group Operation Protocol. The RFC MOU was in effect for one year; it expired on December 31, 2006.

Facing imminent termination of the RFC MOU, Big Rivers was forced to decide whether to form or join another Reserve Sharing Group or to meet its Contingency Reserve requirement on an individual basis. Several parties were discussing forming the MCRSG and after participating in numerous discussions and negotiations with other potential MCRSG and Midwest ISO members, Big Rivers concluded that joining the MCRSG would be the more cost-effective and beneficial option. Participants in the MCRSG developed a new Reserve Sharing Group with a single set of practices and procedures ("MCRSG Operating Protocols") and entered into the Midwest Contingency Reserve Sharing Group Agreement, between former members of ECAR, MAIN and MAPP, dated July 31, 2006, as amended November 30, 2006 ("MCRSG Agreement").

Q. For how long was the MCRSG Agreement intended to remain in effect?

A. Initially, Section 4.2.3 of the MCRSG Agreement provided for termination of the Agreement upon the earlier of (i) the initiation of a Midwest ISO Contingency Reserve market; or (ii) the date that the Midwest ISO begins to perform Balancing Authority functions as the result of existing Balancing Authorities that are members of the Midwest ISO consolidating their Balancing Authority functions. Pursuant to Section 5.3 of the MCRSG Agreement, the parties had also agreed to negotiate in good faith concerning a successor Contingency Reserve Sharing agreement acceptable to the parties that is consistent with the operation and requirements of any such Contingency Reserve market. However, starting in late 2007 and throughout 2008, as the Midwest ISO was developing its Ancillary Services Market ("ASM"), Midwest ISO members discussed a termination date for the MCRSG because the ASM would serve as an alternative and potentially cheaper way for Midwest ISO members to meet the NERC standards. However, the rollout date for the ASM kept getting delayed. When Midwest ISO members became confident on the start date of the ASM, they began the negotiation of a sunset clause for the MCRSG. The ASM finally went into effect on January 6, 2009, which was a delay from its initially planned start date of April 1, 2008.

On January 1, 2008, all of the members of the MCRSG entered into a Memorandum of Understanding, agreeing to cooperate in modifying the MCRSG ARS to accommodate the Operating Protocols of the amended MCRSG to meet NERC requirements. The MCRSG parties were finally able to come to an agreement and executed the Amended and Restated Midwest Contingency Reserve Sharing Group Agreement, between Midwest ISO, Big Rivers, E.ON, on behalf of Louisville Gas and Electric Company and Kentucky Utilities Company, EKPC, Dairyland Power Cooperative, Lincoln Electric System, Manitoba Hydro, MidAmerican Energy Company, Muscatine Power and Water, Nebraska Public Power District, Omaha Public Power District, Western Area Power Administration, dated January 31, 2008 ("Amended MCRSG Agreement"), which was filed with and accepted by FERC. Despite attempts by the Non-Midwest ISO members to extend the termination date of the Amended MCRSG Agreement, Section 4.2.3 of the negotiated Amended MCRSG Agreement provided for termination of the MCRSG on December 31, 2009, unless such date was extended by the MCRSG Contingency Reserve Committee ("CRC"). Pursuant to Section 4.2.1, the MCRSG could also be terminated at any time by an affirmative vote of the CRC. Furthermore, pursuant to Section 6.1.1 of the Amended MCRSG Agreement, any party had the right to withdraw from the MCRSG upon 6 months written notice to the CRC, and no FERC approval was required to effectuate such withdrawal.

Q. Were efforts made to extend the termination date of the MCRSG Agreement?

A. Yes. In February of 2008, Manitoba Hydro made a motion to the CRC to extend the sunset date of the MCRSG until December 31, 2010, arguing that the agreement continued to offer benefits to Midwest ISO members and that the delay in the ASM prompted a delay in the sunset date to allow for a proper assessment of the MCRSG value post ASM. Manitoba Hydro's motion was rejected by the CRC. On July 10, 2008, E.ON presented a formal motion to the CRC to extend the termination date of the Amended MCRSG Agreement to 2015. This motion failed to carry under the governance provisions of the Amended MCRSG Agreement, leaving the December 31, 2009 sunset date intact. Extension of the termination date was a topic of discussion in CRC meetings and conference calls throughout the period from January 2008 to June 2009. In spite of these efforts, the Midwest ISO sent an email notification on July 7, 2009 to all members of the MCRSG stating that the December 31, 2009 sunset date was confirmed and that the members should find alternative arrangements to meet their reserve obligations.

Q. Did Big Rivers encourage extension of the termination date of the MCRSG Agreement?

A. Yes. Big Rivers supported all efforts noted above to extend the termination date. When the Midwest ISO issued a Certificate of Concurrence on August 26, 2009 to terminate the MCRSG, Big Rivers responded with an email dated September 2, 2009 indicating that it did not concur with the termination of the MCRSG. On September 30, 2009, the Midwest ISO filed a notice of cancellation of the MCRSG ("September 30 Notice") with FERC in Docket No. ER09-1769-000. On October 21, 2009, Big Rivers filed with FERC a protest to Midwest ISO's notice of cancellation, arguing that the cancellation of the MCRSG Agreement effective December 31, 2009 would not be just and reasonable with respect to Big Rivers. Big Rivers requested the termination date of MCRSG to be postponed until June 30, 2010, to give Big Rivers and any other similarly situated entities a reasonable and definite period of time to enter into the arrangements that will be necessary to comply with NERC Reliability Standard BAL-002. Non-Midwest ISO members of the MCRSG had been making concerted and continuous efforts to extend the expiration date of the MCRSG, including filing motions before the CRC, conducting negotiations with Midwest ISO and making filings at FERC. Big Rivers participated in these efforts and dedicated extensive time and resources to extend the MCRSG agreement. However, notwithstanding these efforts, FERC accepted the September 30 Notice and permitted the MCRSG Agreement to terminate as of December 31, 2009.

Q. What happens if Big Rivers cannot meet the NERC Contingency Reserve obligation?

A. If Big Rivers cannot meet the NERC Contingency Reserve requirements, it could be subject to penalties of up to $1 million per day for any period of violation. Over the last three years, NERC, in cooperation with the eight Regional Entities charged with compliance enforcement monitoring, and with FERC approval, has been developing its enforcement program. Under the current enforcement scheme, violations are reported to NERC by the Regional Entities, although NERC can also initiate investigations and audits on its own motion. Section 215 of the FPA provides authority for SERC and NERC (with FERC's approval) to impose penalties for violations of the reliability standards by the user, owner or operator of the bulk power system in the amount of up to $1 million per violation per day. The largest penalty imposed by NERC to date was against Florida Power and Light Company ("FPL") in the amount of $25,000,000, pursuant to a Stipulation and Consent Agreement, dated as of September 25, 2009 ("FPL Settlement") and approved by FERC on October 8, 2009 ("FPL Order"). From the $25,000,000, FPL must pay $10,000,000 to the U.S. Treasury, $10,000,000 to NERC, and spend the remaining $5,000,000 on the improvement of its internal NERC compliance programs. The FPL Settlement resolved alleged violations by FPL of a variety of NERC reliability standards. FERC and NERC have approved numerous other financial penalties for violations of NERC standards, but the $25,000,000 FPL Settlement is a serious indication of a shift in NERC's (and FERC's) policy towards greater enforcement and higher penalties.

Q. When did Big Rivers begin considering alternatives to the MCRSG?

A. From the beginning of discussions on adopting a sunset clause to the MCRSG Agreement, Big Rivers has had internal discussions on what alternatives may be available to it to replace its MCRSG arrangements with an alternative arrangement that would meet Big Rivers' Contingency Reserve requirement. Considerable uncertainty existed during 2008 with respect to the exact effective date of the Amended MCRSG Agreement including the sunset termination date. No non-Midwest ISO members implemented alternative solutions until 2009.

Q. Did Big Rivers consider purchasing Contingency Reserve from the Midwest ISO under a different contractual arrangement?

A. Yes, but no such options were available absent a commitment to join the Midwest ISO as a transmission owner. When the Midwest ISO ASM market was being developed, Big Rivers initially thought that Contingency Reserve service would be available to non-Midwest ISO members who were market participants. In April 2009, after the ASM market startup, Big Rivers asked ACES Power Marketing LLC ("APM") to explore with the Midwest ISO the possibility of purchasing the necessary Contingency Reserve within the Midwest ISO ASM. The Midwest ISO informed APM and Big Rivers that its tariff prevented the Midwest ISO from supplying Contingency Reserve outside of the Midwest ISO Regional Transmission Organization ("RTO") footprint.

Q. Did Big Rivers seek assistance from consultants regarding other alternative solutions to Big Rivers' Contingency Reserve needs ?

A. Yes. In April 2009, Big Rivers contacted Dan Becher of DB Consulting LLC who performs consulting services for Big Rivers and other utilities monitoring the activities of the Midwest ISO. Mr. Becher informed Big Rivers that participation in another reserve sharing group like the one administered by the Southwest Power Pool ("SPP") or possibly one that was being discussed involving TVA, E.ON, and EKPC would be the best options available to meet the NERC reliability standards. Big Rivers, a member of APM, a consulting group that works with the Midwest ISO and many other companies in the region, also requested proposals from APM for alternatives that would meet Big Rivers' Contingency Reserve need. In September 2009, APM proposed three potential options. The first option was to purchase quick-start capacity from the Bluegrass combustion turbine ("CT"), which is a 2002 vintage peaker recently purchased by LS Power just outside Louisville. Unfortunately, this is a Siemens unit that cannot meet the 15 minute Disturbance Recovery Period, and this option was not viable. The second option was to join the Midwest ISO (which I will discuss further below). The third option was to build new generation – APM spoke with a developer who stated that quick start / multi cycle CTs are probably at the upper end of installed costs for peaking capacity: $1000-1200/kW. However, even ignoring the cost issues, this option could not be implemented in time to meet the deadline of the December 31, 2009 termination date of the MCRSG. Big Rivers also evaluated a number of other purchase, construction, and self-supply options for meeting its Contingency Reserve obligations. I will discuss each of these options below.

Q. Did Big Rivers consider the option of joining other Reserve Sharing Groups?

A. Yes. In April 2009, Big Rivers was aware of only two other Reserve Sharing Groups operating in the region. These two are the SPP and the Virginia-Carolinas ("VACAR") Reserve Sharing Groups. Big Rivers pursued possibilities of joining both of these groups.

Q. Please describe your efforts with respect to VACAR.

A. VACAR is a sub-region within SERC which has a Reserve Sharing Group for its members. On April 22, 2009, Glen Thweatt, the Manager of Engineering and Energy Control at Big Rivers, at my request, contacted Sam Holeman at Duke Energy to explore the possibility of Big Rivers joining the VACAR Reserve Sharing Group. Mr. Holeman forwarded this request to Tom Abramson of Santee Cooper who I believe is on the VACAR Executive Committee, which is a committee comprised of representatives of the member utilities and makes decisions on behalf of VACAR members. In early May, Mr. Thweatt received a phone call from Mr. Holeman who reported that Mr. Abramson had taken Big Rivers' request before the VACAR Executive Committee, but the Committee decided that it had no interest in opening up complex contractual arrangements that had been in place for over forty years to allow any party outside VACAR, which has only included members from Virginia, North Carolina and South Carolina, to join the VACAR Reserve Sharing Group. Mr. Holeman made it very clear that the members of the VACAR Reserve Sharing Group would not permit Big Rivers to join.

Q. Please describe your efforts to join the SPP Reserve Sharing Group.

A. The SPP has its own Reserve Sharing Group, and Big Rivers has investigated the possibilities to join the SPP Reserve Sharing Group. Such an option cannot be completed at this time due to transmission limitations across paths required to access the SPP's Contingency Reserve. Discussions with SPP began in late April of 2009. SPP staff and the Reserve Sharing Group Committee were open to Big Rivers' participation but stated that Big Rivers would have to obtain a firm transmission path between SPP and Big Rivers. In order to obtain the firm transmission required by SPP, Big Rivers would need approximately 390 MWs of firm transmission from either TVA or Midwest ISO, or a combination of the two. Neither Midwest ISO, nor TVA had sufficient transmission available on their OASIS sites for Big Rivers to purchase.

As a result of the unavailability of this level of firm transmission service (and the cost if it had been available), Big Rivers requested of TVA and Midwest ISO whether it could use their Transmission Reliability Margin ("TRM") capacity to meet the transmission needs requested by SPP. Midwest ISO and SPP have in place a joint operating agreement ("Midwest ISO-SPP JOA"), which provides that both Midwest ISO and SPP would each allow use of its TRM by the other to support the other's reserve sharing power flows. Big Rivers estimated that it would need a transmission requirement of approximately 390 MWs from SPP to Big Rivers and approximately 35 MWs from Big Rivers to SPP. Midwest ISO responded that TRM was not envisioned as a substitute for transmission service and that TRM as described in the Midwest ISO-SPP JOA is applicable to those parties for whom SPP has RTO obligations (where SPP administers transmission service and serves as the Reliability Coordinator), but not for any entity that has contracted to take only reserve sharing services from SPP. Big Rivers concluded that the Midwest ISO TRM would not be available for its participation in the SPP Reserve Sharing Group. And, as noted above, becoming a member of SPP requires physical interconnection or transmission connectivity to SPP, which Big Rivers does not have. TVA also informed Big Rivers that TVA's TRM was not available for a third party (Big Rivers) to participate in a Reserve Sharing Group in which TVA is not a member.

In late May or early June 2009, TVA only had firm transmission capacity available on a monthly basis for 7 of the 12 months in 2010. TVA advised Big Rivers that it should submit a transmission request for the capacity it needs. When the TRM discussions with TVA proved unsuccessful, Big Rivers requested firm point-to-point transmission across TVA in September 2009. The request was for 200 MWs (2 x 100) of firm transmission from Entergy or Associated Electric Cooperative Inc. ("AECI") to Big Rivers and 10 MWs (2 x 5) of transmission from Big Rivers to Entergy or AECI. Including ancillary charges, the TVA point-to-point transmission rate is $23,556/MW-year. For 210 MWs, the cost would be $4.9 million per year. TVA considered the two 100 MW requests separately, and determined in December 2009 that 100

MWs of transmission would require an additional $4.9 million in transmission upgrades on the TVA system and would not be available until mid-2012 at the earliest. The 10 MWs of transmission from Big Rivers to Entergy/AECI was potentially available. However, TVA further noted that a System Impact Study with the Midwest ISO, E.ON and Entergy/AECI would be required before any transmission service could be obtained. Notwithstanding the cost issues, the unavailability of this transmission until 2012 prevents Big Rivers from pursuing this option at this time.

In late May or early June 2009, Midwest ISO had zero available transfer capability ("ATC") for 2010 on its website. In July 2009, Big Rivers was advised to submit a transmission request to Midwest ISO as the best approach to determine whether firm or non-firm transmission service is available between Big Rivers and SPP; however, given the posted ATC of zero and Big Rivers' concerns that making such a request could negatively affect the Midwest ISO's consideration of Big Rivers' request to use the Midwest ISO's TRM capacity, Big Rivers elected not to make such a request at that time.

Q. Did Big Rivers consider the option of joining the PJM or SPP RTOs?

A. Yes. Big Rivers explored the option of joining PJM; however, Big Rivers is not directly interconnected with PJM and would have to either contract for transmission service or build new transmission to interconnect with PJM. The transmission constraints I previously discussed and the timing and expense of building new transmission made this option unattainable for Big Rivers. Participation in the SPP RTO was also not feasible due to the transmission unavailability discussed above.

Q. Did Big Rivers consider using the KII Power Pool Agreement as an option for meeting its Contingency Reserve requirement?

A. Yes. The Kentucky, Indiana, Illinois ("KII") Power Pool Agreement is an old agreement among Big Rivers, Southern Illinois Power Cooperative ("SIPC"), Hoosier Energy Rural Electric Cooperative, Inc. ("SIPC"), and Henderson Municipal Power & Light ("Henderson"). It has both power interchange and transmission provisions. However, the provisions of the KII Agreement would not satisfy the Contingency Reserve requirements that Big Rivers would need under BAL-002 because the KII Agreement provides for emergency power, but not the firm annual obligations nor scheduling provisions required by NERC for Contingency Reserve.

Q. Did Big Rivers consider pursuing purchases from the Southeastern Power Administration ("SEPA")?

A. Yes. SEPA administers the supply and sale of power generated by the Corps of Engineers at various hydro-electric facilities on the Cumberland River. The output of all hydro-electric plants is contractually committed to a number of customers including Big Rivers, EKPC, SIPC, and Henderson. Big Rivers has a right to 178 MW of hydro-electric capacity from SEPA; however, this capacity cannot be scheduled to meet the NERC requirement of recovery within 15 minutes. In the past, it was possible to schedule SEPA capacity, but for the past several years, scheduling has not been possible because the first dam on the Cumberland River had leakage problems and there have been ongoing efforts to repair the problem. However, even prior to the dam leakage, the SEPA capacity could be scheduled day ahead but not within the time period that would be required to meet the NERC 15 minute standard.

Q. Please describe Big Rivers' consideration of the option of purchasing quick-start capacity.

A. Big Rivers considered purchasing quick-start units or capacity. Big Rivers has not found any quick-start units or capacity available for sale that would also have firm transmission available to Big Rivers. Big Rivers has explored whether there are any independent power producers in the region who would sell quick-start capacity to Big Rivers. However, Big Rivers has not found any firm capacity and transmission available for delivery to Big Rivers. E.ON informed Big Rivers that it could sell Big Rivers non-firm quick-start capacity, but this will not meet the requirements of the NERC standard. EKPC informed Big Rivers that it was capacity deficient on-peak and therefore could not commit its quick-start capacity on a firm basis.

Q. Please describe the combined option of relying on smelter curtailment and the SPP Reserve Sharing Group option for meeting the Contingency Reserve requirement.

A. Big Rivers pursued an option which would include (a) a 100 MW limited SPP Reserve Sharing Group participation, (b) 200 MWs of combined load interruption from the two smelters, and (c) the remaining 117 MWs of reserves coming from Big Rivers' generating capacity. Even if Big Rivers could rely on the smelters for the 200 MWs of load reduction, the unavailability until 2012 of 100 MWs of firm transmission capacity across TVA to access SPP Reserve Sharing Group prevents us from utilizing this option.

Q. Please describe the TVA, E.ON and EKPC Reserve Sharing Group option.

A. Big Rivers learned in late April of 2009 that TVA, E.ON and EKPC had been in discussions about the creation of a new Reserve Sharing Group. Big Rivers approached TVA, E.ON and EKPC, and over the period of several months had numerous discussions and negotiations with them, individually and collectively, regarding different options for Big Rivers' membership in this new reserve sharing group. Finally, in mid-September 2009, TVA informed Big Rivers that in the opinion of its General Counsel, TVA is barred from participating in a Reserve Sharing Group arrangement with Big Rivers because it would result in a benefit to Big Rivers which is precluded by the TVA Act and a Consent Judgment to which TVA is a party: To resolve a lawsuit brought by Duke, Entergy, and Southern Company against TVA in the mid-1990s in federal district court in Alabama, TVA entered into a "Consent Judgment" which established how TVA would operate under Section 15d(a) of the TVA Act, specifically with respect to the sale of electric power to "authorized" purchasers. TVA can only sell electric power – which is defined in the Consent Judgment as capacity and/or energy – to those entities with whom TVA had existing exchange arrangements on July 1, 1957. This category does not include Big Rivers (but does include Louisville Gas and Electric Company, Kentucky Utilities Company and EKPC). This is the so-called TVA "fence."

In the Reserve Sharing Group context, if Big Rivers were allowed to use TVA's largest unit as its compliance reporting criteria for BAL-002 (80% of the most severe single contingency of the Reserve Sharing Group), TVA believes that Big Rivers would obtain a benefit, in that none of Big Rivers' generating units would be reportable because TVA has larger units than Big Rivers' Wilson unit. Also, by TVA being a participant in the Reserve Sharing Group, Big Rivers would obtain a benefit of a reduction in the amount of reserves that Big Rivers would otherwise have to carry under applicable reliability standards. TVA's General Counsel believes that this benefit to Big Rivers (lower reserve requirements and BAL-002 compliance reporting) would be made possible through Big Rivers' "use" of TVA generating capacity (albeit on paper), and is, thus, not permissible, regardless of whether TVA is compensated for such use. As such, this option could be pursued only through litigation at FERC or in court, and such litigation against TVA would be costly and time-consuming with the outcome uncertain. Nor could it have been resolved in time for the December 31, 2009 termination date of the MCRSG.

Q. Did Big Rivers consider an EKPC and E.ON option without TVA?

A. Yes. In response to TVA's "fence" restriction, Big Rivers inquired about the creation of a Kentucky Reserve Sharing Group, where Big Rivers, E.ON and

EKPC would share reserves without violating the TVA fence. However, E.ON and EKPC elected to join the Reserve Sharing Group with TVA instead.

Q. Please describe the option of Big Rivers carrying its own reserves.

A. Big Rivers' responsibility under BAL-002 requires it to carry enough reserves to cover its most severe single contingency, which is the loss of the Wilson unit at 417 MWs. Big Rivers has assessed the ramp rates of all of its units to determine how much reserve could be supplied. Although it might be technically possible for Big Rivers to meet its Contingency Reserve obligation through some combination of carrying reserve on its own units and relying on interruption of the smelters, such an option would be unacceptably expensive, as discussed in Mr. Luciani's testimony.

Q. So, when you had explored all possible options to meet Big Rivers' Contingency Reserve obligations, what options were available?

A. Due to the unavailability of generation capacity from any sources directly interconnected with Big Rivers and the unavailability of required transmission capacity to access generation sources remote to Big Rivers, Big Rivers concluded that there were only two options that were possible for Big Rivers to continue to meet its Contingency Reserve obligations as of January

1, 2010: (a) self supply (including smelter interruptions), and (b) participate fully in the Midwest ISO. Mr. Luciani discusses in detail the comparative costs of these alternatives in his testimony, and demonstrates that the self-supply option is prohibitively more expensive than the Midwest ISO option. As a result, Big Rivers elected to pursue participation in the Midwest ISO.

Q. Please describe the option of joining the Midwest ISO.

A. In late September 2009, Big Rivers met with Midwest ISO to discuss Big Rivers becoming a member of Midwest ISO. Joining Midwest ISO would satisfy Big Rivers' Contingency Reserve requirement because Big Rivers would be able to participate in the ASM arrangements currently available to other Midwest ISO members. When Big Rivers learned that using the Midwest ISO ASM without being a member was not an option, Big Rivers began evaluating the possibility of Midwest ISO membership as one of its alternatives. Midwest ISO offered to provide "backstop" service to Big Rivers after expiration of the MCRSG Agreement pursuant to its Real-Time Reserve Services Available to Balancing Authorities During Phased Integration ("Attachment RR"). Contingency Reserve service is available under the Midwest ISO's Attachment RR only for a nine-month period during which the customer is actively working toward full integration into the Midwest ISO. On December 23, 2009, Big Rivers executed a service agreement with the

Midwest ISO under Attachment RR and on January 1, 2010, began taking Contingency Reserve service from the Midwest ISO.

Q. Can you briefly describe the Midwest ISO?

A. Midwest ISO witnesses Moeller, Zwergel and Doying describe the Midwest ISO and its operations in detail in their testimonies (Exhibits 5, 6 and 7, respectively). In summary, the Midwest ISO is the nation's first RTO, as approved by FERC in 2001. It is an independent, nonprofit organization that operates the interconnected transmission system of its member companies and administers energy, ancillary services, and financial transmission rights markets for its members and other market participants. It controls facilities in 13 U.S. states and the Canadian province of Manitoba. The organization is headquartered in Carmel, Indiana with operations centers in Carmel and St. Paul, Minnesota.

Q. Why has Big Rivers decided to join the Midwest ISO?

A. As I discussed above, Big Rivers has determined that joining the Midwest ISO provides it with the only reasonable means currently available to meet its Contingency Reserve obligations. Having Contingency Reserve available is a critical requirement for the continuing reliability of Big Rivers operations.

Not having such reserves would also subject Big Rivers to significant potential penalties from SERC, NERC and FERC. Moreover, participation in the Midwest ISO will provide Big Rivers with additional reliability benefits, as described in the testimony of Midwest ISO witnesses Zwergel and Moeller. And Mr. Luciani describes in his testimony additional benefits available to Big Rivers through its participation in the Midwest ISO's markets.

Q. What goals does Big Rivers plan to achieve by joining the Midwest ISO?

A. Big Rivers' primary goal is to safely provide reliable electric service to its members at a reasonable cost. Participation in the Midwest ISO provides Big Rivers with the best current means of achieving that goal. As described above, Midwest ISO participation will enable Big Rivers to continue to have the Contingency Reserve that is critical to maintaining reliable service in the event of a loss of generation. In addition to the reliability benefits associated with having Contingency Reserve available in the event of a loss of a generating resource, participation in the Midwest ISO will also provide Big Rivers and its members with reliability benefits by providing access to additional generation resources, by providing access to the Midwest ISO's Security Constrained Economic Dispatch as a means to resolve congestion problems, and by utilizing the Midwest ISO's ability to preemptively analyze possible reliability problems across a much broader area than Big Rivers could do on its own. These reliability benefits are discussed in detail in the testimony of Midwest ISO witnesses Zwergel and Moeller.

Q. What impact will joining the Midwest ISO have on Big Rivers' open access transmission tariff?

A. Once Big Rivers joins the Midwest ISO, all portions of its own tariff will no longer be necessary (except for the portion of its tariff providing for local transmission planning). Any party seeking to obtain transmission service over the Big Rivers system would be required to do so under the Midwest ISO tariff, which will be administered by the Midwest ISO. Big Rivers will have the authority to establish, subject to required regulatory approvals, the rates for service within the new Big Rivers zone under the Midwest ISO tariff. Big Rivers intends to propose to FERC that the Midwest ISO tariff be amended for purposes of adding Big Rivers as a new zone to incorporate the rates currently in effect under the Big Rivers tariff.

Q. If Big Rivers were to withdraw from membership in the Midwest ISO at some point in the future, would Big Rivers incur additional costs associated with the withdrawal?

A. Yes, there would be costs associated with Big Rivers withdrawing from the Midwest ISO. The Midwest ISO Finance Department calculated exit fees for Big Rivers for the end of year 2009 and end of year 2015 time periods. The exit fees were estimated to be $6 million and $3.5 million, respectively, declining as capital assets devoted to starting the energy and ancillary services markets are depreciated. Other costs related to withdrawal, however, could increase over time depending on transmission construction activity in the Midwest ISO footprint. Big Rivers understands these calculated exit fees to be good faith estimates of the cost obligations owed to the Midwest ISO pursuant to the terms of withdrawal contained in the Articles V and VII of the Midwest ISO Transmission Owner's Agreement. It should be noted that these exit fees are applicable to post-integration withdrawal; as I explain below, if Big Rivers were to withdraw prior to integration with the Midwest ISO (for reasons other than failure to receive required regulatory approvals), it would only be liable for legal and staff costs incurred by the Midwest ISO in support of the integration process.

III. THE MIDWEST ISO MEMBERSHIP PROCESS

Q. Please describe the process Big Rivers is undertaking in order to become a member of the Midwest ISO, including identifying the agreements that Big Rivers has signed, or will sign, as part of that process.

A. Initially, Big Rivers submitted a fully executed Membership Application for Transmission Facilities Owner ("Application") to the Midwest ISO on December 7, 2009. A copy of the Application is included as Exhibit 8. Along with the Application, Big Rivers submitted a non-refundable membership fee of $15,000. The Application was approved by the Midwest ISO Board of Directors on December 14, 2009. At the time it submitted the Application, Big Rivers entered into a Memorandum of Understanding with the Midwest ISO concerning Big Rivers' request to join the Midwest ISO ("MOU"). A copy of the MOU is included as Exhibit 9.

Big Rivers also has executed the Agreement of Transmission Facilities Owners to Organize the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO Agreement"), a copy of which is included as Exhibit 10. The Midwest ISO Agreement is the original source document creating the Midwest ISO, its Board of Directors, and its committees. It sets forth the relationship of the RTO to the owners and other stakeholders, and preserves certain rights to the owners regarding their ability to set and alter their individual rates for use of their facilities. This agreement would become effective on September 1, 2010, the target date for full integration.

Big Rivers also has executed the Agreement Between Midwest ISO and Midwest ISO Balancing Authorities Relating to Implementation of TEMT, as Amended on March 14, 2008 ("Balancing Authorities Agreement"). This agreement, a copy of which is included as Exhibit 11, sets forth the responsibilities as between the Midwest ISO and the Local Balancing Authorities as necessary to allow implementation of the Midwest ISO ASM tariff.

Big Rivers also has executed an Adjacent Balancing Authority Coordination Agreement with the Midwest ISO. This agreement provides for mutual coordination and assistance between Big Rivers and the Midwest ISO as adjacent Balancing Authorities during the period from January 1, 2010 through the earlier of the date Big Rivers completes full integration into the Midwest ISO or, if it does not complete integration, the date on which one of the parties gives notice of termination. A copy of this agreement is included as Exhibit 12.

Big Rivers also executed an Attachment RR-1 Form of Service Agreement for Real-Time Reserve Services During the Phased Integration ("Reserves Agreement") in order to obtain service under the Midwest ISO's Attachment RR (Real-Time Reserve Services Available to Balancing Authorities During Phased Integration). A copy of the Reserves Agreement is included as

Exhibit 13 to my testimony. The Reserves Agreement provides for Big Rivers to receive reserve services from the Midwest ISO effective January 1, 2010, and continuing until September 30, 2010, and will enable Big Rivers to satisfy its Contingency Reserve obligations during the ongoing process of integrating with the Midwest ISO.

Big Rivers has likewise executed an Attachment KK-1 Form of Service Agreement for Reliability Coordination Service. A copy of this agreement is included as Exhibit 14. This agreement provides for Reliability Coordination Service only for the period prior to Big Rivers' integration into the Midwest ISO. The agreement has an effective date of September 1, 2010, so it will not become effective if Big Rivers is able to complete its Midwest ISO integration by that date.

Q. Are there other agreements that Big Rivers must or may execute in order to become a member of the Midwest ISO?

A. Yes. Big Rivers will be required to execute the Appendix I Supplemental Agreement by and between the Midwest ISO, International Transmission Company and each of the Midwest ISO Transmission Owners. This agreement is a contract among the Midwest ISO, International Transmission Company ("ITC"), and each of the Midwest ISO TOs, to acknowledge ITC's status as an independent, stand-alone transmission company operating under Appendix I of the Midwest ISO Agreement. This agreement does not impose any financial obligations or additional duties upon Big Rivers. A copy of this agreement is included as Exhibit 15.

Big Rivers also will execute the Funds Trust Agreement, a copy of which is included as Exhibit 16. As a Midwest ISO TO, Big Rivers will receive revenues from the Midwest ISO. The Funds Trust Agreement provides that all funds collected by the Midwest ISO on behalf of the TOs must be wired directly to, and held in a "formal trust" by, J. P. Morgan, without those funds ever being under the Midwest ISO's control.

Big Rivers may also execute an Agency Agreement, which is contained as Appendix G to the Midwest ISO Agreement, and a copy of which is included as Exhibit 17. However, this agreement will only be required of Big Rivers if Big Rivers does not transfer all of its transmission facilities to the functional control of the Midwest ISO. It is very unlikely that Big Rivers will be required to enter into this agreement.

Finally, Big Rivers may wish to become a signatory to the Settlement Agreement between Transmission Owners and Midwest ISO on Filing Rights ("Settlement Agreement"), which resolved certain issues concerning the allocation of filing rights under FPA section 205 within the Midwest ISO, and which was approved by FERC on March 29, 2005, in Docket No. RT01-87-010. A copy of the Settlement Agreement is included as Exhibit 18.

Q. Other than this Commission, are there any other regulatory bodies that will need to approve Big Rivers becoming a member of the Midwest ISO?

A. Yes. Certain agreements into which Big Rivers will enter in conjunction with Midwest ISO membership will be required to be filed with, or reported to, FERC by the Midwest ISO.

IV. COSTS TO BIG RIVERS OF INTEGRATING WITH THE MIDWEST ISO

Q. What efforts will Big Rivers need to undertake during the period that it is preparing to fully integrate its transmission system with that of the Midwest ISO?

A. Big Rivers will undertake a number of activities in preparation for full integration into the Midwest ISO transmission system. First, Big Rivers will be involved in monthly billing settlement processes with the Midwest ISO for the energy provided under the Attachment RR reserve services arrangement throughout the integration period. Second, Big Rivers will work with the

Midwest ISO to add the communications and computer interface equipment and services necessary to allow for the integration. Third, Big Rivers will provide the required power supply contracts for consideration of Grandfathered Agreement ("GFA") status by the Midwest ISO. Fourth, Big Rivers will provide system load data to the Midwest ISO so that the Midwest ISO can include the load into the commercial model underpinning the Midwest ISO Energy and Operating Reserves Markets.

Fifth, Big Rivers will provide transmission system data and generating unit data and any other operational information needed by the Midwest ISO to perform its tasks in adding Big Rivers into their Network Model in preparation for the integration (including identifying the transmission assets to be transferred to the functional control of the Midwest ISO). Sixth, Big Rivers will work with the Midwest ISO and TVA to ensure a smooth transition from receiving Reliability Coordinator services from TVA to receiving Reliability Coordinator services from the Midwest ISO. Seventh, Big Rivers will work with the Midwest ISO to assign Auction Revenue Rights ("ARR") and Financial Transmission Rights during the integration process. Finally, Big Rivers will work with the Midwest ISO on all training of personnel and testing of systems to provide for a smooth integration of Big Rivers into the Midwest ISO's market operations.

Q. Can you describe the effect of GFA status on Big Rivers' contracts?

A. Under the Midwest ISO ASM tariff, transmission owners have the ability to "grandfather" firm power and transmission contracts from certain requirements otherwise applicable to load served under the tariff. Grandfathering is available for such contracts, provided they were executed or committed to prior to September 16, 1998. There are four GFA options: "Carved out" and Options A, B, and C. "Carved out" GFAs are not subject to the obligation to submit financially binding Day-Ahead Schedules in Midwest ISO markets and are exempt from congestion and loss charges. Carved out GFA status is not available for contracts between a cooperative and its members. Options A and C are available for contracts between a cooperative and its members. Under Options A and C, financially binding Day-Ahead Schedules must be submitted for service of load under the GFA, and the contracts are subject to loss and congestion charges; however, Option C contracts are eligible for an allocation of ARRs. (Option B is not available for new Midwest ISO members.) All GFAs are exempt from costs allocated throughout the Midwest ISO for certain high voltage transmission upgrades.

Big Rivers intends to request that the Midwest ISO grant all of its wholesale supply contracts GFA status. Such status is contingent on FERC approval.

Q. Can you describe the transmission assets to be transferred to the functional control of the Midwest ISO?

A. Big Rivers' current open access transmission tariff includes the entire Big Rivers transmission system including all facilities operating at 69 kV, 138 kV, 161 kV, and 345 kV. Big Rivers will relinquish functional control for all transmission facilities covered by its open access transmission tariff. Big Rivers still retains operational control of its transmission facilities after joining the Midwest ISO.

Q. Does Big Rivers currently have sufficient employees to handle the responsibilities associated with the process of Big Rivers' integration into the Midwest ISO?

A. I believe that Big Rivers currently has sufficient employees to accomplish the tasks that it will need to undertake during the integration period. Accordingly, Big Rivers does not plan at this time to add additional employees to its staff to handle the tasks I have identified above.

Q. Does Big Rivers plan to use outside consultants to accomplish the tasks you have described during the integration process?

A. No. At this time Big Rivers does not plan to use outside consultants, other than APM, to assist in accomplishing the tasks required for Big Rivers to achieve full integration with the Midwest ISO.

V. BIG RIVERS' ONGOING INVESTIGATION OF ALTERNATIVES

Q. Is Big Rivers continuing to investigate alternatives to membership in the Midwest ISO as potential solutions to the contingency reserve issue?

A. Yes. Big Rivers has informed the Midwest ISO that while the integration process is going forward, Big Rivers will continue to explore alternative arrangements that might serve as a solution for the Contingency Reserve issue. Big Rivers continues to work with TVA on the studies needed that would allow TVA to provide the 100 MWs of transmission service which is needed to provide a path to the existing SPP Reserve Sharing Group and that would, if available to Big Rivers, allow Big Rivers to become a partial participant in that group. Big Rivers also continues to work with SIPC to see if an arrangement to purchase Contingency Reserve supplied from their two 75 MW combustion turbines can be achieved. Big Rivers continues to work with the two aluminum smelters to see if an arrangement to provide 200 MWs of interruptible load can be achieved, which would serve to assist in satisfying Big Rivers' Contingency Reserve requirement. Big Rivers is absolutely committed to finding the least cost solution to the reserve issue that is actually feasible. As discussed by Mr. Luciani in his testimony, however, joining the Midwest ISO is the only solution that appears to be currently available to Big Rivers at a reasonable cost. Of course, Big Rivers is continuing to perform its due diligence with respect to issues involving the Midwest ISO.

Q. What analyses has Big Rivers performed in evaluating the alternative solutions you describe?

A. The cost/benefit analysis that has been prepared by Charles River Associates, and that is presented by Mr. Luciani in his testimony, Exhibit 4, represents an economic comparison of the alternative solutions to the Contingency Reserve issue available to Big Rivers in order to confirm whether or not membership in the Midwest ISO is the least cost solution.

Q. Will the alternative involving the smelters satisfy Big Rivers' contingency reserve obligations over the long term?

A. No. The arrangement with the smelters that is being pursued cannot be viewed as a permanent solution to the Contingency Reserve issue because Big Rivers cannot be confident that the smelters will commit to the arrangement for a lengthy period of time. In addition, this solution is dependent upon both smelters remaining in operation. Solving the Contingency Reserve requirement using smelter interruptibility would only be a temporary measure employed until a more reliable solution could be identified and implemented.

VI. IMPLICATIONS TO BIG RIVERS SHOULD THE COMMISSION DENY, OR FAIL TO ACT PROMPTLY ON, BIG RIVERS' APPLICATION

Q. If the Commission were to deny Big Rivers' application for approval to join the Midwest ISO, how would Big Rivers be able to satisfy its contingency reserve obligation?

A. Unless Big Rivers is able to establish an agreement to purchase Contingency Reserve from a source other than the Midwest ISO, a result that Big Rivers believes to be unlikely, Big Rivers will be required to self supply all of the Contingency Reserve necessary for it to meet the NERC reliability standard. In order to accomplish this, Big Rivers would likely have to reduce the generation of the Wilson unit well below its 417 MW rating. Big Rivers would have to hold Contingency Reserve, including spinning reserve on the remaining system generating units plus the quick-start capacity reserve on its combustion turbine, in the same amount as that reduced output level of the Wilson unit in order to be able to recover from the loss of the Wilson unit. As described by Mr. Luciani in his testimony, the significant economic impact of this self supply option would be felt in increased dependence on outside sources of power to serve Big Rivers' load on a daily basis.

Q. If the Commission were to deny Big Rivers' application, what would be the consequences for Big Rivers under the existing arrangements between Big Rivers and the Midwest ISO?

A. Pursuant to the MOU, if Big Rivers should decline to complete the integration process, it must repay the Midwest ISO its legal and staff costs incurred on behalf of the cancelled integration. Denial by the Commission of Big Rivers' application to join the Midwest ISO would not trigger the provision of the Memorandum of Understanding requiring Big Rivers to reimburse the Midwest ISO for the legal and staff costs described therein. Such denial would, however, trigger the termination of Big Rivers' Reserve Services Agreement with the Midwest ISO, and Big Rivers would be forced to immediately implement alternative arrangements to satisfy its Contingency Reserve requirements.

Q. Is there a timeline for achieving integration with the Midwest ISO by the proposed September 1, 2010 integration date?

A. Yes. A copy of this timeline is attached to my testimony as Exhibit DGC-3. It shows the various deadlines and milestones for Big Rivers to achieve integration with the Midwest ISO by September 1, 2010.

Q. Is there a date by which the Commission will need to act in order to achieve the September 1, 2010 integration date?

A. Yes. The Midwest ISO has informed Big Rivers that it must incorporate Big Rivers into its modeling by August 1, 2010 in order for Big Rivers to achieve integration by September 1, 2010. If the Commission does not approve the application prior to August 1, 2010, the Midwest ISO would not be able to incorporate Big Rivers into its modeling until November 1, 2010, and thus Big Rivers would not be able to integrate with the Midwest ISO until December 1, 2010, at the earliest.

Q. What risks and costs will Big Rivers face should the Commission fail to approve Big Rivers' application prior to August 1, 2010?

A. The primary risk that Big Rivers would confront in the event that integration with the Midwest ISO is delayed beyond September 1, 2010 is the risk of uncertainty regarding its ability to meet its Contingency Reserve obligations. As I have explained, Big Rivers' reserve service arrangement under the

Midwest ISO's Attachment RR expires on September 30, 2010. The Midwest ISO has stated that it would be willing to ask FERC to extend the term of this arrangement with Big Rivers if the necessary regulatory approvals are delayed, but this would require a filing with FERC to amend the Midwest ISO tariff. It may be more likely than not that such a filing would be accepted by FERC, but there is no certainty that it would be, and there could be a delay in the approval process as well. Thus, Big Rivers would face the risk that it would be left without a Contingency Reserve solution on October 1, 2010.

In addition, Big Rivers' current arrangement with TVA for Reliability Coordinator services will expire at the end of September 2010. If Big Rivers has not integrated with the Midwest ISO by that time, Big Rivers would be required to renew its Reliability Coordinator arrangement with TVA for another year, and it is required to pay up front for that arrangement. Big Rivers recently paid TVA $167,214 for Reliability Coordinator services for the period October 1, 2009-September 30, 2010, and would be required to pay a similar amount (which likely would escalate by 2-3% based on historical TVA practice) to renew the arrangement. Big Rivers would not be able to recoup any portion of this amount from TVA in the event that it integrates with the Midwest ISO during the annual period of that arrangement. If Big Rivers is forced to switch to the Midwest ISO for Reliability Coordinator services prior to full integration, it will incur approximately $700,000 in costs annually for Reliability Coordinator services to be provided by the Midwest ISO.

Q. Does this conclude your testimony at this time?

A. Yes.

VERIFICATION

I verify, state, and affirm that my testimony filed with this verification is true and accurate to the best of my knowledge, information, and belief.

David G. Crockett

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by David G. Crockett on this the 26th day of January, 2010.

Notary Public, Ky. State at Large
My Commission Expires 8-9-10

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

The newly approved terms are included in the shaded table rows below.

Glossary of Terms Used in Reliability Standards

Updated April 20, 2009

Term	Acronym	Definition
Adequacy		The ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
Adjacent Balancing Authority		A Balancing Authority Area that is interconnected another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.
Adverse Reliability Impact		The impact of an event that results in frequency-related instability; unplanned tripping of load or generation; or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection.
After the Fact	ATF	A time classification assigned to an RFI when the submittal time is greater than one hour after the start time of the RFI.
Agreement		A contract or arrangement, either written or verbal and sometimes enforceable by law.
Altitude Correction Factor		A multiplier applied to specify distances, which adjusts the distances to account for the change in relative air density (RAD) due to altitude from the RAD used to determine the specified distance. Altitude correction factors apply to both minimum worker approach distances and to minimum vegetation clearance distances.
Ancillary Service		Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Service Provider's transmission system in accordance with good utility practice. (*From FERC order 888-A.*)
Anti-Aliasing Filter		An analog filter installed at a metering point to remove the high frequency components of the signal over the AGC sample period.
Area Control Error	ACE	The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction for meter error.
Area Interchange Methodology		The Area Interchange methodology is characterized by determination of incremental transfer capability via simulation, from which Total Transfer Capability (TTC) can be mathematically derived. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from the TTC, and Postbacks and counterflows are added, to derive Available Transfer Capability. Under the Area Interchange Methodology, TTC results are generally reported on an area to area basis.
Arranged Interchange		The state where the Interchange Authority has received the Interchange information (initial or revised).

Term	Acronym	Definition
Automatic Generation Control	AGC	Equipment that automatically adjusts generation in a Balancing Authority Area from a central location to maintain the Balancing Authority's interchange schedule plus Frequency Bias. AGC may also accommodate automatic inadvertent payback and time error correction.
Available Flowgate Capability	AFC	A measure of the flow capability remaining on a Flowgate for further commercial activity over and above already committed uses. It is defined as TFC less Existing Transmission Commitments (ETC), less a Capacity Benefit Margin, less a Transmission Reliability Margin, plus Postbacks, and plus counterflows.
Available Transfer Capability	ATC	A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less Existing Transmission Commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin, plus Postbacks, plus counterflows.
Available Transfer Capability Implementation Document	ATCID	A document that describes the implementation of a methodology for calculating ATC or AFC, and provides information related to a Transmission Service Provider's calculation of ATC or AFC.
ATC Path		Any combination of Point of Receipt and Point of Delivery for which ATC is calculated; and any Posted Path[1].
Balancing Authority	BA	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.
Balancing Authority Area		The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.
Base Load		The minimum amount of electric power delivered or required over a given period at a constant rate.
Blackstart Capability Plan		A documented procedure for a generating unit or station to go from a shutdown condition to an operating condition delivering electric power without assistance from the electric system. This procedure is only a portion of an overall system restoration plan.
Block Dispatch		A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, the capacity of a given generator is segmented into loadable "blocks," each of which is grouped and ordered relative to other blocks (based on characteristics including, but not limited to, efficiency, run of river or fuel supply considerations, and/or "must-run" status).

[1] See 18 CFR 37.6(b)(1)

Glossary of Terms Used in Reliability Standards

Term	Acronym	Definition
Bulk Electric System		As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.
Burden		Operation of the Bulk Electric System that violates or is expected to violate a System Operating Limit or Interconnection Reliability Operating Limit in the Interconnection, or that violates any other NERC, Regional Reliability Organization, or local operating reliability standards or criteria.
Business Practices		Those business rules contained in the Transmission Service Provider's applicable tariff, rules, or procedures; associated Regional Reliability Organization or regional entity business practices; or NAESB Business Practices.
Capacity Benefit Margin	CBM	The amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs), whose loads are located on that Transmission Service Provider's system, to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.
Capacity Benefit Margin Implementation Document	CBMID	A document that describes the implementation of a Capacity Benefit Margin methodology.
Capacity Emergency		A capacity emergency exists when a Balancing Authority Area's operating capacity, plus firm purchases from other systems, to the extent available or limited by transfer capability, is inadequate to meet its demand plus its regulating requirements.
Cascading		The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.

Term	Acronym	Definition
Cascading Outages **NOTE: On December 27, 2007, the Federal Energy Regulatory Commission remanded the definition of "Cascading Outage" to NERC. On February 12, 2008, the NERC Board of Trustees withdrew its November 1, 2006 approval of that definition, without prejudice to the ongoing work of the FAC standards drafting team and the revised standards that are developed through the standards development process. Therefore, the definition is no longer in effect.**		The uncontrolled successive loss of Bulk Electric System Facilities triggered by an incident (or condition) at any location resulting in the interruption of electric service that cannot be restrained from spreading beyond a pre-determined area.
Clock Hour		The 60-minute period ending at :00. All surveys, measurements, and reports are based on Clock Hour periods unless specifically noted.
Cogeneration		Production of electricity from steam, heat, or other forms of energy produced as a by-product of another process.
Compliance Monitor		The entity that monitors, reviews, and ensures compliance of responsible entities with reliability standards.
Confirmed Interchange		The state where the Interchange Authority has verified the Arranged Interchange.
Congestion Management Report		A report that the Interchange Distribution Calculator issues when a Reliability Coordinator initiates the Transmission Loading Relief procedure. This report identifies the transactions and native and network load curtailments that must be initiated to achieve the loading relief requested by the initiating Reliability Coordinator.
Constrained Facility		A transmission facility (line, transformer, breaker, etc.) that is approaching, is at, or is beyond its System Operating Limit or Interconnection Reliability Operating Limit.
Contingency		The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.
Contingency Reserve		The provision of capacity deployed by the Balancing Authority to meet the Disturbance Control Standard (DCS) and other NERC and Regional Reliability Organization contingency requirements.
Contract Path		An agreed upon electrical path for the continuous flow of electrical power between the parties of an Interchange Transaction.

Glossary of Terms Used in Reliability Standards

Term	Acronym	Definition
Control Performance Standard	CPS	The reliability standard that sets the limits of a Balancing Authority's Area Control Error over a specified time period.
Corrective Action Plan		A list of actions and an associated timetable for implementation to remedy a specific problem.
Cranking Path		A portion of the electric system that can be isolated and then energized to deliver electric power from a generation source to enable the startup of one or more other generating units.
Critical Assets		Facilities, systems, and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the Bulk Electric System.
Critical Cyber Assets		Cyber Assets essential to the reliable operation of Critical Assets.
Curtailment		A reduction in the scheduled capacity or energy delivery of an Interchange Transaction.
Curtailment Threshold		The minimum Transfer Distribution Factor which, if exceeded, will subject an Interchange Transaction to curtailment to relieve a transmission facility constraint.
Cyber Assets		Programmable electronic devices and communication networks including hardware, software, and data.
Cyber Security Incident		Any malicious act or suspicious event that: • Compromises, or was an attempt to compromise, the Electronic Security Perimeter or Physical Security Perimeter of a Critical Cyber Asset, or, • Disrupts, or was an attempt to disrupt, the operation of a Critical Cyber Asset.
Delayed Fault Clearing		Fault clearing consistent with correct operation of a breaker failure protection system and its associated breakers, or of a backup protection system with an intentional time delay.
Demand		1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer.
Demand-Side Management	DSM	The term for all activities or programs undertaken by Load-Serving Entity or its customers to influence the amount or timing of electricity they use.
Direct Control Load Management	DCLM	Demand-Side Management that is under the direct control of the system operator. DCLM may control the electric supply to individual appliances or equipment on customer premises. DCLM as defined here does not include Interruptible Demand.

Term	Acronym	Definition
Dispatch Order		A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, each generator is ranked by priority.
Dispersed Load by Substations		Substation load information configured to represent a system for power flow or system dynamics modeling purposes, or both.
Distribution Factor	DF	The portion of an Interchange Transaction, typically expressed in per unit that flows across a transmission facility (Flowgate).
Distribution Provider		Provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage.
Disturbance		1. An unplanned event that produces an abnormal system condition. 2. Any perturbation to the electric system. 3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load.
Disturbance Control Standard	DCS	The reliability standard that sets the time limit following a Disturbance within which a Balancing Authority must return its Area Control Error to within a specified range.
Disturbance Monitoring Equipment	DME	Devices capable of monitoring and recording system data pertaining to a Disturbance. Such devices include the following categories of recorders[2]: • Sequence of event recorders which record equipment response to the event • Fault recorders, which record actual waveform data replicating the system primary voltages and currents. This may include protective relays. • Dynamic Disturbance Recorders (DDRs), which record incidents that portray power system behavior during dynamic events such as low-frequency (0.1 Hz – 3 Hz) oscillations and abnormal frequency or voltage excursions
Dynamic Interchange Schedule or Dynamic Schedule		A telemetered reading or value that is updated in real time and used as a schedule in the AGC/ACE equation and the integrated value of which is treated as a schedule for interchange accounting purposes. Commonly used for scheduling jointly owned generation to or from another Balancing Authority Area.

[2] Phasor Measurement Units and any other equipment that meets the functional requirements of DMEs may qualify as DMEs.

Term	Acronym	Definition
Dynamic Transfer		The provision of the real-time monitoring, telemetering, computer software, hardware, communications, engineering, energy accounting (including inadvertent interchange), and administration required to electronically move all or a portion of the real energy services associated with a generator or load out of one Balancing Authority Area into another.
Economic Dispatch		The allocation of demand to individual generating units on line to effect the most economical production of electricity.
Electrical Energy		The generation or use of electric power by a device over a period of time, expressed in kilowatthours (kWh), megawatthours (MWh), or gigawatthours (GWh).
Electronic Security Perimeter		The logical border surrounding a network to which Critical Cyber Assets are connected and for which access is controlled.
Element		Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components.
Emergency or BES Emergency		Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System.
Emergency Rating		The rating as defined by the equipment owner that specifies the level of electrical loading or output, usually expressed in megawatts (MW) or Mvar or other appropriate units, that a system, facility, or element can support, produce, or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.
Emergency RFI		Request for Interchange to be initiated for Emergency or Energy Emergency conditions.
Energy Emergency		A condition when a Load-Serving Entity has exhausted all other options and can no longer provide its customers' expected energy requirements.
Equipment Rating		The maximum and minimum voltage, current, frequency, real and reactive power flows on individual equipment under steady state, short-circuit and transient conditions, as permitted or assigned by the equipment owner.
Existing Transmission Commitments	ETC	Committed uses of a Transmission Service Provider's Transmission system considered when determining ATC or AFC.
Facility		A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)

Glossary of Terms Used in Reliability Standards

Term	Acronym	Definition
Facility Rating		The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.
Fault		An event occurring on an electric system such as a short circuit, a broken wire, or an intermittent connection.
Fire Risk		The likelihood that a fire will ignite or spread in a particular geographic area.
Firm Demand		That portion of the Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions.
Firm Transmission Service		The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption.
Flashover		An electrical discharge through air around or over the surface of insulation, between objects of different potential, caused by placing a voltage across the air space that results in the ionization of the air space.
Flowgate		1.) A portion of the Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions. 2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System.
Flowgate Methodology		The Flowgate methodology is characterized by identification of key Facilities as Flowgates. Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits. The impacts of Existing Transmission Commitments (ETCs) are determined by simulation. The impacts of ETC, Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM) are subtracted from the Total Flowgate Capability, and Postbacks and counterflows are added, to determine the Available Flowgate Capability (AFC) value for that Flowgate. AFCs can be used to determine Available Transfer Capability (ATC).
Forced Outage		1. The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons. 2. The condition in which the equipment is unavailable due to unanticipated failure.
Frequency Bias		A value, usually expressed in megawatts per 0.1 Hertz (MW/0.1 Hz), associated with a Balancing Authority Area that approximates the Balancing Authority Area's response to Interconnection frequency error.

Term	Acronym	Definition
Frequency Bias Setting		A value, usually expressed in MW/0.1 Hz, set into a Balancing Authority ACE algorithm that allows the Balancing Authority to contribute its frequency response to the Interconnection.
Frequency Deviation		A change in Interconnection frequency.
Frequency Error		The difference between the actual and scheduled frequency. ($F_A - F_S$)
Frequency Regulation		The ability of a Balancing Authority to help the Interconnection maintain Scheduled Frequency. This assistance can include both turbine governor response and Automatic Generation Control.
Frequency Response		(Equipment) The ability of a system or elements of the system to react or respond to a change in system frequency. (System) The sum of the change in demand, plus the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 Hertz (MW/0.1 Hz).
Generator Operator		The entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services.
Generator Owner		Entity that owns and maintains generating units.
Generator Shift Factor	GSF	A factor to be applied to a generator's expected change in output to determine the amount of flow contribution that change in output will impose on an identified transmission facility or Flowgate.
Generator-to-Load Distribution Factor	GLDF	The algebraic sum of a Generator Shift Factor and a Load Shift Factor to determine the total impact of an Interchange Transaction on an identified transmission facility or Flowgate.
Generation Capability Import Requirement	GCIR	The amount of generation capability from external sources identified by a Load-Serving Entity (LSE) or Resource Planner (RP) to meet its generation reliability or resource adequacy requirements as an alternative to internal resources.
Host Balancing Authority		1. A Balancing Authority that confirms and implements Interchange Transactions for a Purchasing Selling Entity that operates generation or serves customers directly within the Balancing Authority's metered boundaries. 2. The Balancing Authority within whose metered boundaries a jointly owned unit is physically located.
Hourly Value		Data measured on a Clock Hour basis.
Implemented Interchange		The state where the Balancing Authority enters the Confirmed Interchange into its Area Control Error equation.
Inadvertent Interchange		The difference between the Balancing Authority's Net Actual Interchange and Net Scheduled Interchange. ($I_A - I_S$)

Term	Acronym	Definition
Independent Power Producer	IPP	Any entity that owns or operates an electricity generating facility that is not included in an electric utility's rate base. This term includes, but is not limited to, cogenerators and small power producers and all other nonutility electricity producers, such as exempt wholesale generators, who sell electricity.
Institute of Electrical and Electronics Engineers, Inc.	IEEE	
Interchange Distribution Calculator	IDC	The mechanism used by Reliability Coordinators in the Eastern Interconnection to calculate the distribution of Interchange Transactions over specific Flowgates. It includes a database of all Interchange Transactions and a matrix of the Distribution Factors for the Eastern Interconnection.
Interchange		Energy transfers that cross Balancing Authority boundaries.
Interchange Authority		The responsible entity that authorizes implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.
Interchange Schedule		An agreed-upon Interchange Transaction size (megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of power and energy between the Source and Sink Balancing Authorities involved in the transaction.
Interchange Transaction		An agreement to transfer energy from a seller to a buyer that crosses one or more Balancing Authority Area boundaries.
Interchange Transaction Tag or Tag		The details of an Interchange Transaction required for its physical implementation.
Interconnected Operations Service		A service (exclusive of basic energy and transmission services) that is required to support the reliable operation of interconnected Bulk Electric Systems.
Interconnection		When capitalized, any one of the three major electric system networks in North America: Eastern, Western, and ERCOT.
Interconnection Reliability Operating Limit	IROL	A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading Outages that adversely impact the reliability of the Bulk Electric System.
Interconnection Reliability Operating Limit T_v	IROL T_v	The maximum time that an Interconnection Reliability Operating Limit can be violated before the risk to the interconnection or other Reliability Coordinator Area(s) becomes greater than acceptable. Each Interconnection Reliability Operating Limit's T_v shall be less than or equal to 30 minutes.

Glossary of Terms Used in Reliability Standards

Term	Acronym	Definition
Intermediate Balancing Authority		A Balancing Authority Area that has connecting facilities in the Scheduling Path between the Sending Balancing Authority Area and Receiving Balancing Authority Area and operating agreements that establish the conditions for the use of such facilities
Interruptible Load or Interruptible Demand		Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment.
Joint Control		Automatic Generation Control of jointly owned units by two or more Balancing Authorities.
Limiting Element		The element that is 1.)Either operating at its appropriate rating, or 2,) Would be following the limiting contingency. Thus, the Limiting Element establishes a system limit.
Load		An end-use device or customer that receives power from the electric system.
Load Shift Factor	LSF	A factor to be applied to a load's expected change in demand to determine the amount of flow contribution that change in demand will impose on an identified transmission facility or monitored Flowgate.
Load-Serving Entity		Secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.
Misoperation		▪ Any failure of a Protection System element to operate within the specified time when a fault or abnormal condition occurs within a zone of protection. ▪ Any operation for a fault not within a zone of protection (other than operation as backup protection for a fault in an adjacent zone that is not cleared within a specified time for the protection for that zone). ▪ Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity.
Native Load		The end-use customers that the Load-Serving Entity is obligated to serve.
Net Actual Interchange		The algebraic sum of all metered interchange over all interconnections between two physically Adjacent Balancing Authority Areas.
Net Energy for Load		Net Balancing Authority Area generation, plus energy received from other Balancing Authority Areas, less energy delivered to Balancing Authority Areas through interchange. It includes Balancing Authority Area losses but excludes energy required for storage at energy storage facilities.

Glossary of Terms Used in Reliability Standards

Term	Acronym	Definition
Net Interchange Schedule		The algebraic sum of all Interchange Schedules with each Adjacent Balancing Authority.
Net Scheduled Interchange		The algebraic sum of all Interchange Schedules across a given path or between Balancing Authorities for a given period or instant in time.
Network Integration Transmission Service		Service that allows an electric transmission customer to integrate, plan, economically dispatch and regulate its network reserves in a manner comparable to that in which the Transmission Owner serves Native Load customers.
Non-Firm Transmission Service		Transmission service that is reserved on an as-available basis and is subject to curtailment or interruption.
Non-Spinning Reserve		1. That generating reserve not connected to the system but capable of serving demand within a specified time. 2. Interruptible load that can be removed from the system in a specified time.
Normal Clearing		A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems.
Normal Rating		The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or element can support or withstand through the daily demand cycles without loss of equipment life.
Nuclear Plant Generator Operator		Any Generator Operator or Generator Owner that is a Nuclear Plant Licensee responsible for operation of a nuclear facility licensed to produce commercial power.
Nuclear Plant Off-site Power Supply (Off-site Power)		The electric power supply provided from the electric system to the nuclear power plant distribution system as required per the nuclear power plant license.
Nuclear Plant Licensing Requirements (NPLRs)		Requirements included in the design basis of the nuclear plant and statutorily mandated for the operation of the plant, including nuclear power plant licensing requirements for: 1) Off-site power supply to enable safe shutdown of the plant during an electric system or plant event; and 2) Avoiding preventable challenges to nuclear safety as a result of an electric system disturbance, transient, or condition.
Nuclear Plant Interface Requirements (NPIRs)		The requirements based on NPLRs and Bulk Electric System requirements that have been mutually agreed to by the Nuclear Plant Generator Operator and the applicable Transmission Entities.
Off-Peak		Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of lower electrical demand.

Term	Acronym	Definition
On-Peak		Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of higher electrical demand.
Open Access Same Time Information Service	OASIS	An electronic posting system that the Transmission Service Provider maintains for transmission access data and that allows all transmission customers to view the data simultaneously.
Open Access Transmission Tariff	OATT	Electronic transmission tariff accepted by the U.S. Federal Energy Regulatory Commission requiring the Transmission Service Provider to furnish to all shippers with non-discriminating service comparable to that provided by Transmission Owners to themselves.
Operating Plan		A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan.
Operating Procedure		A document that identifies specific steps or tasks that should be taken by one or more specific operating positions to achieve specific operating goal(s). The steps in an Operating Procedure should be followed in the order in which they are presented, and should be performed by the position(s) identified. A document that lists the specific steps for a system operator to take in removing a specific transmission line from service is an example of an Operating Procedure.
Operating Process		A document that identifies general steps for achieving a generic operating goal. An Operating Process includes steps with options that may be selected depending upon Real-time conditions. A guideline for controlling high voltage is an example of an Operating Process.
Operating Reserve		That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserve.
Operating Reserve – Spinning		The portion of Operating Reserve consisting of: • Generation synchronized to the system and fully available to serve load within the Disturbance Recovery Period following the contingency event; or • Load fully removable from the system within the Disturbance Recovery Period following the contingency event.
Operating Reserve – Supplemental		The portion of Operating Reserve consisting of: • Generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within the Disturbance Recovery Period following the contingency event; or • Load fully removable from the system within the Disturbance Recovery Period following the contingency event.

Term	Acronym	Definition
Operating Voltage		The voltage level by which an electrical system is designated and to which certain operating characteristics of the system are related; also, the effective (root-mean-square) potential difference between any two conductors or between a conductor and the ground. The actual voltage of the circuit may vary somewhat above or below this value.
Operational Planning Analysis		An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).
Outage Transfer Distribution Factor	OTDF	In the post-contingency configuration of a system under study, the electric Power Transfer Distribution Factor (PTDF) with one or more system Facilities removed from service (outaged).
Overlap Regulation Service		A method of providing regulation service in which the Balancing Authority providing the regulation service incorporates another Balancing Authority's actual interchange, frequency response, and schedules into providing Balancing Authority's AGC/ACE equation.
Participation Factors		A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, generators are assigned a percentage that they will contribute to serve load.
Peak Demand		1. The highest hourly integrated Net Energy For Load within a Balancing Authority Area occurring within a given period (e.g., day, month, season, or year). 2. The highest instantaneous demand within the Balancing Authority Area.
Performance-Reset Period		The time period that the entity being assessed must operate without any violations to reset the level of non compliance to zero.
Physical Security Perimeter		The physical, completely enclosed ("six-wall") border surrounding computer rooms, telecommunications rooms, operations centers, and other locations in which Critical Cyber Assets are housed and for which access is controlled.
Planning Authority		The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.
Planning Coordinator		See Planning Authority.
Point of Delivery	POD	A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction leaves or a Load-Serving Entity receives its energy.

Term	Acronym	Definition
Point of Receipt	POR	A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction enters or a Generator delivers its output.
Point to Point Transmission Service	PTP	The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery.
Postback		Positive adjustments to ATC or AFC as defined in Business Practices. Such Business Practices may include processing of redirects and unscheduled service.
Power Transfer Distribution Factor	PTDF	In the pre-contingency configuration of a system under study, a measure of the responsiveness or change in electrical loadings on transmission system Facilities due to a change in electric power transfer from one area to another, expressed in percent (up to 100%) of the change in power transfer
Pro Forma Tariff		Usually refers to the standard OATT and/or associated transmission rights mandated by the U.S. Federal Energy Regulatory Commission Order No. 888.
Protection System		Protective relays, associated communication systems, voltage and current sensing devices, station batteries and DC control circuitry.
Pseudo-Tie		A telemetered reading or value that is updated in real time and used as a "virtual" tie line flow in the AGC/ACE equation but for which no physical tie or energy metering actually exists. The integrated value is used as a metered MWh value for interchange accounting purposes.
Purchasing-Selling Entity		The entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.
Ramp Rate or Ramp		(Schedule) The rate, expressed in megawatts per minute, at which the interchange schedule is attained during the ramp period. (Generator) The rate, expressed in megawatts per minute, that a generator changes its output.
Rated Electrical Operating Conditions		The specified or reasonably anticipated conditions under which the electrical system or an individual electrical circuit is intend/designed to operate
Rating		The operational limits of a transmission system element under a set of specified conditions.
Rated System Path Methodology		The Rated System Path Methodology is characterized by an initial Total Transfer Capability (TTC), determined via simulation. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from TTC, and Postbacks and counterflows are added as applicable, to derive Available Transfer Capability. Under the Rated System Path Methodology, TTC results are generally reported as specific transmission path capabilities.

Term	Acronym	Definition
Reactive Power		The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kvar) or megavars (Mvar).
Real Power		The portion of electricity that supplies energy to the load.
Reallocation		The total or partial curtailment of Transactions during TLR Level 3a or 5a to allow Transactions using higher priority to be implemented.
Real-time		Present time as opposed to future time. (From Interconnection Reliability Operating Limits standard.)
Real-time Assessment		An examination of existing and expected system conditions, conducted by collecting and reviewing immediately available data
Receiving Balancing Authority		The Balancing Authority importing the Interchange.
Regional Reliability Organization		1. An entity that ensures that a defined area of the Bulk Electric System is reliable, adequate and secure. 2. A member of the North American Electric Reliability Council. The Regional Reliability Organization can serve as the Compliance Monitor.
Regional Reliability Plan		The plan that specifies the Reliability Coordinators and Balancing Authorities within the Regional Reliability Organization, and explains how reliability coordination will be accomplished.
Regulating Reserve		An amount of reserve responsive to Automatic Generation Control, which is sufficient to provide normal regulating margin.
Regulation Service		The process whereby one Balancing Authority contracts to provide corrective response to all or a portion of the ACE of another Balancing Authority. The Balancing Authority providing the response assumes the obligation of meeting all applicable control criteria as specified by NERC for itself and the Balancing Authority for which it is providing the Regulation Service.
Reliability Adjustment RFI		Request to modify an Implemented Interchange Schedule for reliability purposes.

Term	Acronym	Definition
Reliability Coordinator		The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.
Reliability Coordinator Area		The collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas.
Reliability Coordinator Information System	RCIS	The system that Reliability Coordinators use to post messages and share operating information in real time.
Remedial Action Scheme	RAS	See "Special Protection System"
Reportable Disturbance		Any event that causes an ACE change greater than or equal to 80% of a Balancing Authority's or reserve sharing group's most severe contingency. The definition of a reportable disturbance is specified by each Regional Reliability Organization. This definition may not be retroactively adjusted in response to observed performance.
Reserve Sharing Group		A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker (e.g., between zero and ten minutes) then, for the purposes of Disturbance Control Performance, the Areas become a Reserve Sharing Group.
Resource Planner		The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority Area.
Response Rate		The Ramp Rate that a generating unit can achieve under normal operating conditions expressed in megawatts per minute (MW/Min).
Request for Interchange	RFI	A collection of data as defined in the NAESB RFI Datasheet, to be submitted to the Interchange Authority for the purpose of implementing bilateral Interchange between a Source and Sink Balancing Authority.
Right-of-Way (ROW)		A corridor of land on which electric lines may be located. The Transmission Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.
Scenario		Possible event.

Term	Acronym	Definition
Schedule		(Verb) To set up a plan or arrangement for an Interchange Transaction. (Noun) An Interchange Schedule.
Scheduled Frequency		60.0 Hertz, except during a time correction.
Scheduling Entity		An entity responsible for approving and implementing Interchange Schedules.
Scheduling Path		The Transmission Service arrangements reserved by the Purchasing-Selling Entity for a Transaction.
Sending Balancing Authority		The Balancing Authority exporting the Interchange.
Sink Balancing Authority		The Balancing Authority in which the load (sink) is located for an Interchange Transaction. (This will also be a Receiving Balancing Authority for the resulting Interchange Schedule.)
Source Balancing Authority		The Balancing Authority in which the generation (source) is located for an Interchange Transaction. (This will also be a Sending Balancing Authority for the resulting Interchange Schedule.)
Special Protection System (Remedial Action Scheme)		An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.
Spinning Reserve		Unloaded generation that is synchronized and ready to serve additional demand.
Stability		The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances.
Stability Limit		The maximum power flow possible through some particular point in the system while maintaining stability in the entire system or the part of the system to which the stability limit refers.
Supervisory Control and Data Acquisition	SCADA	A system of remote control and telemetry used to monitor and control the transmission system.
Supplemental Regulation Service		A method of providing regulation service in which the Balancing Authority providing the regulation service receives a signal representing all or a portion of the other Balancing Authority's ACE.
Surge		A transient variation of current, voltage, or power flow in an electric circuit or across an electric system.

Term	Acronym	Definition
Sustained Outage		The deenergized condition of a transmission line resulting from a fault or disturbance following an unsuccessful automatic reclosing sequence and/or unsuccessful manual reclosing procedure.
System		A combination of generation, transmission, and distribution components.
System Operating Limit		The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to: • Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings) • Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits) • Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability) • System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)
System Operator		An individual at a control center (Balancing Authority, Transmission Operator, Generator Operator, Reliability Coordinator) whose responsibility it is to monitor and control that electric system in real time.
Telemetering		The process by which measurable electrical quantities from substations and generating stations are instantaneously transmitted to the control center, and by which operating commands from the control center are transmitted to the substations and generating stations.
Thermal Rating		The maximum amount of electrical current that a transmission line or electrical facility can conduct over a specified time period before it sustains permanent damage by overheating or before it sags to the point that it violates public safety requirements.
Tie Line		A circuit connecting two Balancing Authority Areas.
Tie Line Bias		A mode of Automatic Generation Control that allows the Balancing Authority to 1.) maintain its Interchange Schedule and 2.) respond to Interconnection frequency error.
Time Error		The difference between the Interconnection time measured at the Balancing Authority(ies) and the time specified by the National Institute of Standards and Technology. Time error is caused by the accumulation of Frequency Error over a given period.
Time Error Correction		An offset to the Interconnection's scheduled frequency to return the Interconnection's Time Error to a predetermined value.

Term	Acronym	Definition
TLR Log		Report required to be filed after every TLR Level 2 or higher in a specified format. The NERC IDC prepares the report for review by the issuing Reliability Coordinator. After approval by the issuing Reliability Coordinator, the report is electronically filed in a public area of the NERC Web site.
Total Flowgate Capability	TFC	The maximum flow capability on a Flowgate, is not to exceed its thermal rating, or in the case of a flowgate used to represent a specific operating constraint (such as a voltage or stability limit), is not to exceed the associated System Operating Limit.
Total Transfer Capability	TTC	The amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions.
Transaction		See Interchange Transaction.
Transfer Capability		The measure of the ability of interconnected electric systems to move or transfer power *in a reliable manner* from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). The transfer capability from "Area A" to "Area B" is *not* generally equal to the transfer capability from "Area B" to "Area A."
Transfer Distribution Factor		See Distribution Factor.
Transmission		An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.
Transmission Constraint		A limitation on one or more transmission elements that may be reached during normal or contingency system operations.
Transmission Customer		1. Any eligible customer (or its designated agent) that can or does execute a transmission service agreement or can or does receive transmission service. 2. Any of the following responsible entities: Generator Owner, Load-Serving Entity, or Purchasing-Selling Entity.
Transmission Line		A system of structures, wires, insulators and associated hardware that carry electric energy from one point to another in an electric power system. Lines are operated at relatively high voltages varying from 69 kV up to 765 kV, and are capable of transmitting large quantities of electricity over long distances.
Transmission Operator		The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission facilities.

Term	Acronym	Definition
Transmission Operator Area		The collection of Transmission assets over which the Transmission Operator is responsible for operating.
Transmission Owner		The entity that owns and maintains transmission facilities.
Transmission Planner		The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority Area.
Transmission Reliability Margin	TRM	The amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.
Transmission Reliability Margin Implementation Document	TRMID	A document that describes the implementation of a Transmission Reliability Margin methodology, and provides information related to a Transmission Operator's calculation of TRM.
Transmission Service		Services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.
Transmission Service Provider		The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.
Vegetation		All plant material, growing or not, living or dead.
Vegetation Inspection		The systematic examination of a transmission corridor to document vegetation conditions.
Wide Area		The entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits.

Introduction

1. **Title:** **Disturbance Control Performance**
2. **Number:** BAL-002-0
3. **Purpose:**

   The purpose of the Disturbance Control Standard (DCS) is to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance. Because generator failures are far more common than significant losses of load and because Contingency Reserve activation does not typically apply to the loss of load, the application of DCS is limited to the loss of supply and does not apply to the loss of load.
4. **Applicability:**
   - **4.1.** Balancing Authorities
   - **4.2.** Reserve Sharing Groups (Balancing Authorities may meet the requirements of Standard 002 through participation in a Reserve Sharing Group.)
   - **4.3.** Regional Reliability Organizations
5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources, or coordinated adjustments to Interchange Schedules.

R1.1. A Balancing Authority may elect to fulfill its Contingency Reserve obligations by participating as a member of a Reserve Sharing Group. In such cases, the Reserve Sharing Group shall have the same responsibilities and obligations as each Balancing Authority with respect to monitoring and meeting the requirements of Standard BAL-002.

R2. Each Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group shall specify its Contingency Reserve policies, including:

R2.1. The minimum reserve requirement for the group.

R2.2. Its allocation among members.

R2.3. The permissible mix of Operating Reserve – Spinning and Operating Reserve – Supplemental that may be included in Contingency Reserve.

R2.4. The procedure for applying Contingency Reserve in practice.

R2.5. The limitations, if any, upon the amount of interruptible load that may be included.

R2.6. The same portion of resource capacity (e.g. reserves from jointly owned generation) shall not be counted more than once as Contingency Reserve by multiple Balancing Authorities.

R3. Each Balancing Authority or Reserve Sharing Group shall activate sufficient Contingency Reserve to comply with the DCS.

R3.1. As a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency. All Balancing Authorities and Reserve Sharing Groups shall review, no less frequently than annually, their probable contingencies to determine their prospective most severe single contingencies.

R4. A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. The Disturbance Recovery Criterion is:

R4.1. A Balancing Authority shall return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE values just prior to the Disturbance, the Balancing Authority shall return ACE to its pre-Disturbance value.

R4.2. The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance. This period may be adjusted to better suit the needs of an Interconnection based on analysis approved by the NERC Operating Committee.

R5. Each Reserve Sharing Group shall comply with the DCS. A Reserve Sharing Group shall be considered in a Reportable Disturbance condition whenever a group member has experienced a Reportable Disturbance and calls for the activation of Contingency Reserves from one or more other group members. (If a group member has experienced a Reportable Disturbance but does not call for reserve activation from other members of the Reserve Sharing Group, then that member shall report as a single Balancing Authority.) Compliance may be demonstrated by either of the following two methods:

R5.1. The Reserve Sharing Group reviews group ACE (or equivalent) and demonstrates compliance to the DCS. To be in compliance, the group ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

or

R5.2. The Reserve Sharing Group reviews each member's ACE in response to the activation of reserves. To be in compliance, a member's ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

R6. A Balancing Authority or Reserve Sharing Group shall fully restore its Contingency Reserves within the Contingency Reserve Restoration Period for its Interconnection.

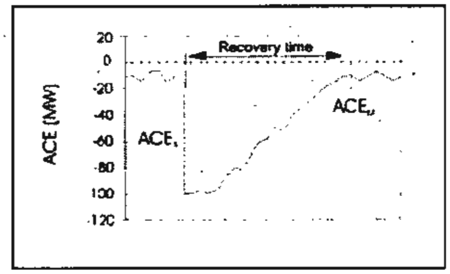
R6.1. The Contingency Reserve Restoration Period begins at the end of the Disturbance Recovery Period.

R6.2. The default Contingency Reserve Restoration Period is 90 minutes. This period may be adjusted to better suit the reliability targets of the Interconnection based on analysis approved by the NERC Operating Committee.

C. Measures

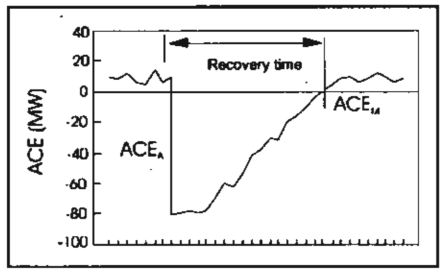
M1. A Balancing Authority or Reserve Sharing Group shall calculate and report compliance with the Disturbance Control Standard for all Disturbances greater than or equal to 80% of the magnitude of the Balancing Authority's or of the Reserve Sharing Group's most severe single contingency loss. Regions may, at their discretion, require a lower reporting threshold. Disturbance Control Standard is measured as the percentage recovery (R_i).

For loss of generation:



if $ACE_A < 0$
then

$$R_i = \frac{MW_{Loss} - \max(0, ACE_A - ACE_M)}{MW_{Loss}} * 100\%$$



if $ACE_A \geq 0$
then

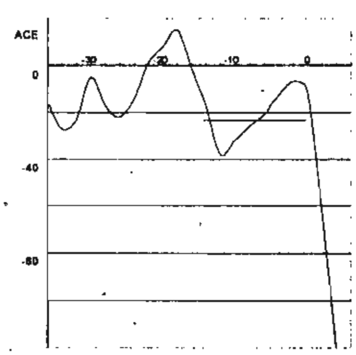
$$R_i = \frac{MW_{Loss} - \max(0, -ACE_M)}{MW_{Loss}} * 100\%$$

where:

- MW_{LOSS} is the MW size of the Disturbance as measured at the beginning of the loss,
- ACE_A is the pre-disturbance ACE,
- ACE_M is the maximum algebraic value of ACE measured within the fifteen minutes following the Disturbance. A Balancing Authority or Reserve Sharing Group may, at its discretion, set $ACE_M = ACE_{15\ min}$, and

The Balancing Authority or Reserve Sharing Group shall record the MW_{LOSS} value as measured at the site of the loss to the extent possible. The value should not be measured as a change in ACE since governor response and AGC response may introduce error.

The Balancing Authority or Reserve Sharing Group shall base the value for ACE_A on the average ACE over the period just prior to the start of the Disturbance (10 and 60 seconds prior and including at least 4 scans of ACE). In the illustration below, the horizontal line represents an averaging of ACE for 15 seconds prior to the start of the Disturbance with a result of ACE_A = - 25 MW.



The average percent recovery is the arithmetic average of all the calculated R_i's for Reportable Disturbances during a given quarter. Average percent recovery is similarly calculated for excludable Disturbances.

D. Compliance

1. Compliance Monitoring Process

Compliance with the DCS shall be measured on a percentage basis as set forth in the measures above.

Each Balancing Authority or Reserve Sharing Group shall submit one completed copy of DCS Form, "NERC Control Performance Standard Survey – All Interconnections" to its Resources Subcommittee Survey Contact no later than the 10th day following the end of the calendar quarter (i.e. April 10th, July 10th, October 10th, January 10th). The Regional Reliability Organization must submit a summary document reporting compliance with DCS to NERC no later than the 20th day of the month following the end of the quarter.

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

Compliance for DCS will be evaluated for each reporting period. Reset is one calendar quarter without a violation.

1.3. Data Retention

The data that support the calculation of DCS are to be retained in electronic form for at least a one-year period. If the DCS data for a Reserve Sharing Group and Balancing Area are undergoing a review to address a question that has been raised regarding the data, the data are to be saved beyond the normal retention period until the question is formally resolved.

1.4. Additional Compliance Information

Reportable Disturbances – Reportable Disturbances are contingencies that are greater than or equal to 80% of the most severe single Contingency. A Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group may optionally reduce the 80% threshold, provided that normal operating characteristics are not being considered or misrepresented as contingencies. Normal operating characteristics are excluded because DCS only measures the recovery from sudden, unanticipated losses of supply-side resources.

Simultaneous Contingencies – Multiple Contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the most severe single Contingency, the loss shall be reported, but excluded from compliance evaluation.

Multiple Contingencies within the Reportable Disturbance Period – Additional Contingencies that occur after one minute of the start of a Reportable Disturbance but before the end of the Disturbance Recovery Period can be excluded from evaluation. The Balancing Authority or Reserve Sharing Group shall determine the DCS compliance of the initial Reportable Disturbance by performing a reasonable estimation of the response that would have occurred had the second and subsequent contingencies not occurred.

Multiple Contingencies within the Contingency Reserve Restoration Period – Additional Reportable Disturbances that occur after the end of the Disturbance Recovery Period but before the end of the Contingency Reserve Restoration Period shall be reported and included in the compliance evaluation. However, the Balancing Authority or Reserve Sharing Group can request a waiver from the Resources Subcommittee for the event if the contingency reserves were rendered inadequate by prior contingencies and a good faith effort to replace contingency reserve can be shown.

2. **Levels of Non-Compliance**

Each Balancing Authority or Reserve Sharing Group not meeting the DCS during a given calendar quarter shall increase its Contingency Reserve obligation for the calendar quarter (offset by one month) following the evaluation by the NERC or Compliance Monitor [e.g. for the first calendar quarter of the year, the penalty is applied for May, June, and July.] The increase shall be directly proportional to the non-compliance with the DCS in the preceding quarter. This adjustment is not compounded across quarters, and is an additional percentage of reserve needed beyond the most severe single Contingency. A Reserve Sharing Group may choose an allocation method for increasing its Contingency Reserve for the Reserve Sharing Group provided that this increase is fully allocated.

A representative from each Balancing Authority or Reserve Sharing Group that was non-compliant in the calendar quarter most recently completed shall provide written documentation verifying that the Balancing Authority or Reserve Sharing Group will apply the appropriate DCS performance adjustment beginning the first day of the succeeding month, and will continue to apply it for three months. The written documentation shall accompany the quarterly Disturbance Control Standard Report when a Balancing Authority or Reserve Sharing Group is non-compliant.

2.1. **Level 1:** Value of the average percent recovery for the quarter is less than 100% but greater than or equal to 95%.

2.2. **Level 2:** Value of the average percent recovery for the quarter is less than 95% but greater than or equal to 90%.

2.3. **Level 3:** Value of average percent recovery for the quarter is less than 90% but greater than or equal to 85%.

2.4. **Level 4:** Value of average percent recovery for the quarter is less than 85%.

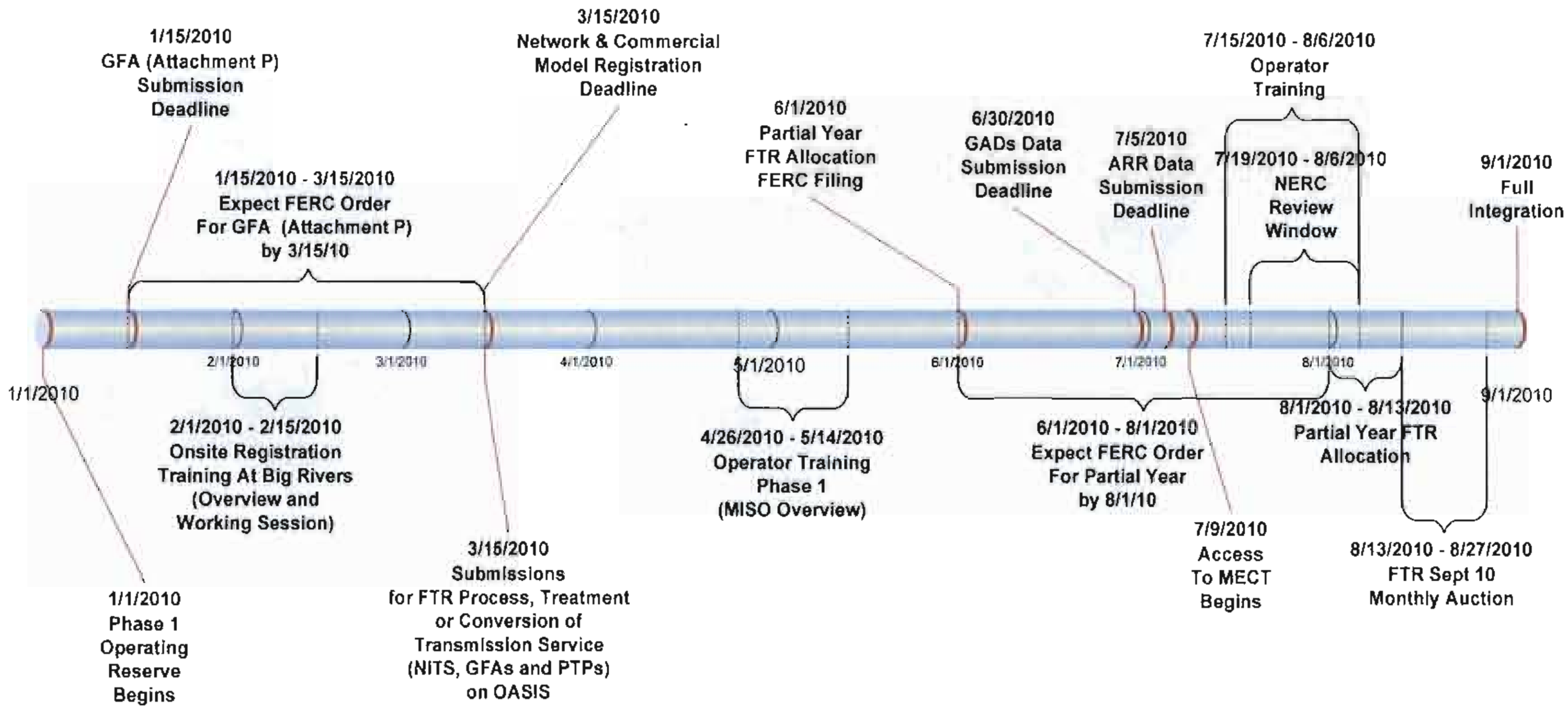
E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	February 14, 2006	Revised graph on page 3, "10 min." to "Recovery time." Removed fourth bullet.	Errata

Draft Timeline



MidwestISO
Energizing the Heartland

Exhibit DGC-3

COMMONWEALTH OF KENTUCKY
BEFORE THE
PUBLIC SERVICE COMMISSION OF KENTUCKY

Case No. 2010-00___

DIRECT TESTIMONY OF C. WILLIAM BLACKBURN

ON BEHALF OF
APPLICANTS

FEBRUARY 2010

DIRECT TESTIMONY OF
C. WILLIAM BLACKBURN

I. INTRODUCTION

Q. Please state your name, position, and qualifications.

A. My name is C. William Blackburn. I am employed by Big Rivers Electric Corporation ("Big Rivers") as its Senior Vice President Financial and Energy Services and Chief Financial Officer ("CFO"). I have held this position since February 2009. From November 2005 through February 2009, I held the position of Vice President Financial Services, CFO, and Interim Vice President Power Supply. Prior to serving as CFO, I held the position of Vice President Power Supply for 10 years. I have testified on behalf of Big Rivers many times before the Kentucky Public Service Commission ("KPSC" or the "Commission"), including for fuel hearings, environmental cases, rate cases, and transmission cases, as well as Big Rivers' application for approval of the unwind of the lease transaction with E.ON U.S., LLC ("E.ON") and its subsidiaries (the "Unwind Transaction"). Altogether I have been employed by Big Rivers for a total of 32 years.

Q. Please summarize the purpose of your testimony in these proceedings.

A. The purpose of my testimony is to address certain issues relating to Big Rivers' request for the Commission's approval to join the Midwest Independent Transmission System Operator ("Midwest ISO"). Specifically, I address the effect of Big Rivers becoming a Midwest ISO member on the level and cost of services now being provided by Big Rivers and other entities, including ACES Power Marketing LLC ("APM"). I also explain that joining the Midwest ISO will have no effect on the Big Rivers integrated resource plan ("IRP") process, and describe the current state of Big Rivers' IRP process. I then describe the ongoing costs that I anticipate Big Rivers will incur as a result of becoming a member of the Midwest ISO. Finally, I identify the creditor approvals that Big Rivers will require in order to become a Midwest ISO member, and outline the schedule for Big Rivers to obtain those approvals.

II. <u>EFFECT ON SERVICES OF BIG RIVERS MEMBERSHIP IN THE MIDWEST ISO</u>

Q. Do you anticipate that joining the Midwest ISO will result in any adverse impact on the right to use the transmission system to serve Big Rivers' members' load?

A. I do not anticipate Big Rivers' membership in the Midwest ISO will have any adverse impact on Big Rivers' rights to use its transmission system to provide service to its members' load. As I explain more fully later in my testimony, I believe that Big Rivers will incur some additional costs as a result of Midwest ISO membership, and Big Rivers would propose to recover these costs in a future rate adjustment filing. However, that rate adjustment filing would not be driven solely by the additional costs associated with Midwest ISO membership, which Big Rivers believes will not be substantial enough to require an immediate rate adjustment filing.

Q. What impact will Midwest ISO participation have if Big Rivers were to lose one or both of the smelters?

A. I believe that participation in the Midwest ISO will be advantageous to Big Rivers if it were ever to lose one or both of the smelters as customers. If such an event were to happen, Big Rivers would find itself with significant amounts of excess capacity. As a participant in the Midwest ISO's Energy and Ancillary Services Markets, Big Rivers would have the opportunity to bid such excess capacity into the markets and sell the output when market prices are financially attractive. Big Rivers would incur no additional transmission expense for such sales within the Midwest ISO (or into the PJM Interconnection, LLC ("PJM")), because there is no additional charge for transmission out of Big Rivers' system to a purchaser within either the Midwest ISO or PJM. Participation in the Midwest ISO would not preclude Big Rivers from exercising any options it would otherwise have to dispose of such excess capacity.

Q. Do you anticipate that there will be any impact on services provided by others to Big Rivers as a result of Big Rivers becoming a member of the Midwest ISO?

A. I believe that there will be some impact on the generation dispatch services that are provided to Big Rivers. LG&E Energy Marketing, Inc. currently provides full generation dispatch services to Big Rivers. However, Big Rivers is in the process of transitioning to APM, which already provides power marketing services to Big Rivers, to be the provider of generation dispatch services. That transition should be complete by the fall of 2010. Once Big Rivers becomes fully integrated with the Midwest ISO, it will no longer require full generation dispatch services from APM; however, Big Rivers may still require more limited generation dispatch services, such as coordination of unit availability, outages, ramping, and other unit specific characteristics, regulatory coordination, and other functions. Big Rivers has not yet determined whether to pursue such services from APM or any other entity.

III. EFFECT OF MIDWEST ISO MEMBERSHIP ON THE BIG RIVERS IRP PROCESS

Q. Please describe the current state of Big Rivers' IRP process.

A. Each electric utility under the Commission's jurisdiction is required to file an IRP with the Commission every three years. The plan provides historical and projected demand, resource and financial data, and other operating performance and system information. The plan must discuss the facts, assumptions, and conclusions upon which it is based, and any actions proposed by the utility as a result of the plan. The next Big Rivers IRP is due to be filed with the Commission no later than November 15, 2010.

Q. Will joining the Midwest ISO have any effect on Big Rivers' IRP process and the Commission's review of Big Rivers' IRPs?

A. I do not believe so. Big Rivers has been told, in discussions with the Midwest ISO and with GDS Associates, Inc., which performs integrated resource planning for Hoosier Energy Rural Electric Cooperative, Inc., a member of the Midwest ISO, that there is no change in the state IRP process that would result from Big Rivers becoming a member of the Midwest ISO. Membership in the Midwest ISO could affect the substantive content of the IRP, but would not impact the process itself or the Commission's jurisdiction over that process.

IV. ONGOING COSTS TO BIG RIVERS OF MIDWEST ISO MEMBERSHIP

Q. Do you anticipate that Big Rivers will incur additional costs as a result of becoming a member of the Midwest ISO?

A. Yes, I anticipate that there will be ongoing costs that Big Rivers will incur associated with its membership in the Midwest ISO. In his testimony, Exhibit 4, Mr. Luciani has quantified the estimated costs that Big Rivers will pay in administrative charges to the Midwest ISO and the Federal Energy Regulatory Commission.

In addition, Mr. Luciani explains that Big Rivers could be required to share in the costs associated with investment in high-voltage transmission in the Midwest ISO region that may be made over the next decade. However, he explains that the amount of such investment is uncertain, as is the methodology that will be used to allocate any such costs to Midwest ISO members. Moreover, Big Rivers may benefit from such improvements. Given the uncertainties involved, Mr. Luciani has not attempted to quantify these costs.

Q. What about the cost of additional capital and staffing requirements that Big Rivers would incur in order to operate on an integrated basis with the Midwest ISO?

A. I anticipate that Big Rivers is likely to incur some level of additional costs, in the form of such items as additional staffing, professional services, travel to Midwest ISO stakeholder meetings, computer software, and computer hardware. It is difficult to ascertain the precise level of these costs, however, just as it is difficult to ascertain the offsetting savings that Big Rivers would obtain from having the Midwest ISO perform certain functional activities that Big Rivers currently performs for itself. Mr. Luciani has undertaken to estimate the additional internal costs to Big Rivers in his testimony, Exhibit 4, based on an estimate of costs prepared by Western Farmers Electric Cooperative, a generation and transmission cooperative located in Oklahoma, for its participation in the Southwest Power Pool. Big Rivers is relying on Mr. Luciani's calculation as a reasonable, conservatively derived estimate.

Q. Do these additional internal costs include the cost of hiring new employees needed by Big Rivers to interact with the Midwest ISO?

A. Yes, they do. Mr. Luciani has estimated that Big Rivers would require four additional full-time equivalent employees to handle its post-integration interaction with the Midwest ISO.

Q. Will these additional costs have an immediate effect on Big Rivers' operating results such that Big Rivers would not be able to meet the financial tests required under its credit agreements without a rate increase?

A. At this time, I do not believe that the cost estimates described above would prevent Big Rivers from meeting the tests required under its credit agreements, and thus Big Rivers does not anticipate needing immediately to file a rate adjustment solely in order to recover these additional costs.

Q. What are Big Rivers' plans for seeking a rate adjustment?

A. In the Unwind Transaction proceeding, Big Rivers committed to file for a general review of its financial operations and tariff within three years following the closing of the Unwind Transaction. Big Rivers currently plans to file for a rate adjustment to become effective January 1, 2012, and that filing could be made in conjunction with the filing committed to in the Unwind Transaction proceeding. That rate adjustment filing would include the additional costs incurred by Big Rivers as a Midwest ISO member.

For the convenience of the Commission, I have attached as Exhibit CWB-1 to my testimony Big Rivers' statement of revenues and expenses and balance sheet as of December 31, 2009.

Q. Do you foresee any additional marketing opportunities for Big Rivers as a result of Midwest ISO membership?

A. Yes. At times in the past, Big Rivers has been unable to purchase from, or sell surplus energy into, the market due to congestion. As Mr. Crockett explains in his testimony, Exhibit 2, there currently is no firm transmission available to bring significant amounts of power into the Big Rivers system. One of the advantages of joining the Midwest ISO is that the Midwest ISO has a congestion management process that is not available to Big Rivers, and the Midwest ISO will be able to use that process to relieve congestion adversely impacting Big Rivers upon Big Rivers' integration with the Midwest ISO's transmission system. This should enable Big Rivers to more readily access the market when it has surplus energy available, resulting in increased revenues from off-system sales.

V. <u>CREDITOR APPROVALS</u>

Q. Is Big Rivers required to obtain the approval of any of its creditors to join the Midwest ISO?

A. Yes. The Amended and Consolidated Loan Contract dated as of July 16, 2009, between Big Rivers and the United States of America requires Big Rivers to obtain the approval of the RUS before entering into a contract for the management of a material portion of the Big Rivers System. Big Rivers sent a request for that approval to RUS on February 1, 2010.

Big Rivers also is required by the Revolving Credit Agreement dated as of July 16, 2009, between Big Rivers and CoBank, ACB ("CoBank") to obtain the consent of CoBank, in writing, before entering into any contract for the management or operation or a material portion of its assets. Big Rivers sent a request for that approval to CoBank on February 1, 2010.

Q. Does this conclude your testimony at this time?

A. Yes.

VERIFICATION

I verify, state, and affirm that my testimony filed with this verification is true and accurate to the best of my knowledge, information, and belief.

C. William Blackburn

C. William Blackburn

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by C. William Blackburn on this the 26th day of January, 2010.

Vicki G. King

Notary Public, Ky. State at Large
My Commission Expires 03/03/2010

Exhibit CWB-1

BIG RIVERS ELECTRIC CORPORATION
STATEMENT OF REVENUES AND EXPENSES
MONTH ENDING DECEMBER 31, 2009

		BUDGET	CURRENT MONTH	PRIOR YEAR
1.	ELECTRIC ENERGY REVENUES	45,117,699.00	44,378,977.99	17,232,697.87
2.	INCOME FROM LEASED PROPERTY - NET			2,425,784.41
3.	OTHER OPERATING REVENUE AND INCOME	621,458.00	1,033,967.67	890,438.32
4.	TOTAL OPER REVENUES & PATRONAGE CAPITAL	45,739,157.00	45,412,945.66	20,548,920.60
5.	OPERATION EXPENSE-PRODUCTION-EXCL FUEL	4,255,346.00	4,651,759.28	
6.	OPERATION EXPENSE-PRODUCTION-FUEL	19,182,814.00	16,872,560.42	
7.	OPERATION EXPENSE-OTHER POWER SUPPLY	6,687,438.00	10,314,355.91	9,731,102.91
8.	OPERATION EXPENSE-TRANSMISSION	654,971.00	752,066.29	645,892.78
11.	CONSUMER SERVICE & INFORMATIONAL EXPENSE	71,902.00	75,645.08	69,973.40
12.	OPERATION EXPENSE-SALES	148,914.00	219,971.20	208,732.45
13.	OPERATION EXPENSE-ADMINISTRATIVE & GENERAL	1,928,982.00	4,049,141.15	1,855,797.72
14.	TOTAL OPERATION EXPENSE	32,930,367.00	36,935,499.33	12,511,499.26
15.	MAINTENANCE EXPENSE-PRODUCTION	2,349,583.00	4,518,230.85	
16.	MAINTENANCE EXPENSE-TRANSMISSION	413,657.00	910,160.00	652,043.67
18.	MAINTENANCE EXPENSE-GENERAL PLANT	14,275.00	24,452.06	13,191.87
19.	TOTAL MAINTENANCE EXPENSE	2,777,515.00	5,452,842.91	665,235.54
20.	DEPRECIATION & AMORTIZATION EXPENSE	2,874,090.00	2,942,086.99	601,006.73
21.	TAXES		87,635.87	48,044.70
22.	INTEREST ON LONG-TERM DEBT	4,147,044.00	4,316,793.16	6,010,540.00
23.	INTEREST CHARGED TO CONSTRUCTION-CREDIT	(61,776.00)	(14,191.00)	(12,293.00)
24.	OTHER INTEREST EXPENSE			341.29
25.	ASSET RETIREMENT OBLIGATIONS			
26.	OTHER DEDUCTIONS	5,259.00	15,378.69	6,271,719.38
27.	TOTAL COST OF ELECTRIC SERVICE	42,672,499.00	49,736,045.95	26,096,093.90
28.	OPERATING MARGINS	3,066,658.00	(4,323,100.29)	(5,547,173.30)
29.	INTEREST INCOME	16,096.00	57,137.39	35,321.98
30.	ALLOWANCE FOR FUNDS USED DURING CONST			
30.	ALLOWANCE FOR FUNDS USED DURING CONST			
32.	OTHER NON-OPERATING INCOME - NET		2,378.21	
34.	OTHER CAPITAL CREDITS & PAT DIVIDENDS		2,854.51	
35.	EXTRAORDINARY ITEMS		(6,785,981.56)	
36.	NET PATRONAGE CAPITAL OR MARGINS	3,082,754.00	(11,046,711.74)	(5,511,851.32)

ELECTRIC ENERGY REVENUE PER KWH SOLD	40.90	45.85	38.35
TOTAL OPER & MAINT PER KWH SOLD	32.37	43.79	29.32
TOTAL COST OF ELEC SERV PER KWH SOLD	38.68	51.38	58.08
PURCHASED POWER COST PER KWH PURCHASED	20.92	31.06	20.70

Exhibit CWB-1

BIG RIVERS ELECTRIC CORPORATION
STATEMENT OF REVENUES AND EXPENSES
YEAR TO DATE DECEMBER 31, 2009

		BUDGET	CURRENT YEAR	PRIOR YEAR
1.	ELECTRIC ENERGY REVENUES	344,905,707.00	326,729,694.44	204,519,278.49
2.	INCOME FROM LEASED PROPERTY-NET	15,584,941.00	15,888,814.21	29,347,945.24
3.	OTHER OPERATING REVENUE AND INCOME	11,862,836.00	14,603,909.45	10,239,392.78
4.	TOTAL OPER REVENUES & PATRONAGE CAPITAL	372,353,484.00	357,222,418.10	244,106,616.51
5.	OPERATION EXPENSE-PRODUCTION-EXCL FUEL	23,820,063.00	22,381,368.27	
6.	OPERATION EXPENSE-PRODUCTION-FUEL	97,125,947.00	80,654,642.49	
7.	OPERATION EXPENSE-OTHER POWER SUPPLY	106,825,730.00	115,826,139.46	112,760,847.60
8.	OPERATION EXPENSE-TRANSMISSION	7,793,533.00	8,256,703.81	7,222,057.22
11.	CONSUMER SERVICE & INFORMATIONAL EXPENSE	764,741.00	716,704.01	697,008.15
12.	OPERATION EXPENSE-SALES	1,484,262.00	551,735.10	723,821.25
13.	OPERATION EXPENSE-ADMINISTRATIVE & GENERAL	19,372,489.00	24,190,594.59	17,477,144.34
14.	TOTAL OPERATION EXPENSE	257,186,765.00	252,577,887.73	138,880,878.56
15.	MAINTENANCE EXPENSE-PRODUCTION	24,962,101.00	24,400,170.33	
16.	MAINTENANCE EXPENSE-TRANSMISSION	4,804,847.00	5,225,596.53	4,002,383.79
18.	MAINTENANCE EXPENSE-GENERAL PLANT	186,219.00	170,492.43	208,636.29
19.	TOTAL MAINTENANCE EXPENSE	29,953,167.00	29,796,259.29	4,211,020.08
20.	DEPRECIATION & AMORTIZATION EXPENSE	18,573,721.00	18,464,743.61	5,303,401.22
21.	TAXES	600,533.00	1,831,466.89	1,071,941.29
22.	INTEREST ON LONG-TERM DEBT	61,656,180.00	60,027,927.35	75,192,512.80
23.	INTEREST CHARGED TO CONSTRUCTION-CREDIT	(503,103.00)	(133,263.00)	(492,404.00)
24.	OTHER INTEREST EXPENSE	3,915.00	3,452.89	7,798.39
25.	ASSET RETIREMENT OBLIGATIONS			
26.	OTHER DEDUCTIONS	2,366,120.00	2,168,813.90	4,870,099.57
27.	TOTAL COST OF ELECTRIC SERVICE	369,837,298.00	364,737,288.66	229,045,247.91
28.	OPERATING MARGINS	2,516,186.00	(7,514,870.56)	15,061,368.60
29.	INTEREST INCOME	288,890.00	316,407.35	11,962,932.50
30.	ALLOWANCE FOR FUNDS USED DURING CONST			
32.	OTHER NON-OPERATING INCOME - NET		13,041.79	
34.	OTHER CAPITAL CREDITS & PAT DIVIDENDS	546,753.00	537,416.98	791,429.95
35.	EXTRAORDINARY ITEMS		537,978,261.13	
36.	NET PATRONAGE CAPITAL OR MARGINS	3,351,829.00	531,330,256.69	27,815,731.05

ELECTRIC ENERGY REVENUE PER KWH SOLD	40.96	41.94	39.66
TOTAL OPER & MAINT PER KWH SOLD	34.10	36.24	27.75
TOTAL COST OF ELEC SERV PER KWH SOLD	43.92	46.82	44.41
PURCHASED POWER COST PER KWH PURCHASED	22.71	23.81	20.94

Exhibit CWB-1

BIG RIVERS ELECTRIC CORPORATION
BALANCE SHEET
AS OF DECEMBER 31, 2009

	ASSETS	CURRENT YEAR	PRIOR YEAR	VARIANCE
1.	TOTAL UTILITY PLANT IN SERVICE	1931,116,387.99	1783,587,001.36	147,529,386.63
2.	CONSTRUCTION WORK IN PROGRESS	55,256,846.79	8,185,239.98	47,071,606.81
3.	TOTAL UTILITY PLANT	1986,373,234.78	1791,772,241.34	194,600,993.44
4.	ACCUM PROVISION FOR DEPR & AMORT	(908,099,499.70)	(879,073,594.80)	(29,025,904.90)
5.	NET UTILITY PLANT	1078,273,735.08	912,698,646.54	165,575,088.54
6.	NON-UTILITY PROPERTY - NET			
8.	INVEST IN ASSOC ORG PATRONAGE CAPITAL	3,576,487.80	3,384,730.60	191,757.20
9.	INVEST IN ASSOC ORG OTHER GENERAL FUNDS	684,993.00	684,993.00	
12.	OTHER INVESTMENTS	15,333.85	15,333.85	
13.	SPECIAL FUNDS	243,878,494.91	510,213.30	243,368,281.61
14.	TOTAL OTHER PROPERTY AND INVESTMENTS	248,155,309.56	4,595,270.75	243,560,038.81
15.	CASH - GENERAL FUNDS	243,538.53	6,193.09	237,345.44
16.	CASH - CONSTRUCTION FUNDS - TRUSTEE			
17.	SPECIAL DEPOSITS	571,738.53	570,634.47	1,104.06
18.	TEMPORARY INVESTMENTS	59,886,883.46	38,423,956.90	21,462,926.56
20.	ACCOUNTS RECEIVABLE - SALES OF ENERGY	39,902,094.99	18,640,706.45	21,261,388.54
21.	ACCOUNTS RECEIVABLE-OTHER NET	5,281,594.89	1,823,031.64	3,458,563.25
22.	FUEL STOCK	37,829,643.95		37,829,643.95
23.	MATERIALS & SUPPLIES - OTHER	20,412,537.94	756,008.54	19,656,529.40
24.	PREPAYMENTS	5,013,952.41	4,291,456.80	722,495.61
25.	OTHER CURRENT & ACCRUED ASSETS	2,312,955.29	4,554.61	2,308,400.68
26.	TOTAL CURRENT & ACCRUED ASSETS	171,454,939.99	64,516,542.50	106,938,397.49
27.	UNMORT DEBT DISC & EXTRAORD PROP LOSS	927,458.89	735,246.94	192,211.95
28.	REGULATORY ASSETS			
29.	OTHER DEFERRED DEBITS	6,672,013.82	91,890,500.65	(85,218,486.83)
30.	ACCUMULATED DEFERRED INCOME TAXES			
31.	TOTAL ASSETS AND OTHER DEBITS	1505,483,457.34	1074,436,207.38	431,047,249.96
	EQUITIES AND LIABILITIES			
32.	MEMBERSHIPS	75.00	75.00	
33.	NET PATRONAGE CAPITAL			
34.	OPERATING MARGINS - PRIOR YEAR	(244,639,283.68)	(272,715,872.23)	28,076,588.55
35.	OPERATING MARGINS - CURRENT YEAR	(6,977,453.58)	15,852,798.55	(22,830,252.13)
36.	NONOPERATING MARGINS - PRIOR YEAR	97,816,916.06	85,853,983.56	11,962,932.50
36.	NONOPERATING MARGINS - CURRENT YEAR	538,307,710.27	11,962,932.50	526,344,777.77
37.	OTHER MARGINS & EQUITIES	(5,116,422.80)	4,444,502.20	(9,560,925.00)
38.	TOTAL MARGINS & EQUITIES	379,391,541.27	(154,601,580.42)	533,993,121.69
39.	LONG-TERM DEBT - RUS	706,451,745.03	868,981,796.92	(162,530,051.89)
42.	LONG-TERM DEBT - OTHER	142,100,000.00	170,137,976.09	(28,037,976.09)
45.	TOTAL LONG-TERM DEBT	848,551,745.03	1039,119,773.01	(190,568,027.98)
49.	NOTES PAYABLE			
50.	ACCOUNTS PAYABLE	34,019,327.98	15,167,552.79	18,851,775.19
54.	TAXES ACCRUED	454,658.14	1,022,543.10	(567,884.96)
55.	INTEREST ACCRUED	9,097,431.78	8,018,660.07	1,078,771.71
56.	OTHER CURRENT & ACCRUED LIABILITIES	9,409,621.62	2,111,339.08	7,298,282.54
57.	TOTAL CURRENT & ACCRUED LIABILITIES	52,981,039.52	26,320,095.04	19,312,017.23
58.	DEFERRED CREDITS	207,347,581.11	156,300,498.43	51,047,082.68
47.	OPERATING RESERVES	17,211,550.41	7,297,421.32	9,914,129.09
46.	OBLIG UNDER CAPITAL LEASES - NON-CURRENT			
60.	TOTAL LIABILITIES AND OTHER CREDITS	1505,483,457.34	1074,436,207.38	431,047,249.96

COMMONWEALTH OF KENTUCKY
BEFORE THE
PUBLIC SERVICE COMMISSION OF KENTUCKY

Case No. 2010-00___

DIRECT TESTIMONY OF RALPH L. LUCIANI

ON BEHALF OF
APPLICANTS

FEBRUARY 2010

DIRECT TESTIMONY OF RALPH L. LUCIANI

I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Ralph L. Luciani. I am a Vice President of Charles River Associates ("CRA"). My business address is 1201 F St., NW, Washington, DC 20004.

Q. Please briefly describe your business and educational background.

A. I have more than 20 years of consulting experience analyzing economic and financial issues affecting the electricity industry, including those related to costing, ratemaking, generation planning, environmental compliance, fuel supply, competitive restructuring, stranded cost, asset valuation, wholesale power solicitations, power marketing, and Regional Transmission Organization ("RTO") costs and benefits. Prior to joining CRA, I was a Senior Vice President at PHB Hagler Bailly, and a Director at Putnam, Hayes and Bartlett, Inc. I hold a B.S. in Electrical Engineering and Economics from Carnegie Mellon University. I also hold an M.S. from the Graduate School of Industrial Administration at Carnegie Mellon University. I have previously testified before the Arkansas, Maryland, Kansas, Kentucky, Louisiana, Maryland, Missouri, Ohio and Pennsylvania state regulatory commissions, the Federal Energy Regulatory Commission ("FERC"), and the Ontario Energy Board. A copy of my resume is attached as Exhibit RLL-1.

Q. Can you describe your experience in studying the costs and benefits of an entity joining an RTO?

A. Yes, CRA has performed a number of cost-benefit studies related to RTO formation and entry into an RTO by individual utilities. I was a member of the CRA senior team that prepared the following studies:

1. The Benefits and Costs of Regional Transmission Organizations and Standard Market Design in the Southeast, prepared for the Southeastern Association of Regulatory Utility Commissioners in 2002.
2. The Benefits and Costs of Dominion Virginia Power Joining PJM performed for Dominion Virginia Power in 2004 (considering the costs and benefits of Dominion Virginia Power joining the PJM RTO),
3. The Southwest Power Pool ("SPP") Cost-Benefit Analysis performed for the SPP Regional State Committee in 2005 (considering the costs and benefits to individual utilities of forming the SPP RTO),
4. The RTO Cost-Benefit Analysis for Aquila Missouri in 2007 (considering the costs and benefits to Aquila Missouri of joining the Midwest Independent Transmission Operator ("Midwest ISO") or SPP or being stand-alone), and

5. The RTO Cost-Benefit Analysis for AmerenUE in 2007 (considering the costs and benefits to AmerenUE of remaining in the Midwest ISO, joining SPP, or being stand-alone).

In each of these studies, CRA has made use of its extensive knowledge of regional generation and transmission systems and electricity market structures and rules to specify a model representation of the regional electricity market. The computer simulation market model was used to project generation dispatch, production costs, inter-regional flows, and spot prices under various RTO-related scenarios. The results of the electricity modeling, supplemented with relevant RTO operating cost estimates, were then used to evaluate net benefits to individual regions and companies.

Q. What is the purpose of your testimony?

A. Big Rivers Electric Corporation ("Big Rivers") has asked me to perform an economic assessment of the options available to Big Rivers for the supply of Contingency Reserve[1] given that the Midwest Contingency Reserve Sharing Group ("MCRSG") to which Big Rivers belonged was terminated as of December 31, 2009. Big Rivers is currently obtaining Contingency Reserve under Attachment RR of the Midwest ISO Open Access Transmission Tariff ("OATT"), and can continue to do so until September 30, 2010.

[1] See Exhibit DGC-1 of the testimony of David Crocket for the North American Electric Reliability Corporation ("NERC') definition of Contingency Reserve.

Q. Can you summarize your conclusions?

A. Yes. In the near term, Big Rivers has no viable options for meeting its Contingency Reserve requirements other than stand-alone self-supply or joining the Midwest ISO. There are no other reserve sharing groups ("RSGs") currently available to Big Rivers. A stand-alone self-supply alternative is feasible if the smelters on the Big Rivers system are able to provide a significant amount (e.g., 200 MW) of interruptible load to Big Rivers that meets NERC standards. An analysis of the Midwest ISO alternative indicates that it would provide $32 million in net benefits to Big Rivers over the five-year period from 2011 to 2015 in comparison to a stand-alone case, excluding any cost for the 200 MW of qualifying Contingency Reserve supplied by the smelters in the stand-alone case. If the cost of the 200 MW of additional reserves in the stand-alone case is based on the cost of new peaking capacity, the net benefit of the Midwest ISO alternative is $133 million. While other qualitative-type considerations regarding joining the Midwest ISO may result in additional impacts to Big Rivers, these issues have been addressed for many years by a number of existing Midwest ISO generation and transmission ("G&T") cooperatives and there are risks associated with a reserve self-supply option as well. In sum, joining the Midwest ISO is the best available option for Big Rivers to meet its Contingency Reserve requirements at this time.

Q. What is Contingency Reserve?

A. Balancing Authorities, like Big Rivers, must operate their electrical systems according to NERC reliability standards.[2] Contingency Reserve is used by a Balancing Authority to balance resources and demand and restore interconnection frequency within defined limits following a disturbance on the electrical system, typically an unexpected generation outage. Contingency Reserve may be supplied from generation, controllable load resources, or coordinated adjustments to interchange schedules. A Balancing Authority may elect to fulfill its Contingency Reserve obligations by participating as a member of a reserve sharing group. At a minimum, the Balancing Authority or reserve sharing group must carry at least enough Contingency Reserve to cover the most severe single contingency. The Contingency Reserve must be able to be applied within 15 minutes of the start of the disturbance. After the 15-minute disturbance period, the Contingency Reserve must be restored within 90 minutes thereafter. It is important to recognize that the NERC requirement is that Big Rivers comply with this Contingency Reserve obligation when the need arises, not just that Big Rivers have in place a plan that is reasonably calculated to work when it is called upon.

Q. Describe Big Rivers' Contingency Reserve needs.

A. Big Rivers, as a Balancing Authority, must hold Contingency Reserve to meet NERC reliability standards. Big Rivers faces not only the requirement to apply its Contingency Reserve within 15 minutes of a disturbance on its system in the case

[2] NERC, Reliability Standards for the Bulk Electric Systems of North America, November 2009.

of an outage event taking place, but also to restore the Contingency Reserve to the NERC standard within 90 minutes thereafter. On a stand-alone basis, Big Rivers would require approximately 417 MW of Contingency Reserve based on its largest single generating unit, the D.B. Wilson plant. Big Rivers had been a member of the MCRSG which allowed for members to share reserves across the Midwest. Under this group membership, Big Rivers had to provide only 32 MW of Contingency Reserve. The MCRSG arrangement terminated December 31, 2009. Under the present Midwest ISO tariff, Big Rivers is no longer able to obtain Contingency Reserve service from the Midwest ISO without becoming a member.

II. BIG RIVERS' CONTINGENCY RESERVE OPTIONS

Q. What are Big Rivers' options for meeting its Contingency Reserve requirements?

A. Big Rivers has a number of possible ways of meeting its Contingency Reserve requirements, either through supplying the reserve needed up to the 417 MW stand-alone requirement or by reducing the amount of reserve required by entering into a reserve sharing arrangement. The Big Rivers options include:

1. Supplying Contingency Reserve from Big Rivers' existing generating capacity,
2. Purchasing Contingency Reserve from neighboring entities,

3. Constructing new generating units capable of supplying Contingency Reserve,
4. Entering into demand-side arrangements with Big Rivers' customers to decrease load when a system disturbance takes place,
5. Entering into a reserve sharing arrangement with a neighboring entity other than the Midwest ISO to decrease the amount of Contingency Reserve needed on the Big Rivers system, and
6. Joining the Midwest ISO, which will reduce the amount of Contingency Reserve needed on the Big Rivers system as well as allow Big Rivers to obtain Contingency Reserve through the Midwest ISO market.

Q. With respect to Option 1, what level of Contingency Reserve can be supplied by Big Rivers' existing generating capacity?

A. The Reid Combustion Turbine ("Reid CT") can ramp from cold condition to full operating capacity within 15 minutes, and thus is able to supply 65 MW of Contingency Reserve whenever the plant is not generating and is not out of service for maintenance. The Big Rivers coal plants cannot ramp from a cold start to full operating output within the 15 minutes required to qualify as Contingency Reserve. To supply Contingency Reserve, a coal plant has to be generating at an output level less than its maximum level. The amount of additional MW that the unit then could provide within 15 minutes would qualify as Contingency Reserve, and depends on the unit's ramp rate. Based on data supplied by Big Rivers, the Big Rivers coal units, excluding D.B. Wilson, could supply as much as 222 MW of Contingency Reserve within 10 minutes (conservatively allowing 5 minutes for the units to commence increasing output in response to a disturbance). Thus, as much as 287 MW (65 + 222) of Contingency Reserve could be physically supplied by the Big Rivers existing generating units. At 287 MW in total, this option cannot meet the Big Rivers 417 MW stand-alone Contingency Reserve requirement by itself.

Q. What are the cost considerations in supplying Contingency Reserve from the existing Big Rivers generating capacity?

A. The Big Rivers generating units generally will be generating energy in an hour if their fuel and variable O&M costs are lower than the prevailing market price of energy. If the power generated is not needed by Big Rivers, it is sold off-system at the market price. Thus, the cost of using a Big Rivers unit to provide Contingency Reserve is the market price of energy for the energy that otherwise would have been generated by the unit net of the fuel and variable O&M cost avoided by not generating. The Reid CT has historically not generated often (i.e., its fuel costs are generally higher than prevailing market prices for energy), and thus is available to supply Contingency Reserve fairly economically.

However, supplying Contingency Reserve from the Big Rivers coal plants can be costly, particularly during peak demand periods. In these periods, the plants would generally be operating at full output. Holding the units at lower output levels to supply Contingency Reserve will result in additional cost to Big Rivers to purchase power at market prices or a loss in revenue by Big Rivers from selling less power at market prices. Moreover, the units burn fuel less efficiently when operating at less than full output, making the fuel costs higher on a per MWh generated basis. Finally, a unit may have to be committed to operate at minimum load at times when the prevailing market prices for power would normally dictate that the unit not be generating at all. For all of these reasons, it is generally optimal to limit the need for Contingency Reserve and to supply as much as possible from peaking-type capacity.

Q. With respect to Option 2, is purchasing reserve capacity from neighboring entities a viable option?

A. Big Rivers personnel investigated this option, and no reserve capacity is currently available for purchase from a neighboring system. While such capacity potentially could become available, it is likely to be available only under short-term arrangements as neighboring entities would be constructing generating capacity to meet their own needs, and generally would be selling capacity only when their needs have not yet materialized.

Q. With respect to Option 3, is constructing new capacity capable of supplying Contingency Reserve a viable option?

A. Not in the short term, but potentially in the longer term. For this purpose, peaking-type capacity would be the choice. New peaking capacity likely would take 1 to 2 years to put in place. However, building a new generating unit simply to provide Contingency Reserve is likely to be a fairly expensive option, particularly given that the unit would not be allowed to generate energy at the time of peak demand. For example, PJM derives an estimate of the cost to construct new peaking capacity as part of its capacity market operations. The latest estimate is for a new CT to incur $113/kW-year in fixed costs (capital and fixed O&M).[3] The new unit would be expected to offset this fixed cost with $16/kW-year in energy margins when generating. However, holding the unit back to supply Contingency Reserve would not allow for this offset to take place.

Q. With respect to Option 4, is entering into demand-side arrangements with its customers to decrease load when a disturbance takes place a viable option?

A. Yes, potentially. My understanding is that there have been discussions between Big Rivers and two aluminum smelter customers served by one of its members about idling a pot line temporarily during a Contingency Reserve event. There has been some indication that perhaps 200 MW of smelter demand would be interruptible within 15 minutes, at a price as yet undetermined. Given that Big Rivers would need to restore its Contingency Reserve 90 minutes after the initial 15-minute disturbance period, the interrupted smelter load may need to stay off-

[3] PJM RPM Cone and E&AS Values for 2012/2013 Base Residual Auction, Based on FERC Order of 3-26-09, April 8, 2009. RTO-wide values cited.

line for an extended period of time if the original cause of the disturbance cannot be remedied within 90 minutes. It is unclear whether the smelter load may be interruptible to this extent.

Q. With respect to Option 5, is entering into a reserve sharing agreement with a neighboring entity other than the Midwest ISO a viable option?

A. Along with the Midwest ISO, Big Rivers is directly interconnected with Tennessee Valley Authority ("TVA"), E.ON, and Henderson Municipal Power and Light. My understanding is that E.ON and East Kentucky Power Cooperative ("EKPC"), previously members of the Midwest ISO Reserve Sharing Group, have entered into reserve sharing arrangements with TVA. My understanding is that entering into a reserve sharing arrangement with TVA is legally not an option for Big Rivers. Thus, entering into reserve sharing arrangements with TVA, E.ON and EKPC is currently not an option available to Big Rivers. Big Rivers personnel contacted the VACAR Reserve Sharing Group, which encompasses utilities in the states of Virginia, North Carolina and South Carolina, but this group was not willing to offer membership to Big Rivers. Big Rivers also contacted the SPP Reserve Sharing Group, and determined that joining the SPP group is a potential option. For this option to be viable, Big Rivers would need to obtain firm transmission across TVA to an SPP Reserve Sharing Group member interconnected with TVA, namely Entergy or Associated Electric Cooperative, Inc. ("AECI").

Q. Did Big Rivers further evaluate the option of joining the SPP Reserve Sharing Group?

A. Yes. Joining the SPP Reserve Sharing Group would require substantial firm transmission, as much as 390 MW, from Entergy/AECI in SPP across TVA to Big Rivers. A much smaller amount of firm transmission (only Big Rivers' assigned share of the SPP Contingency Reserve requirement) would be needed from Big Rivers to SPP. Given the likelihood of only limited firm transmission rights being available from SPP across TVA to Big Rivers, joining the SPP Reserve Sharing Group was considered by Big Rivers as potentially only supplying a portion of Big Rivers' Contingency Reserve requirements.

To assess transmission availability, Big Rivers requested firm point-to-point transmission across TVA in September 2009. The request was for 200 MW (2 x 100) of firm transmission from Entergy or AECI to Big Rivers and 10 MW (2 x 5) of transmission from Big Rivers to Entergy or AECI. Including ancillary charges, the TVA point-to-point transmission rate is $23,556/MW-year. For 210 MW, the cost would be $4.9 million per year. TVA considered the two 100 MW requests separately, and determined in December 2009 that to provide 100 MW of transmission to Big Rivers would require an additional $4.9 million in transmission upgrades on the TVA system, and the transmission service would not be available until mid-2012 at the earliest. The 10 MW of transmission from

Entergy/AECI to Big Rivers was potentially available. However, TVA further noted that a System Impact Study with the Midwest ISO, E.ON and Entergy/AECI would be required before any transmission service could be obtained.

Given that the firm transmission across TVA, if available at all, would not be available until mid-2012 at the earliest, the SPP Reserve Sharing Group is not a near-term option for Big Rivers. Further, as SPP transitions to a Day 2 market, there is the potential for SPP, like the Midwest ISO, to also require market membership in order to participate in Contingency Reserve sharing.

Q. **With respect to Option 6, is Big Rivers joining the Midwest ISO a viable option for meeting its Contingency Reserve requirements?**

A. Yes. If Big Rivers joins the Midwest ISO, the Midwest ISO will manage the Contingency Reserve required by the entire Midwest ISO, including Big Rivers, through its Ancillary Services Market ("ASM"). Under this option, Big Rivers will purchase Contingency Reserve service for its load through the ASM and may sell Contingency Reserve capacity from its generating units into this market. Joining the Midwest ISO market will have a number of impacts on Big Rivers which will be discussed in detail in the following section.

Q. Aside from the cost impacts, is the need to restore Contingency Reserve within 90 minutes after the initial 15-minute disturbance period an issue with respect to a stand-alone alternative?

A. Yes, potentially. My understanding is that Big Rivers would have certain rights under emergency conditions under the reserve sharing agreement or Midwest ISO options that would not be in place under a stand-alone alternative. Moreover, the significant amount of Contingency Reserve required under a stand-alone arrangement (417 MW) may make it more difficult to restore Contingency Reserve during a disturbance. For example, if the 231 MW Green Unit 1 coal generating unit unexpectedly went out of service on the Big Rivers system, then 231 MW of Contingency Reserve would be applied within 15 minutes leaving 206 MW (417 – 231) of remaining Contingency Reserve. If the generating unit could not be placed back into service within 90 minutes thereafter, Big Rivers would need to obtain an additional 231 MW of Contingency Reserve to restore reserves to 417 MW within that 90 minute period. In short, in the space of 105 minutes, Big Rivers could be called upon to have or obtain 648 MW (417 + 231) of Contingency Reserve, which will be difficult to meet absent available Contingency Reserve off-system. Under an RSG in which Big Rivers is required to hold, for example, 32 MW of Contingency Reserve, the same situation would require Big Rivers to have or obtain 263 MW (32 + 231) of Contingency Reserve within 105 minutes, a still difficult but potentially more manageable position. If Big Rivers were a member of the Midwest ISO, the Midwest ISO would simultaneously ensure meeting Contingency Reserve requirements for Big Rivers and the rest of the Midwest ISO by supplying available resources through the ASM.

Q. Could Big Rivers reduce its Contingency Reserve needs by reducing the output of its largest coal unit, D.B. Wilson?

A. Yes, if Big Rivers is not part of an RSG or the Midwest ISO, the D.B. Wilson plant could be operated at a reduced output level as low as 280 MW. This would limit Big Rivers' Contingency Reserve needs to 280 MW, as its next largest single contingency is 231 MW (Green Unit 1). However, losing 137 MW (417 – 280), or 33%, of the output of the low-cost D.B. Wilson plant would be prohibitively expensive. In 2008 the plant produced 3,026 GWH of energy at an average fuel/variable O&M cost of $20.9 per MWh.[4] At, for example, market energy prices of $50 per MWh, not having 33% of the output of the unit would cost nearly $30 million per year in additional purchase costs net of avoided fuel costs. The cost would be even higher since the plant would operate less efficiently at a lower output level. Moreover, Big Rivers would still need to find a way to supply the 280 MW of Contingency Reserve needed.

Q. Can you summarize the options available to Big Rivers for meeting its Contingency Reserve requirements?

---

[4] Energy Velocity Power Database.

A. Yes. In the near term, Big Rivers has no viable options other than stand-alone self-supply or joining the Midwest ISO. As discussed above, there are no other RSGs currently available to Big Rivers. A stand-alone supply is feasible if the smelters are willing to supply significant interruptible load that meets NERC standards. The projected net cost to Big Rivers of joining the Midwest ISO in comparison to the stand-alone supply of Contingency Reserve is analyzed in the next section.

III. STAND-ALONE OPTION VERSUS JOINING THE MIDWEST ISO

Q. Aside from the Contingency Reserve issue, what are the costs and benefits of Big Rivers joining the Midwest ISO?

A. There are a number of costs and benefits. On the benefits side, Big Rivers would be able to integrate the commitment and dispatch of its units with the Midwest ISO market and to import energy from the Midwest ISO without incurring wheeling charges. This should serve to increase sales revenues and/or reduce purchase costs for Big Rivers and thereby reduce the cost to serve native load. On the cost side, there would be administrative charges assessed by the Midwest ISO, which include payments to the Federal Energy Regulatory Commission, and Big Rivers' internal costs for interfacing with the Midwest ISO. In addition, there are a number of other important qualitative-type issues, the impact of which cannot be easily quantified.

Q. What analysis did you perform to assess the cost to serve Big Rivers' load either on a stand-alone basis or as a member of the Midwest ISO?

A. CRA analyzed two separate scenarios using the GE MAPS model:

1. Big Rivers supplying Contingency Reserve on a stand-alone basis ("Stand-alone Case").
2. Big Rivers as a transmission owner in the Midwest ISO ("Midwest ISO Case").

Stand-alone Case: In this scenario, it was assumed that Big Rivers would not join an RTO or an RSG and would need 417 MW of Contingency Reserve. It was assumed that Big Rivers would obtain 65 MW of Contingency Reserve from the Reid CT and 200 MW of reserve through arrangements with the smelters or the construction of new peaking units, or both. The remaining 152 MW of Contingency Reserve needed was assumed to be supplied by Big Rivers' coal units operating at less than their maximum output.

Midwest ISO Case: In this scenario, it was assumed that Big Rivers joins the Midwest ISO as a transmission owner and full member of the Midwest ISO market. Consistent with the former Midwest ISO Contingency Reserve Sharing

Group arrangement, Big Rivers' load was assumed to require 32 MW of Contingency Reserve, of which 40% must be spinning.

CRA performed this analysis using the GE MAPS model. The GE MAPS analyses were performed for the calendar years 2011 and 2014, with the results for the five-year period from 2011 to 2015 interpolated from these runs. For purposes of this analysis, the results were derived for the Big Rivers Balancing Authority in the aggregate, which includes Henderson Municipal Power and Light.

Q. Can you further describe the GE MAPS modeling?

A. Yes. GE MAPS is a detailed economic dispatch and production cost model that simulates the operation of the electric power system taking into account transmission topology. The GE MAPS model determines the security-constrained commitment and hourly dispatch of each modeled generating unit, the loading of each element of the transmission system, and the locational marginal price ("LMP") for each generator and load area. The GE MAPS model was used by CRA in all of the prior RTO market cost-benefit studies it has performed, as well as to support the U.S. Department of Energy in conducting the August 2006 National Electric Transmission Congestion Study. In this study, GE MAPS was set up to model the Eastern Interconnection of the United States and Canada. CRA used its GE MAPS data base to perform the analysis.

The GE MAPS was modeled to reflect different impediments to Big Rivers' trade with neighboring entities under of the two scenarios. The GE MAPS model includes dispatch seams charges to reflect impediments to trade between control areas that take place on a real-time basis, including wheeling charges and imperfect knowledge regarding flows outside of the control area. In the Stand-alone Case, Big Rivers' dispatch seams charges were included in GE MAPS with each of its neighboring entities (e.g., TVA, Midwest ISO, and E.ON). In the Midwest ISO Case, dispatch seams charges between Midwest ISO and Big Rivers in GE MAPS are eliminated and the Midwest ISO dispatch seams charge is applied between Big Rivers and non-Midwest ISO members. Along with real-time dispatch impediments, there are also impediments with respect to day-ahead commitment. A Balancing Authority area with responsibility for reliably committing generating units for operation the next day cannot fully rely on units outside of the control area over which the control area has no direct control, and thus must often commit its own units to ensure reliability. In an RTO, the commitment economics can be integrated across a larger footprint. In the Midwest ISO scenario in GE MAPS, the Big Rivers units are committed jointly with Midwest ISO units reflecting Big Rivers' entry into the Midwest ISO market. A listing of the GE MAPS modeling input data is provided in Exhibit RLL-2.

Q. Can you describe further how the cost to serve Big Rivers' load was derived using the GE MAPS analysis?

A. Yes. CRA has performed this type of analysis for each of its RTO cost-benefit studies. As noted above, the GE MAPS cases analyzed reflect varying degrees of impediments to trade between Big Rivers and the Midwest ISO. Reductions in the impediments to trading should result in production cost savings. Generation production costs are actual out-of-pocket costs for operating generating units that vary with generating unit output; these comprise fuel costs, variable O&M costs, and the cost of emission allowances. By decreasing impediments to trading, additional generation from utility areas with lower cost generation replaces higher cost generation in other utility areas.

Increases or decreases in production cost in any particular utility area, by themselves, do not provide an indication of benefits for that area, because that area may simply be importing or exporting more power than it did under base conditions. For example, a utility that increases its exports would have higher production costs (because it generates more power that is exported) and would appear to be worse off if the benefits from the additional exports were not considered. Similarly, a utility that imports more would have lower production costs, but higher purchased power costs. In either circumstance – an increase in imports or exports – an accounting of the trade benefits between buyers and sellers must be made in order to assess the actual impact on utility area benefits.

Increased trading activity provides benefits to both buying parties (purchases at a lower cost than owned-generation cost) and selling parties (sales at a higher price than owned-generation cost). In practice, the benefits of increased trade are divided between buying and selling parties. For example, the "split-savings" rules that governed traditional economy energy transactions between utilities under cost-of-service regulation resulted in a 50-50 split of trading benefits.[5]

Traditional cost-of-service regulation differs from a fully deregulated retail market, in which individual customers and/or load-serving entities buy all their power from unregulated generation providers at prevailing market prices. In such a deregulated market, benefits to load can be ascertained mostly in terms of the impact that changes to prevailing market prices have on power purchase costs. For Big Rivers, in which cost-of-service rate regulation is in effect, the energy portion of utility rates reflects the production cost for the utility's owned generating units, plus the cost of "off-system" purchased energy, net of revenues from "off-system" energy sales (i.e., Adjusted Production Costs). In turn, utility customers under cost-of-service regulation pay for the fixed costs of owned-generating units through base rates. Thus, in this analysis, both the production

[5] Consider a simple two-company example. Assume there is a $16 marginal cost to generate in Company A's control area and a $20 marginal cost to generate in Company B's control area and there is no trade. Now assume through a reduction in trade impediments that 1 MW can be traded from A to B over the inter-tie between A and B. Company A will generate 1 MW more at a production cost of $16, while Company B will generate 1 MW less at a production cost savings of $20. Thus, the total saving in production cost is $4 (i.e., $20 – $16). If the trade price is set, for example, at a 50/50 split savings price, Company A will receive $18, for a trade benefit of $2 ($18 – $16), and Company B will pay $18, for a trade benefit of $2 ($20 – $18). The total trade benefit of $4 ($2 + $2) will match the total production cost saving of $4.

cost of operating the Big Rivers generating plants and the associated Big Rivers trading activity (purchases and sales) must be assessed.

The production cost of the generating units is derived directly from the GE MAPS outputs for each case. Note that a simple calculation of regional Adjusted Production Costs using LMPs will miss the economic impact of price differentials between buying and selling regions (i.e., trade benefits). As such, for purposes of deriving the impact of trading with adjoining regions, CRA applies a methodology developed in consultation with Missouri stakeholders during CRA's work in the 2007 RTO cost-benefit studies performed for Aquila and AmerenUE. In the absence of existing Financial Transmission Rights ("FTRs") to help evaluate the value received by trading parties resulting from these price differentials, CRA captures these impacts through a split-savings methodology. Under this methodology, the net hourly GE MAPS tie-line flows into and out of Big Rivers are used as a proxy for purchase and sale transactions by Big Rivers. In each hour, the net interchange is derived using tie-line flows to assess whether Big Rivers is a net importer (purchaser) or exporter (seller) of power. If Big Rivers is a net purchaser in the hour, the net purchase amount is multiplied by the weighted average split-savings price for tie-lines with flows into the control area. Similarly, if Big Rivers is a net exporter (seller) in the hour, the net sale amount is multiplied by the average split-savings price for tie-lines with outgoing flows.

Q. Based on the GE MAPS analysis described above, what were the costs to serve the Big Rivers load under the Stand-alone and Midwest ISO Cases?

A. Results are summarized in Table 1. As shown, in the Midwest ISO Case, the generation of the Big Rivers units increases, while the quantity of purchases decreases and the quantity of sales increases. The increase in the generation of the Big Rivers units in the Midwest ISO Case is unsurprising given that 152 MW of Big Rivers coal units are providing Contingency Reserve in the Stand-alone Case, and cannot be called upon to generate.[6] The increased generation by Big Rivers' units in the Midwest ISO Case allows for fewer purchases and increased sales to be made by Big Rivers.

Table 1
Sources and Costs to Serve Big Rivers Load
Stand-alone Case vs. Midwest ISO Case
(GWH or Millions of nominal as-spent dollars)

	Stand-Alone		Midwest ISO		Increase	
	2011	2014	2011	2014	2011	2014
GWH						
+ Generation	10,729	10,719	11,464	11,433	735	714
+ Purchases	1,670	1,903	1,075	1,348	(595)	(555)
- Sales	184	332	324	492	140	159
= Total	12,215	12,290	12,215	12,290	0	0
M$						
+ Generation Costs	$347	$364	$371	$389	$24	$25
+ Purchase Costs	$58	$80	$30	$49	($29)	($32)
- Sales Revenue	$7	$14	$14	$22	$6	$7
= Total	$398	$430	$387	$416	($11)	($14)

6 See Table 3-4 in Exhibit RLL-3 for individual unit generation impacts. As shown in that table, each of the Big Rivers generating units increases output in the Midwest ISO case except for Reid Steam. Reid Steam, a less-efficient coal unit, operates more in the Stand-alone case as it is committed more often to provide reserves in this case.

In terms of costs, moving to the Midwest ISO increases the production cost (fuel, variable O&M and emission allowances) of the Big Rivers generating units as the units generate significantly more, but the savings in terms of Big Rivers' purchase costs more than offset this increase.[7] The additional sales in the Midwest ISO Case also further offset the increase in generation costs. Overall, the cost to serve the Big Rivers load decreases by $11 million in 2011 and $14 million in 2014 in the Midwest ISO case. The present value of the decrease in cost over the five-year period from 2011-2015 is $56.7 million.[8] See Exhibit RLL-3 for further detail.

Q. What administrative charges would be assessed by the Midwest ISO to Big Rivers?

A. The Midwest ISO assesses administrative charges under Midwest ISO OATT Schedules 10, 16 and 17. The billing determinants are a mixture of demand and energy use by each transmission owner. As part of its budgeting process, the Midwest ISO prepares a five-year projection of these charges on a $/MWh basis, which we have used to estimate the annual charges to Big Rivers.[9] For 2011, the estimated Midwest ISO administrative charges incurred by Big Rivers are $4.6 million, and the present value over the five-years from 2011 to 2015 is $17.9 million. See Exhibit RLL-3 for further detail.

[7] The GWH of purchases includes Southeastern Power Administration ("SEPA") generation, but for purposes of this analysis the cost to Big Rivers of the SEPA generation is not considered as it would be identical in both cases.

[8] Present value figures cited herein are as of January 1, 2011, and reflect a discount rate of 5.83%.

[9] Midwest ISO Five Year Forecast 2010-2012 Final Budget, December 8, 2009.

Q. What additional payments would be made to the FERC by Big Rivers under Midwest ISO membership?

A. As a cooperative, Big Rivers is currently exempt from paying FERC administrative charges. However, as a member of an RTO, Big Rivers would be obligated to pay these charges based on transmission system use. The Midwest ISO assesses FERC charges under its Schedule 10-FERC. Using the Midwest ISO projection for this charge in 2010, the estimated Big Rivers payments to FERC are $0.7 million in 2011, with a present value over the five-year 2011-2015 period of $3.1 million. See Exhibit RLL-3 for further detail.

Q. What would be the cost of the Big Rivers capital and staffing requirements for interfacing with the Midwest ISO as a member?

A. Big Rivers would need to interface with the Midwest ISO market, and this could include additional staffing, professional services, travel, computer software, computer hardware and other costs. Because the Midwest ISO would be performing certain functions now performed or contracted for by Big Rivers, there may be offsetting savings as well. It is my understanding that Big Rivers has begun reviewing these costs, but does not have specific budget numbers available at this time.

Western Farmers Electric Cooperative ("Western Farmers"), a G&T cooperative located in Oklahoma, estimated these types of internal costs as part of the SPP Cost Benefit Study prepared by CRA. In that study, Western Farmers estimated that interfacing with the SPP RTO market would require four additional full-time equivalents ("FTE"), and $260,000 per year in professional services and travel. Western Farmers also estimated that it would save some O&M and ongoing capital investment costs through SPP providing standard reliability/transmission provider functions. Given that Western Farmers is a G&T cooperative like Big Rivers, I have applied these internal cost estimates in the Big Rivers analysis. For conservatism, I have not netted the Western Farmers estimated savings through the reliability/transmission provider functions that the RTO performs. Under this assumption, the estimated internal cost to Big Rivers in the Midwest ISO Case would be $0.8 million in 2011, and a present value over the five-year 2011-2015 period of $3.4 million. See Exhibit RLL-3 for further detail.

Q. How was the cost of obtaining 200 MW of additional reserves in the Stand-alone Case estimated?

A. As noted above, it was assumed in the Stand-alone Case that Big Rivers would obtain 65 MW of Contingency Reserve from the Reid CT and 200 MW of reserves through arrangements with the smelters or the construction of new peaking units, or both. For purposes of this analysis, the annual cost of this additional 200 MW of reserves is estimated to be equal to the annualized cost of new peaking power. Under this assumption, the cost of obtaining the 200 MW of additional reserves for the Stand-alone case is $22.0 million in 2011 and $100.5 million in present value over the five-year 2011-2015 period. See Exhibit RLL-3 for further detail.

Q. Can you summarize the overall net benefits to Big Rivers of the Midwest ISO Case relative to the Stand-alone Case?

A. Results are summarized in Table 2. In the table, benefits are shown as positive numbers and costs as negative numbers. As shown, the overall benefits to Big Rivers of the Midwest ISO case are $132.8 million in present value over the five-year 2011-2015 period.

Table 2
Summary of Benefits (Costs) of Joining the Midwest ISO in Comparison to Stand-alone
(Millions of nominal, as-spent dollars)

	2011	2012	2013	2014	2015	Present Value
Decreased Cost to Serve Big Rivers Load	11.0	12.1	13.3	14.4	14.8	56.7
Midwest ISO Administrative Charges	(4.6)	(4.1)	(3.9)	(3.9)	(4.1)	(17.9)
FERC Charges	(0.7)	(0.7)	(0.7)	(0.7)	(0.7)	(3.1)
Internal Staffing/Equipment Costs	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(3.4)
Subtotal	5.0	6.6	7.9	9.0	9.2	32.3
Cost Avoided for 200 MW of New Reserves	22.0	22.6	23.1	23.7	24.3	100.5
Net Benefits	27.0	29.2	31.1	32.7	33.5	132.8

Because the cost that may be incurred for 200 MW of additional reserves in the Stand-alone Case if it were to be obtained from the smelters is not yet known, a subtotal is calculated excluding this cost. As shown, the benefits of joining the

Midwest ISO relative to the Stand-alone Case would be $32.3 million in present value excluding any cost incurred for the 200 MW of additional reserves.

Aside from the items quantified above, there are a number of other issues with respect to Big Rivers joining the Midwest ISO, including the impact on Big Rivers of transmission expansion in the Midwest ISO, the Midwest ISO Ancillary Services Market, transmission rates and revenues and transmission planning.

Q. **What impact might there be on Big Rivers with respect to sharing of the cost of a high-voltage transmission expansion on the Midwest ISO system?**

A. To integrate Great Plains wind power, significant investment in new high-voltage transmission may be made in the Midwest ISO region over the next decade. The transmission investment amount that may be made is uncertain. If Big Rivers' supply contracts with its customers qualify as grandfathered agreements ("GFAs") under the Midwest ISO OATT, this load currently would be exempt from paying for these expansion costs. Further, cost allocation procedures are under discussion in the Midwest ISO and currently do not require a full spreading of transmission costs across the region for high-voltage overlays. Moreover, additional transmission expansion, if it does take place, would allow for greater wind power to be exported across the Midwest ISO, thus likely decreasing over time the prevailing cost to purchase power in the Midwest ISO. As a member of the Midwest ISO, Big Rivers would benefit under an integrated market from this increased wind power access. To the extent that transmission improvements may be approved for the Big Rivers transmission system, other Midwest ISO members may share in the cost of those improvements as well. Given these uncertainties in how much transmission will be built, how much it will cost, how the costs will be allocated, the GFA status of the Big Rivers load, and the resulting offsetting benefits from increased access to wind power, I have not quantified the net impact of this issue.[10] Ultimately, transmission costs are likely to be spread region-wide only with a showing that there are region-wide benefits.

Q. What impacts might there be on Big Rivers through participation in the Midwest ISO's Ancillary Services Market?

A. The Midwest ISO implemented an Ancillary Services Market in January 2009, which integrates the procurement and use of Regulation and Contingency Reserve with the energy market. All else being equal, an ASM should serve to make the supply of these ancillary services more economic. Under the ASM, Big Rivers' load would incur costs to purchase regulation and Contingency Reserve. However, Big Rivers' generating units would receive revenues for providing these ancillary services. Self-scheduling of the required reserve is permitted, meaning that the Big Rivers generating units could be used to supply the required

10 For example, if $3 billion is spent on high-voltage transmission in the Midwest ISO, 80% of the transmission cost is spread on a load-ratio basis at an investment carry cost of 15%, Big Rivers' load ratio share is 1.7%, and 50% of the Big Rivers' load does not qualify as GFA status, the annual cost to Big Rivers would be ($3 billion * 80% * 15% * 1.7% * 50%), or $3.1 million per year. However, this does not address the offsetting benefits from greater access to the Great Plains wind power.

reserves for the Big Rivers load.[11] Self-scheduling would be generally consistent with Big Rivers' operation in the past as a member of the Midwest Contingency Reserve Sharing Group. Given this self-scheduling option, it is likely that Big Rivers would be no worse off under the ASM and possibly better off if it is able to sell additional ancillary services from its generating units to others in the Midwest ISO.

Q. Can you describe some of the other qualitative considerations?

A. Yes. Transmission revenues for wheeling "through or out" of the Midwest ISO are shared among Midwest ISO entities according to formulations in the Midwest ISO tariff.[12] Given that the Big Rivers transmission system is surrounded by the TVA, E.ON and Midwest ISO transmission systems, it currently can often be "bypassed" by entities seeking to transport power to/from TVA, SPP and the Midwest ISO. Thus, inclusion in the Midwest ISO may permit Big Rivers to collect additional transmission revenues under the Midwest ISO OATT than it would otherwise as a non-Midwest ISO member. There are a number of uplift payments and charges assessed by the Midwest ISO to market participants that take place as part of the Midwest ISO market process, including revenue sufficiency guarantee payments, revenue neutrality uplift amounts, and excess congestion disbursements. These uplifts are designed to leave the Midwest ISO in a revenue-neutral position. From Big Rivers' perspective, these uplifts may

[11] Midwest ISO FERC Electric Tariff, Fourth Revised Volume No. 1, Original Sheet Nos. 1829 and 1844.

[12] Midwest ISO FERC Electric Tariff Rate Schedule 1, Appendix C.

largely offset one another, but ultimately could impact Big Rivers in a positive or negative direction. Big Rivers will nominate and hold Financial Transmission Rights and Auction Revenue Rights ("ARRs") as a member of the Midwest ISO that will be expected to cover its internal congestion costs (the difference in locational prices between Big Rivers' load withdrawals and power supply injections). However, in practice, the value of the FTRs and ARRs may be more or less than actual congestion costs. As a member of the Midwest ISO, Big Rivers would also benefit from having its transmission planning process conducted along with the Midwest ISO planning process. This should provide more complete information to guide expansions of the Big Rivers transmission system.

Q. Are there other G&T cooperatives that are members of the Midwest ISO?

A. Yes, there are a number, including Great River Energy, Hoosier Energy, Southern Illinois Power Cooperative, Wabash Valley Power Association, and Wolverine Power Supply Cooperative. Dairyland Power Cooperative is becoming a full member of the Midwest ISO market in June 2010. The experience of other G&T cooperatives with their Midwest ISO membership and in confronting these qualitative issues should be helpful in Big Rivers' transitioning to being a member of the Midwest ISO market.

Q. Are there qualitative concerns for the stand-alone option as well?

A. Yes, as discussed above, the short-term availability of the stand-alone option depends on the smelters being able to supply significant amounts of qualifying reserves that may need to be interrupted for a significant amount of time. Big Rivers would have to rely on the smelters being able to provide these reserves over a number of years. Also, as noted above, the ability to obtain emergency reserves is potentially more difficult in a Stand-alone Case. Further, being a member of the Midwest ISO market also provides a means for Big Rivers to sell power from its generating stations into this market if the Big Rivers smelter load declines from current projected levels.

IV. CONCLUSION

Q. Can you summarize your conclusions?

A. Yes. In the near term, Big Rivers has no viable options for meeting its Contingency Reserve requirements other than stand-alone self-supply or joining the Midwest ISO. There are no other reserve sharing groups currently available to Big Rivers. A stand-alone self-supply alternative is feasible if the smelters on the Big Rivers system are able to provide a significant amount (e.g., 200 MW) of interruptible load to Big Rivers that meets NERC standards. An analysis of the Midwest ISO alternative indicates that it would provide $32 million in net benefits to Big Rivers over the five-year period from 2011 to 2015 in comparison to a Stand-alone Case, excluding any cost for the 200 MW of qualifying Contingency Reserve supplied by the smelters in the Stand-alone Case. If the cost of the 200 MW of additional reserves in the Stand-alone Case is based on the cost of new peaking capacity, the net benefit of the Midwest ISO alternative is $133 million. While other qualitative-type considerations regarding joining the Midwest ISO may result in additional impacts to Big Rivers, these issues have been addressed for many years by a number of existing Midwest ISO G&T cooperatives and there are risks associated with a reserve self-supply option as well. In sum, joining the Midwest ISO is the best available option for Big Rivers to meet its Contingency Reserve requirements at this time.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

I verify, state, and affirm that my testimony filed with this verification is true and accurate to the best of my knowledge, information, and belief.

Ralph L Luciani

Ralph L. Luciani

DISTRICT OF COLUMBIA)

SUBSCRIBED AND SWORN TO before me by Ralph L. Luciani on this the 26th day of January, 2010.

Christine McCaffrey

Notary Public, District of Columbia
My Commission Expires October 14, 2012

CHRISTINE McCAFFREY
NOTARY PUBLIC
DISTRICT OF COLUMBIA
My Commission Expires
October 14, 2012

CHRISTINE McCAFFREY • NOTARY PUBLIC • DISTRICT OF COLUMBIA

RALPH L. LUCIANI

Vice President
CRA International

M.S. Industrial Administration, Carnegie Mellon University

B.S. Electrical Engineering and Economics, Carnegie Mellon University

Mr. Luciani has more than 20 years of consulting experience analyzing economic and financial issues affecting regulated industries. He has had a special focus on the electricity industry, where he has assisted electric utilities and generating companies with business planning and restructuring, merger and acquisition analysis, resource planning, power solicitations, ratemaking, fuel and power supply contract negotiations, and environmental compliance strategy.

Mr. Luciani has assisted clients and their legal counsel in the management of numerous complex litigation matters, including electric utility prudence and rate cases, and assessments of economic damages in commercial disputes. He has assisted many clients in reaching agreements in settlement processes administered by the Federal Energy Regulatory Commission (FERC). He has appeared as an expert witness in a number of regulatory proceedings.

Prior to joining CRA, Mr. Luciani was a Senior Vice President at PHB Hagler Bailly, and a Director at Putnam, Hayes & Bartlett, Inc. Before that, he worked as an Edison engineer for the General Electric Company and as a financial analyst for IBM Corporation. Summarized below are a number of recent projects directed by Mr. Luciani involving the electric utility industry.

PROFESSIONAL EXPERIENCE

Generation and Power Marketing

Wind/Transmission Cost-Benefit Study—In 2008, Mr. Luciani led a study team analyzing the economics of installing 1200 miles of 765 kV transmission and 14 GW of new wind power in the Southwest Power Pool. The study examined production and capital costs as well as carbon emission impacts. He presented the results of the study to the SPP Regional State Committee, and the study was filed at the FERC as part of an incentive rate filing.

IRP Development—In 2008, he assisted a utility in developing an integrated resource plan that takes into account in the resource plan modeling uncertainties associated with carbon regulation, gas prices, load growth, supply and demand technology improvements and other items.

Power Solicitations—Mr. Luciani has assisted electric utilities in a number of solicitations for power, including formulating the RFP, conducting bidder's conferences, negotiating term sheets and definitive agreements, and obtaining regulatory approval for the final agreements.

Generation Valuation Lecturer—Over a five-year period, Mr. Luciani served as the lead lecturer and instructor of an advanced training course on generation valuation under cost-of-service rates and under market-based pricing offered annually at a large U.S. investor-owned utility.

Power Marketing—He prepared several affidavits at FERC analyzing the profitability of wholesale trading activities of power marketers.

Cost-Based Wholesale Rates—Mr. Luciani has filed affidavits at FERC developing utility cost-based rates for wholesale sales of capacity and energy in the utility control area.

Stranded Cost Derivation—Mr. Luciani presented testimony before four state utility commissions on the quantification of the stranded cost associated with the deregulation of generation.

Nuclear Plant Sale—Mr. Luciani acted as the lead economic consultant in negotiating the sale of a utility's nuclear plant, including conducting detailed economic analyses of the various offers for the facility and assessing the complex income tax effects that would result from the sale.

Climate Change Regulation—He has assisted several utilities in analyzing the impact of potential climate change regulations on generation resource plans.

RTOs and Transmission

RTO Cost Benefit Studies—He developed the financial models used to derive the economic and rate impacts to stakeholders in five major cost-benefit studies of Regional Transmission Organizations (RTOs), and has provided related testimony in a number of state proceedings.

RTO Administrative Costs and Rates—Mr. Luciani worked as the lead consultant on behalf of the PJM Finance Committee in the FERC settlement process in which PJM proposed the establishment of a stated rate for the recovery of its administrative costs in place of the existing formula rate.

Transmission Ratemaking—Mr. Luciani filed testimony which developed OATT transmission and ancillary service rates for a major G&T electric cooperative and presented testimony before the FERC regarding calculations of earned returns for transmission operations.

Transmission Costing—He provided testimony and negotiated settlement agreements in a FERC settlement process regarding the assignment of costs for through and out transmission charges.

Transmission Expansion—Mr. Luciani assisted a utility in formulating pricing alternatives for the installation of a new 500 kV transmission line to be used primarily to export power.

Financial Evaluation

Cost of Capital—He has testified before the U.S. Bankruptcy Court and assisted counsel in a number of arbitration proceedings regarding the proper discount rate to apply in assessing termination payments for wholesale power contracts, and has assisted counsel in assessing capital structures and rates for use in FERC proceedings.

Municipalization—He assisted an electric utility in deriving the exit charges to be assessed for a proposed municipalization of a portion of the electric utility's service territory.

Mergers and Acquisitions—On several occasions, Mr. Luciani analyzed the potential acquisition of electric utilities and formulated transmission and distribution pro forma financials.

Organizational Restructuring—Mr. Luciani acted as the lead facilitator in a 12-month project that functionally unbundled the operation of an integrated electric utility into stand-alone profit centers.

Distribution and Retail

Distribution Performance-Based Rates—Mr. Luciani formulated a performance-based ratemaking (PBR) plan, for an electric utility, and presented the plan to the state public utility commission.

Distribution Benchmarking—He formulated a benchmarking analysis to compare the costs and rates for the distribution system of an electric utility to the systems of neighboring utilities.

Distribution Cost Allocation—Mr. Luciani filed an affidavit in Ontario, Canada regarding allocation of distribution costs and derivation of stand-by rates for load displacement generation.

Retail Market Strategy—Mr. Luciani formulated an evaluation model to assess the profitability of new retail loads in a competitive market. Mr. Luciani also developed a financial model for a company offering a product to reduce on-peak demand in residences.

Environmental and Fuel

Environmental Regulations—He has assisted electric utilities in formulating strategies for meeting provisions of the Clean Air Act regarding SO_2, NO_x and mercury emissions, and in assessing potential climate change regulations.

Fuel Supply—Mr. Luciani assisted an electric utility in negotiating the terms of a buyout and replacement of a long-term coal supply contract, and in obtaining approval for the rate treatment.

Nuclear Spent Fuel—He assisted counsel in a litigation involving the responsibility for costs incurred in the management of nuclear spent fuel storage and disposal.

Natural Gas—He assisted counsel in obtaining state and federal approval for the merger of natural gas distribution companies, and in evaluating natural gas market manipulation in California.

Expert Testimony Experience

Mr. Luciani has testified before the Arkansas, Kansas, Kentucky, Louisiana, Maryland, Missouri, Ohio, and Pennsylvania public utility commissions, the Ontario Energy Board, the U.S. Bankruptcy Court, and the Federal Energy Regulatory Commission (FERC). On a number of occasions, he has also provided expert testimony on behalf of United Parcel Service (UPS) in U.S. Postal Service rate proceedings before the U.S. Postal Rate Commission.

GE MAPS MODELING ASSUMPTIONS

Summarized below are the key inputs to the GE MAPS locational price forecasting model. As formulated for this study, the model's geographic footprint encompasses the U.S. portion of the Eastern Interconnect with the major focus being on the Big Rivers Electric Cooperative, the Midwest Independent System Operator (Midwest ISO)/Tennessee Valley Authority (TVA) footprint and surrounding regions. The GE MAPS simulations were run for the years 2011 and 2014. Two scenarios were analyzed: 1) Big Rivers stand-alone and 2) Big Rivers as a member of the Midwest ISO.

Primary data sources for the GE MAPS model include the NERC Multiregional Modeling Working Group (MMWG), the General Electric generation and transmission databases for the Eastern Interconnect, the NERC Electricity Supply and Demand (ES&D) database, NERC regions and Independent System Operators/Regional Transmission Organizations, FERC submissions by generation and transmission owners, and CRA analysis of plant operations and market data. Major data components are listed below.

All financial assumptions specified in this document are expressed in real 2008 US dollars, unless otherwise noted.

1 TRANSMISSION

The CRA model is based on load flow cases provided by the NERC MMWG. This analysis uses the modified MMWG 2005 series load flow case for the summer of 2010. The MMWG load flow case encompasses the entire Eastern Interconnect system, including lines, transformers, phase shifters, and DC ties. CRA further analyzed the original load flow against regional transmission planning documents and a number of changes were made to the load flow to reflect future transmission projects (those under construction or having a high probability to be implemented, but not included in the original MMWG models). These include the addition of the Cross-Sound and Neptune high voltage DC cables, the Linden VFT, and various updates in the PJM region.

Reducing the number of constraints monitored in the study reduces the time required for GE MAPS to solve the optimal commitment and dispatch. Therefore, CRA filters out non-significant constraints far away from the study areas to speed up the process. In this study, all non-duplicate constraints from the above sources within Midwest ISO, TVA and western PJM regions are included. For other study areas, a constraint is included only if it has been binding in our previous studies, it represents a major interface or it monitors facilities at 500KV or above.

2 LOAD INPUTS

For each load serving entity, GE MAPS requires an hourly load shape and an annual forecast of peak load and total energy. CRA uses the latest FERC-714 load forecast data available (2009) for each company where available. Ontario data is drawn from the 10-Year Outlook: Ontario Demand Report published by the Independent Electricity Market Operator of Ontario.

Load shapes are drawn from hourly actual demand for 2006, as published in FERC Form 714 submissions and on the websites of various Independent System Operators (ISOs) and NERC reliability regions. These hourly load shapes, combined with forecasts for peak load and annual energy for each company, are used by GE MAPS to develop a complete load shape by company for each forecast year.

3 THERMAL UNIT CHARACTERISTICS

GE MAPS includes a detailed model of thermal generation, in order to accurately simulate operational characteristics, and project realistic hourly dispatch and prices. Modeled characteristics include unit type, unit fuel type, heat rate values and shape (based on unit technology), summer and winter capacities, fixed and variable non-fuel operation and maintenance costs, startup fuel usage, forced and planned outage rates, minimum up and down times, and quick start and spinning reserve capabilities.[1]

The CRA generation database reflects unit-specific data for each unit based on a wide variety of sources. In cases where unit-specific data is not available, representative values based on unit type, fuel and size are used. Table 1 and Table 2 document these generic assumptions.

Table 1: Generic Characteristics for Thermal Units, Part 1

Unit Type and Size	Variable O&M ($/MWh)	Fixed O&M ($/kW-year)	Minimum Uptime (hours)	Minimum Downtime (hours)	Heat Rate Shape
Combined Cycle	$ 2.50	$ 21.00	6	8	4 blocks: 50% capacity at 113% FLHR, 67% capacity @ 75% FLHR, 83% capacity @ 86% FLHR, and 100% capacity @ 100% FLHR
Combustion Turbine (<50MW) [*1]	$ 10.00	$ 10.00	1	1	Single block, 100% capacity at 100% FLHR
Combustion Turbine (50MW<) [*1]			1	1	
Steam Turbine Coal (<100MW)	$ 5.00	$ 35.00	24	12	3 blocks: 50% capacity at 106% FLHR, 75% capacity @ 90% FLHR, and 100% capacity @ 100% FLHR
Steam Turbine Coal (100MW<200MW)	$ 4.00				
Steam Turbine Coal (200MW<600MW)	$ 3.00				
Steam Turbine Coal (600MW<) [*2 *3]	$ 2.00				
Steam Turbine Gas/Oil (<100MW)	$ 6.00		10	8	4 blocks: 30% capacity at 110% FLHR, 50% capacity @ 90% FLHR, 75% capacity @ 96% FLHR,and 100% capacity @ 100% FLHR
Steam Turbine Gas/Oil (100MW<200MW)	$ 5.00				
Steam Turbine Gas/Oil (200MW<600MW)	$ 4.00				
Steam Turbine Gas/Oil (600MW<) [*4]	$ 3.00				

*1 Includes start up cost
*2 Min Up / Min Down will be 16/8 for newer sliding pressure super critical units.
*3 Heat rate shapes will be 4 blocks: 30% capacity at 110% FLHR, 50% capacity @ 93% FLHR, 75% capacity @ 95% FLHR, and 100% capacity @ 100% FLHR for newer sliding pressure super critical units.
*4 Heat rate shapes will be 4 blocks: 20% capacity at 110% FLHR, 50% capacity @ 95% FLHR, 75% capacity @ 98% FLHR, and 100% capacity @ 100% FLHR for newer sliding pressure super critical units.

[1] Note that certain data types are specified on a plant-specific basis in CRA's database and therefore do not require corresponding generic data. These include but are not limited to summer/winter capacity, full load heat rates and emissions data.

Table 2: Generic Characteristics for Thermal Units, Part 2

Unit Type and Size	Forced Outage Rate (%)	Planned Outage Rate (%)	Typical Forced Outage Length (Days)
Combined Cycle	1.75%	7.78%	2
Combustion Turbine (<50MW)	2.46%	4.92%	1
Combustion Turbine (50MW<)	2.49%	6.66%	1
Steam Turbine Coal (<100MW)	3.32%	8.73%	7
Steam Turbine Coal (100MW<200MW)	3.93%	8.26%	7
Steam Turbine Coal (200MW<600MW)	4.36%	9.20%	7
Steam Turbine Coal (600MW<)	4.36%	9.20%	7
Steam Turbine Gas/Oil (<100MW)	2.35%	6.78%	2
Steam Turbine Gas/Oil (100MW<200MW)	3.14%	11.96%	2
Steam Turbine Gas/Oil (200MW<600MW)	3.05%	13.01%	2
Steam Turbine Gas/Oil (600MW<)	3.03%	14.97%	2

The primary data source for generation units and characteristics is the NERC Electricity, Supply and Demand (ES&D) 2006 database, which contains unit type, fuel type (primary and secondary), and capacity data for existing units. Heat rate data is drawn from prior ES&D databases where available. For newer plants, heat rates are based on industry averages for the technology of the unit. The NERC Generation Availability Data System (GADS) 2003 database, released January 2005, is the source for forced and planned outage rates, based on plant type, size, and vintage. Fixed and variable operation and maintenance costs are estimates based on plant size, technology, and age. These estimates are supplemented by FERC Form 1 submissions where available. The fixed O&M values include an estimate of $1.50/kW-yr for insurance and 10% of base fixed O&M (before insurance) for capital improvements.

Plants that are known to be cogeneration facilities are either modeled with a low heat rate (6000 Btu/kWh), or set as must-run units in the dispatch, to reflect the fact that steam demand requires operation of the plant even when uneconomical in the electricity market.

4 Nuclear Units

CRA assumes that nuclear plants run when available, and that they have minimum up and down times of one week. Forced outage rates for each unit are drawn from the Energy Central database of unit outages. Nuclear plants do not contribute to quick-start or spinning reserves. The model includes refueling and maintenance outages for each nuclear plant. Outages in the near future posted on the NRC website or announced in the trade press are included. For later years, refueling outages are projected on the basis of the refueling cycle, typical outage length, and last known outage dates of each plant. Since these facilities are treated as must run units, CRA does not specifically model their cost structure. Within the timeframe of this study, no nuclear retirements are applied, since it is likely that most current plants will obtain extensions to their operating licenses.

5 HYDRO UNITS

GE MAPS has special provisions for modeling hydro units, and requires specification of a monthly pattern of water flow, i.e. the minimum and maximum generating capability and the total energy for each plant. Plant capacity data is drawn from the NERC ES&D database. Plant monthly energy data is drawn from an average of Form EIA-860 submissions for 1992-1998. CRA assumes that the plant is able to provide spinning reserves of up to 50% of plant capacity.[2]

6 RENEWABLE RESOURCES

Individual existing wind resources were modeled either as low-cost ($1/MWh) dispatchable energy resources based on the hourly profiles from 2006 (for wind within the focused area), or with a fixed annual capacity factor of 30% (for wind located far from the focused area). Solar generators (photovoltaic units) are run at 24% annual capacity factor, and restricted to daytime hours.

7 CAPACITY ADDITIONS AND RETIREMENTS

CRA adds new generation based on projects in development or advanced stages of permitting, as indicated by trade press announcements, trade publications, environmental permit applications, and internal knowledge. CRA also adds generic capacity where economically justified, or as required to maintain resource adequacy per installed capacity reserve margins published by various NERC regions. CRA tracks planned and announced retirements from power pool publications and trade press announcements, and will retire units accordingly with the exception of nuclear units.

8 ENVIRONMENTAL REGULATIONS

For thermal generating units, variable operating and maintenance costs associated with installed scrubbers (SO_2 reduction) or with Selective Catalytic Reduction (SCR) processes for NO_x reduction are included in the marginal production cost and the unit energy bids. No fixed or capital costs of these emission control technologies are included in the calculation of marginal cost. CRA tracks industry announcements of units that are planning to install NO_x or SO_2 abatement technologies in the near future and models the resulting changes in emission rates and the variable and fixed costs associated with the new installations.

To account for SO_2 trading under EPA's Acid Rain Program, the model incorporates the opportunity cost of SO_2 tradable permits into the marginal cost bids, based on unit emission rates and forecast allowance trading prices for the time period of the simulation. NO_x emission rates are drawn from the CEMS data filed with the US Environmental Protection Agency. Emission allowance prices for NOx and SO_2 are based on market data from Evolution Market brokerage. CRA modeled NO_x and SO2 allowances based on the Clean Air Interstate Rule (CAIR),[3] and CO2 emission based on the Regional Greenhouse Gas Initiative (RGGI) for northeastern states only. Given the current status of the Clean Air Mercury Rule (CAMR), no mercury emissions were modeled. Emission allowance prices for NO_x and SO_2 are based on market data from Evolution Market brokerage.

---

2 For example, if a plant with 100MW capacity was generating 60MW at a given hour, it can provide up to 20MW [(100 – 60) / 2] of spin for that hour.

3 CAIR requires participating states to submit two allowances per ton of SO_2 emission, rather than one allowance as per the Title IV Acid Rain Program. CAIR states are most states east of MN, IA, MO, AR, LA and TX.

9 External Region Supply

CRA explicitly models the US portion of the Eastern Interconnect and the Canadian provinces of Ontario, Manitoba and Saskatchewan. Regions outside this study area are modeled as either supply profiles or scheduled interchanges. CRA uses historic flows, combined with expectations of future conditions in these areas to project quantities and prices of power exchanged with the model footprint. In this analysis, flows from New Brunswick to New England, and from Hydro Quebec to Ontario are modeled as scheduled flows, based on 12 months of historical data. Flows from Hydro Quebec to New York and New England are modeled as price sensitive supply curves.

The DC ties with the WECC and ERCOT interconnections are modeled as price sensitive supply curves. CRA uses historical electricity prices and gas prices near these DC ties to calculate implied market heat rates[4] for on-peak and off-peak periods.

10 Dispatchable Demand (Interruptible Load)

The presence of demand response is important to energy and installed capacity prices. The value of energy to interruptible loads caps the energy prices, and the capacity of interruptible load effectively replaces installed reserves and lowers the capacity value. CRA uses values for interruptible load, and demand side management reduction in peak for Florida from the NERC ES&D database. This interruptible load is spread among load areas based on their load share of the total system load. The dispatchable demand is implemented as generators with a dispatch price of $600/MWh for the first block (50% of area dispatchable demand) and $800/MWh for the second block. These units rarely run, as the high prices they require indicate a supply shortfall and prompt economic new entry. Thus, they play an insignificant role in the energy market, but they play an important role in the capacity market. If these loads can be interrupted during peak hours, they will be paid the capacity market-clearing price. Thus, they have strong incentives to make themselves available during peak hours. When interruptible demand is included in the calculation of the required reserve margin, it reduces the requirement of installed capacity and thus reduces new entry and helps increase energy prices, consistent with market behavior.

11 Market Model Assumptions

Marginal Cost Bidding. All generation units are assumed to bid marginal cost (opportunity cost of fuel plus non-fuel VOM plus opportunity cost of tradable emissions permits). To the extent that markets are not perfectly competitive, the modeling results will reflect the lower bound on prices expected in the actual markets.

Operating Reserves Requirement (spinning reserves). Operating reserves are based on requirements instituted by each reliability region. These requirements are based on the loss of the largest single generator, or the largest single generator and half the second largest generator, or a percentage of peak demand. The spinning reserves market affects energy prices, since units that spin cannot produce electricity under normal conditions. Energy prices are higher when reserves markets are modeled.

---

4 Implied market heat rate is calculated as electricity prices ($/MWh) divided by natural gas prices ($/MMBtu) and thus assumes natural gas to be the marginal fuel. Thus, if electricity prices were $72/MWh and natural gas prices were $9/MMBtu, the implied heat rate would be 8000 Btu/kWh.

In modeling supply for operating reserves, the spinning capabilities of generating units are specified on a unit type basis. For spinning reserves, the maximum level of spinning reserve capability of a thermal unit is set as a lesser of the unit's ramp rate (in MW/min) times 10 (reserves supplied within 10 minutes) and its capacity above minimum block. Assumed ramp rates are: 10 MW/min for combine cycle units, 6 MW/min for gas and oil steam units, 3 MW/min for coal units. For hydro plants, spinning reserve capability is set on a monthly basis at 50% of the difference between plant's capacity in that month and its average for that month hourly output. No spinning capability was assigned to nuclear generators.

With respect to the two scenarios conducted in GE MAPS, for the Stand-alone Case, 100% of the largest contingency, the DB Wilson 417 MW coal unit, is required to be held as Contingency Reserve by Big Rivers. From this requirement, 200 MW of assumed contracted aluminum smelter capacity and/or new peaking capacity and 65 MW of capacity from Reid CT were subtracted. The remaining 152 MW becomes the required reserve requirement from the Big Rivers coal units, and were modeled using unit ramp rate data supplied by Big Rivers. In the Midwest ISO Case, the Big Rivers reserve requirement, 32 MW, is taken from the former Midwest Contingency Reserve Sharing Group Agreement.

For both study years, First Energy is assumed to leave the Midwest ISO, however, the largest contingency in the Midwest ISO remains the DC tie with Manitoba. To account for First Energy leaving the Midwest ISO, the requirement for each remaining member is scaled up in proportion to their current contribution. For the Stand Alone scenario, the reserve requirement for each remaining member is again scaled proportionally.

Transmission Losses. Transmission losses are modeled at marginal rates over the entire Eastern Interconnection.

12 Seams Charges and Transmission (Wheeling) Rates

Seams charges are "per MWh" charges for moving energy from one control area to another in an electric system. In GE MAPS, seams charges are applied to net interregional power flows and are used by the optimization engine in determining the most economically efficient dispatch of generating resources to meet load in each model hour. The commitment process is performed in GE MAPS for a defined set of major pools in the Eastern Interconnection. Within these pools, there can be commitment seams charge between control areas to reflect that the commitment process is not performed on a fully integrated basis within that pool. The seams charge modeled for dispatch includes both wheeling rates from tariffs and a second value, which is referred to as friction, representing the impediments to trade between control areas that take place on a real-time basis.

Table 3 gives an overview of the seams charges between Big Rivers (BREC), MISO, TVA and other neighboring control areas used for this study. As shown, in the Stand-alone Case, Big Rivers is committed within the LG&E/EKPC/BREC pool, with a commitment seams charge and dispatch seams charge between each of these three entities. In the Midwest ISO Case, Big Rivers becomes part of the Midwest ISO and is committed jointly with the Midwest ISO, with no dispatch seams charge between Big Rivers and the rest of the Midwest ISO, and Midwest ISO dispatch seams charges applying between Big Rivers and non-Midwest ISO entities.

Table 3: Seams Charges ($/MWh)

	From Commitment Pool	To Commitment Pool	Dispatch Seams Charge Wheel	Friction*	Total
	Day 2:				
1	MISO***	PJM	0	2	2
	MISO	All Other	5	3	8
2	PJM	MISO	0	2	2
	PJM	All Other	3	3	6
3	SPP **	All	2	3	5
4	NE	NY	0	3	3
	NE	All but NY	7	3	10
5	NY	NE	0	3	3
	NY	HQ	2	3	5
	NY	OH	4	3	7
	NY	PJM	5	3	8
	Non-Day 2:				
6	AECI	All	3	5	8
7	VACAR-Duke/CPL	All	2	5	7
8	Entergy	All	3	5	8
9	FRCC	All	3	5	8
10	KY	All		*See Below*	
11	SOCO	All	5	5	10
12	TVA	All	3	5	8
13	OH	All	1	5	6
14	HQ	All	8	5	13
15	NB/Maritimes	All	3	5	8

Intra-Commitment Pool Seams Charges

From	To	Dispatch Seams Charge Wheel	Friction*	Total	Commitment Seams Charge
Cleco Power	*SPP*	3	3	6	10
SPP	*Cleco Power*	2	3	5	10
Cleco Power	*Entergy*	3	5	8	NA
Intra-FRCC	*Intra-FRCC*	3	5	8	10
Duke/CPL/SCG	*Duke/CPL/SCG*	2	5	7	10
NWE	*MISO*	4	3	7	10
NWE	*WAPA*	4	5	9	10
WAPA	*MISO*	4	3	7	10
WAPA	*NWE*	4	5	9	10
MISO	*NWE/WAPA*	5	3	8	10
MISO	*SASK*	5	3	8	10
SASK	*MISO*	6	5	11	10
Intra-Maritimes	*Intra-Maritimes*	3	5	8	10
BIG RIVERS STAND-ALONE CASE:					
LG&E	*BREC & EKPC*				10
BREC	*LG&E & EKPC*				10
EKPC	*LG&E & BREC*				10
LG&E	*All*	2	5	7	
BREC	*All*	3	5	8	
EKPC	*All*	5	5	10	
BIG RIVERS MIDWEST ISO CASE:					
LG&E	*EKPC*				10
EKPC	*LG&E*				10
LG&E	*All*	2	5	7	
EKPC	*All*	5	5	10	

** $3 dispatch friction hurdle for flows out of active managed markets*
** Non market areas not expected to be as efficient hence higher dispatch friction of $5*
** Average of on- and off-peak non-firm hourly rate used in addition to friction*
** PJM to/from MISO friction set at $2 given extensive seams management process*
*** Day 2 planned*
**** Includes BREC in Midwest ISO Case*

13 Fuel Prices

GE-MAPS uses monthly fuel prices for each thermal unit. The fundamental assumption of behavior in competitive markets is that generators will bid their marginal cost into the energy market. The marginal cost for a gas plant is the opportunity cost of fuel purchased (in addition to non-fuel variable O&M and environmental adders), or the spot price of gas at the location closest to the plant. CRA therefore uses forecasts of spot prices at regional hubs, and refines these on the basis of historical differentials between price points and their associated hubs. For fuel oil, CRA uses estimates of the price delivered to generators on a regional basis.

The coal price forecast are developed by the CRA NEEM model, which is described in a following section. Table 4 shows the NEEM produced coal prices for plants in the Big Rivers footprint.

Nuclear plants are assumed to run whenever available, so nuclear fuel prices do not impact commitment and dispatch decisions in the market simulation model. CRA therefore does not do a detailed analysis of nuclear fuel prices.

Specific oil and gas price forecasts proposed to be used in this study are provided in the next section. They take into account NYMEX futures prices from June 6, 2009.

Table 4: Coal Prices for Big Rivers Units

Unit Name	2011 ($/MMBtu)	2014 ($/MMBtu)
Coleman 1	2.94	2.81
Coleman 2	2.94	2.81
Coleman 3	2.94	2.89
D.B. Wilson	2.00	1.93
Green 1	2.15	2.08
Green 2	2.15	2.08
Reid	2.96	2.97
HMP&L Station 1	2.94	2.89
HMP&L Station 2	2.94	2.89

14 Natural Gas and Fuel Oil Price Forecast

14.1 Natural Gas Forecast

Principal Drivers: The principal drivers are the projected prices for natural gas at Henry Hub. Base Case Forecast: For both study years the Base Case forecast is set equal to NYMEX futures prices for natural gas at Henry Hub

Regional Prices: CRA forecasts natural gas prices on a regional basis following major pipeline traded pricing points. Regional forecasts are derived by adding two factors, the basis differential by region and local delivery charge by state, to the Henry Hub gas price.

Basis Differentials by Region: CRA recognizes multiple pricing points within each census region, all of which are actual pipeline trading points surveyed and reported by Platt's Gas Daily. Some of these pricing points coincide with the NYMEX Clearport hubs, which include Henry Hub. For the other points, CRA uses a regression model to one or several NYMEX Clearport hubs, calibrated with historical data, to derive a forecast. The NYMEX Clearport hub futures settlement data are only available for a short period, typically between 12 and 24 months. Within this time frame, CRA derives monthly differentials to these hubs using NYMEX data. Beyond this period, CRA scales the basis differentials in proportion to the Henry Hub forecast. Forecast prices at each hub are derived using the Henry Hub forecast and the scaled basis differential for that hub. The pricing points used and their relation to the NYMEX Clearport futures are shown in Table 5.

Local Delivery Charges: Burner tip prices for natural gas are the sum of the basis differentials by region as derived above and a local component that captures pipeline lateral charges and/or charges to local distribution companies. CRA estimates this local component at $0.07/MMBtu for all units. For older units CRA estimates extra LDC charges derived from AGA statistics.

Seasonal Pattern: Natural gas prices are varied seasonally based on NYMEX futures data in the near term. In the long term, the seasonal pattern for the last available year is repeated for each year.

Table 5: NYMEX Clearport Hubs used for Natural Gas Forecast

Region	States	Natural Gas Pricing Point	Weights	Deriving Source - Summer (NYMEX Clearport hubs)
Eastern New York	NY (East)	Transco Zone 6 (NYC)	1	Direct NYMEX Clearport Hub
Western New York	NY (West)	Dominion (Appalachia)	0.5	Direct NYMEX Clearport Hub
		Iroquois	0.5	Regressed to Michigan and Transco Zone 6 NYC
PJM	MD, NJ, PA (East)	Tennessee Zone 6	0.5	Direct NYMEX Clearport Hub
		Dracut	0.5	Regressed to Texas Eastern Zone M 3 and Transco Zone 6 NYC
Appalachia	KY, OH, PA (West), WV	Columbia Gas Appalachia	0.25	Direct NYMEX Clearport Hub
		Leidy Hub	0.25	Regressed to Transco Zone 6 NYC
		Dominion (Appalachia)	0.5	Direct NYMEX Clearport Hub
Southern New England	CT, MA, RI	Algonquin City Gates	1	Regressed to Transco Zone 6 NYC
Northern New England	ME, NH, VT	Tennessee Zone 6	0.5	Regressed to Texas Eastern Zone M 3 and Transco Zone 6 NYC
		Dracut	0.5	Regressed to Dominion (Appalachia)
Iowa-Missouri-Nebraska	IA, MO, NE	Ventura	1	Direct NYMEX Clearport Hub
Florida	FL	Florida CityGate	1	Direct NYMEX Clearport Hub
Mid-Continent	KS, OK	NGPL Mid-Continent Basis	1	Direct NYMEX Clearport Hub
Midwest	IL, IN, MI, MN, ND, SD, WI	Chicago Basis	0.5	Direct NYMEX Clearport Hub
		Michigan Basis	0.5	Direct NYMEX Clearport Hub
Ontario-East	ON (East)	Niagara	1	Regressed to Dominion (Appalachia) and Michigan Basis
Ontario-West	ON (West)	Dawn, Ontario	1	Regressed to Michigan Basis
South Atlantic East	DC, DE, GA, NC, SC, VA	Texas Eastern Zone M-3	0.167	Direct NYMEX Clearport Hub
		Transco Zone 6 Non-NYC	0.167	Regressed to Transco Zone 6 NYC
		Transco Zone 4	0.167	Regressed to Transco Zone 3
		Texas Eastern Zone M-1	0.167	Regressed to East LA Basis
		Florida Gas Mobile Bay	0.333	Regressed to Transco Zone 3
South Atlantic South	AL, AR, LA, MS, TN	Henry Hub	1	Direct NYMEX Clearport Hub

Table 6: Natural Gas Prices for 2011 and 2014 (2008$/MMBtu)

2011	Newer Units (No LDC)	Older Units (With LDC)
Month	KY	KY
Jan	$ 6.82	$ 7.48
Feb	$ 6.81	$ 7.47
Mar	$ 6.60	$ 7.26
Apr	$ 6.11	$ 6.77
May	$ 6.07	$ 6.73
Jun	$ 6.14	$ 6.79
Jul	$ 6.21	$ 6.87
Aug	$ 6.27	$ 6.92
Sep	$ 6.29	$ 6.94
Oct	$ 6.36	$ 7.01
Nov	$ 6.58	$ 7.24
Dec	$ 6.87	$ 7.52
Annual Average	$ 6.43	$ 7.08

2014	Newer Units (No LDC)	Older Units (With LDC)
Month	KY	KY
Jan	$ 7.04	$ 7.67
Feb	$ 7.02	$ 7.65
Mar	$ 6.78	$ 7.40
Apr	$ 6.12	$ 6.74
May	$ 6.07	$ 6.69
Jun	$ 6.13	$ 6.75
Jul	$ 6.21	$ 6.83
Aug	$ 6.26	$ 6.88
Sep	$ 6.28	$ 6.89
Oct	$ 6.34	$ 6.96
Nov	$ 6.56	$ 7.17
Dec	$ 6.82	$ 7.43
Annual Average	$ 6.47	$ 7.09

14.2 Fuel Oil Price Forecast

Principal Drivers: The principal drivers underlying this forecast are the projected price for light sweet crude oil at Cushing, Oklahoma.

Base Case Forecast: For both study years the Base Case forecast is derived from the NYMEX futures prices for light sweet crude oil.

Regional Prices: CRA forecasts prices for fuel oil #2 and #6 by US census region. This forecast is prepared in two steps. First CRA uses a regression model calibrated on historical data to derive prices for fuel oil #2 and #6 at New York Harbor from the forecast of crude oil prices. Second, we apply historical basis multipliers for each census regions against the mid-Atlantic Census region (includes New York Harbor)

Seasonal Pattern: Both fuel oil #2 and fuel oil #6 prices are varied monthly based on NYMEX futures data in the near term, and based on historical monthly patterns in the longer term.

The fuel oil forecast prices for Big Rivers is shown in Table 7.

Table 7: Fuel Oil Prices for 2011 and 2014 (2008$/MMBtu)

2011	FO6	FO2
Month	KY	KY
Jan	$ 6.38	$ 15.11
Feb	$ 6.39	$ 15.12
Mar	$ 6.39	$ 15.13
Apr	$ 6.39	$ 15.14
May	$ 6.40	$ 15.15
Jun	$ 6.40	$ 15.16
Jul	$ 6.41	$ 15.17
Aug	$ 6.41	$ 15.18
Sep	$ 6.42	$ 15.19
Oct	$ 6.42	$ 15.19
Nov	$ 6.42	$ 15.20
Dec	$ 6.43	$ 15.21
Annual Average	$ 6.41	$ 15.16

2014	FO6	FO2
Month	KY	KY
Jan	$ 8.62	$ 21.46
Feb	$ 8.63	$ 21.46
Mar	$ 8.63	$ 20.52
Apr	$ 8.63	$ 20.40
May	$ 8.64	$ 19.48
Jun	$ 8.64	$ 19.25
Jul	$ 8.64	$ 19.29
Aug	$ 8.65	$ 19.62
Sep	$ 8.65	$ 20.17
Oct	$ 8.66	$ 20.41
Nov	$ 8.66	$ 20.63
Dec	$ 8.66	$ 20.95
Annual Average	$ 8.64	$ 20.30

15 NEEM FORECAST

Output from CRA's North American Electricity and Environment Model (NEEM) is used to populate the MAPS model's with plant-specific coal price inputs. The NEEM model is a long-term planning model that optimizes fuel and environmental compliance decisions based on the environmental scenario considered. Given that coal-fired generation is the target of many pending and proposed environmental initiatives, the future coal selection at generating stations and quantity of coal consumed nationally is heavily dependent on the scenario modeled and the resultant retrofit decisions, generation levels and new capacity additions. The quantities of coal consumed, by region, are likely to shift over time in response to environmental considerations and that shift will, in-turn, affect coal pricing and fuel choice at generation stations across the United States.

The NEEM model itself is supported by 21 individual supply curves spread across major US coal producing regions and the primary international production areas exporting to the United States. These curves are built up from mine level data on production costs and annual production capability. Each curve shifts over time as a result of the interaction between three effects – resource depletion, new mine development/expansion and changes in mine costs.

Resource depletion and expansion is done at the mine level, changing the shape of each coal type's supply curve over time. For example, lower cost mines may be depleted over time with expansion occurring at the higher end of the cost curve. Such a pattern of depletion and expansion would result in an increase in the weighted average coal costs for a given coal type. Resource depletion is a significant consideration for Central Appalachian production areas and low Btu Northern Appalachian coals where the total available resources decline over time in the NEEM inputs. The most significant production expansion capability is in Northern Appalachian and Illinois Basin high sulfur coals, the Powder River Basin (PRB) and imports.

Changes in mine costs are applied at the supply curve level, allowing for parallel shifts in the costs for each coal type over time. The changes in cost can be viewed as a function of a number of underlying components such as mine productivity and changes in labor or materials and supplies costs. The supply curve structure allows for changes in the relative costs for coal by coal type and region. Costs do not change at the individual mine level. Thus, the costs for coals of a given type exhibit the same pattern of price changes over time.

Table 8 includes the quality parameters associated with each of the 21 coals included in the NEEM model. The NEEM model allows coal-burning units to select a coal based on its quality profile and the delivered price. As demand for a given coal type increase or decreases, its FOB mine price rises or falls consistent with the underlying supply curve. NEEM optimizes coal selection by plant based on power demand and all environmental constraints.

Table 8: Coal Quality Parameters

Description	SO2 (lbs./MMBtu)	Hg (lbs./TBtu)	MMBtu (per Ton)
Northern Appalachia High Btu Low Sulfur	2.47	9.9	25.7
Northern Appalachia High Btu High Sulfur	3.95	11.2	25.8
Northern Appalachia Low Btu Low Sulfur	1.72	14.6	24.2
Northern Appalachia Low Btu High Sulfur	3.42	19.5	23.6
Central Appalachia Compliance	1.12	5.4	25.5
Central Appalachia High Btu Non-Compliance	1.5	7.4	25.3
Central Appalachia Low Btu Non-Compliance	1.8	8.5	24.1
Southern Appalachia	1.97	8	24.4
Illinois Basin - ILBS Hi (High sulfur)	5.2	6.3	22.8
Illinois Basin - ILBS Med (Medium sulfur)	2.8	6.5	22.8
Illinois Basin - ILBS Hi (Low sulfur)	1.7	4.5	22.8
Central Basin	4.82	21.4	24.2
Lignite	2.62	12.8	13.5
Montana Powder River Basin	1.19	5.2	18.1
Northern (WY) Powder River Basin	0.89	7.1	16.8
Central (WY) Powder River Basin	0.75	5.4	17.1
Southern (WY) Powder River	0.65	5.8	17.7
Rocky Mountain Colorado	0.93	3.5	22.9
Rocky Mountain Utah	1.04	4	23.1
Four Corners	1.44	6.1	19.3
Import	0.98	5.2	24

15.1 Transportation Matrices

Not all plants are allowed to select from the full range of coals available in the model. Limitations on coal selection are a function of coal rank (bituminous, subbituminous, lignite) – NEEM requires a capital cost to change from bituminous to subbituminous. Limitations are also a function of transportation access. Coal selection is regulated within the model through a set of plant-specific coal transportation cost matrices that match plants to coals. The matrices are mode specific, barge, rail, truck and mixed mode. The plant/coal-type entries are populated based on the following methodology:

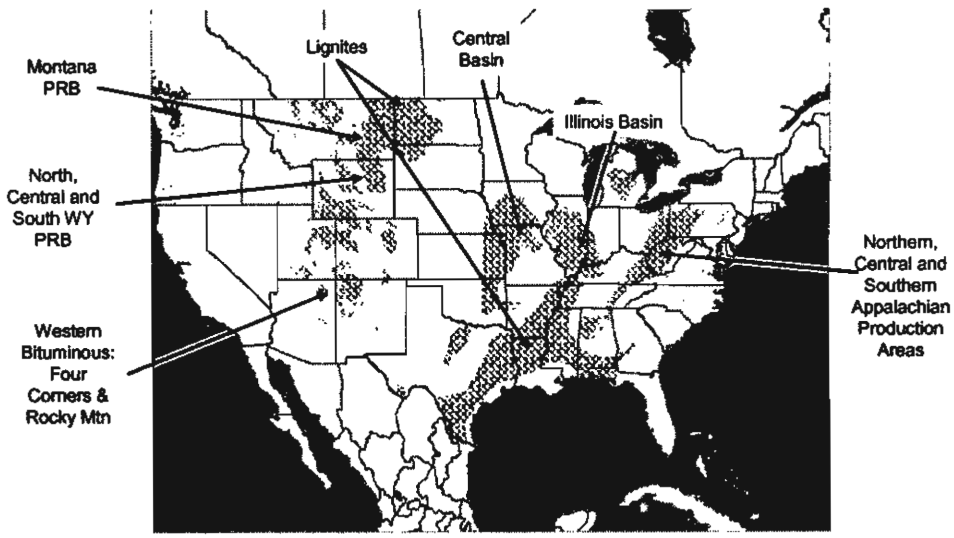
For plants that have selected a given coal in the past, the transportation cost matrix is populated using actual transportation costs for that coal/plant/mode combination.

If a plant has not purchased a given coal in the past but has the physical capability to transport and burn the coal, the transport cost is estimated based on the weighted average delivery cost for the coal-type/NERC region/transport mode combination.

In some limited cases, when no regional data exists, CRA estimated a delivery cost for coal/plant combinations. These cases include increasing the eastern access of PRB and some additional penetration of Illinois Basin coal into the southeast. These cost estimates were developed based on the $/ton-mile cost of long-haul shipments of the coal in question and the distance between the plant and the producing region.

Aside from the PRB and Illinois exceptions noted above, if there is no history of a coal being consumed in a given NERC region, the plants in that NERC region are not allowed to select that coal.

Figure 1: Key Producing Regions in the United States



15.2 NEEM Output

The output from the NEEM model is a revised set of coal choices by the plants in the model, a schedule of environmental retrofit decisions, prices for environmental allowances and a plant-specific delivered coal price for each NEEM unit. Due to the dynamics of the NEEM solution - a multi-year cost optimization given changes in domestic environmental policy – the coals assigned to individual units and used for MAPS inputs may change versus history.

CRA has put the NEEM outputs through an extensive review to ensure that the aggregate coal consumption comports with EIA projections on production capability by coal producing region, historic production levels by coal type and to ensure that the annual changes in coal production by region are feasible. Several input variables, however, have an influence the NEEM solution. Principal among them is the coal availability and pricing/cost in the PRB. The PRB is not constrained by the amount of coal in the ground, but other constraints limit the growth in PRB production and the overall level of production achieved from the basin. Air permit capacity sets a theoretical limit on the amount of coal that can be produced from each of the four PRB regions included.

Table 9: PRB Air Permit Limits

Region	Tons (millions)
Montana	77.0
North Gillette	122.9
South Gillette	168.0
Wright Area	327.0
Total	**694.9**
Total WY	**617.9**

While the air permit considerations may limit the ultimate production out of the basin, these limits have been raised in the past and recent production levels have not come close to challenging these limits. Once production begins to approach the limits, the limits may be expanded or alternatives such as increased paving of roads in the region may be considered to alleviate air quality concerns.

Year to year production in the PRB has achieved a 5.5% CAGR between 1989 and 2005. In order to maintain production growth at that rate, substantial infrastructure investment will be required to improve transport access. Production increases will require WY PRB mining activity further to the west, accessing deeper portions of the Wyodak-Anderson coal zone. In addition, federal bonus bids have been steadily increasing since 1998. All of these factors will put pressure on PRB production costs relative to today.

The Montana PRB production has been relatively static at between 35 and 40 MM tons per year over the period due in large measure to sodium levels, transportation access and production tax rates versus Wyoming PRB. To the extent that Montana production continues to remain static, there will be limits on the ultimate production from the basin as a whole.

Table 3-1
Costs to Serve Big Rivers Load
Stand-alone Case vs. Midwest ISO Case
(Millions of nominal, as-spent dollars)

	2011	2012	2013	2014	2015	Present Value
Stand-alone Case						
+ Production Costs	347.2	352.7	358.3	363.9	373.0	
+ Purchase Costs	58.4	65.4	72.7	80.3	82.3	
- Sales Revenue	7.4	9.5	11.8	14.1	14.5	
= Total	398.2	408.8	419.4	430.1	440.8	
Midwest ISO Case						
+ Production Costs	371.0	376.8	382.7	388.6	398.3	
+ Purchase Costs	29.9	35.8	42.1	48.6	49.8	
- Sales Revenue	13.7	16.2	18.9	21.6	22.1	
= Total	387.2	396.7	406.1	415.6	426.0	
Reduced Cost of Energy Supply in Midwest ISO						
+ Production Cost Savings	(23.9)	(24.2)	(24.4)	(24.7)	(25.3)	(106.5)
+ Purchase Cost Savings	28.6	29.6	30.6	31.7	32.5	132.6
- Sales Revenue	(6.3)	(6.7)	(7.1)	(7.5)	(7.6)	(30.5)
= Total	11.0	12.1	13.3	14.4	14.8	56.7

Table 3-2
Contingency Reserve Available from Big Rivers Coal Units
(excluding D.B. Wilson)

	Capacity MW	Min Load MW	Max Swing MW	Ramp Rates MW/min Up	Ramp Rates MW/min Down	Max Swing in 10 min (MW)
HMPL 1	153	128	25	3	3	25
HMPL 2	159	127	32	3	3	30
Coleman 1	145	110	35	3	3	30
Coleman 2	145	100	45	3	3	30
Coleman 3	151	120	31	3	3	30
Reid Steam	50	33	17	2	2	17
Green 1	231	162	69	3	3	30
Green 2	223	161	62	3	3	30
Total	1,257	941	316			222

Table 3-3
Calculation of Administrative and Other Costs
(Millions of nominal, as-spent dollars)

	2011	2012	2013	2014	2015	PV 1/1/2011
Big Rivers Administrative Charges in Midwest ISO						
BREC Energy for Load (GWh) (a)	12,215	12,188	12,240	12,290	12,346	
Midwest ISO Admin Charges ($/MWh) (b)						
Schedule 10	0.151	0.146	0.137	0.143	0.147	
Schedule 16	0.025	0.019	0.018	0.018	0.018	
Schedule 17	0.197	0.170	0.160	0.160	0.164	
Total	0.373	0.335	0.315	0.321	0.329	
Big Rivers Midwest ISO Admin Fees (M$)	4.6	4.1	3.9	3.9	4.1	17.9
Big Rivers FERC Charges in Midwest ISO						
BREC Energy for Load (GWh) (a)	12,215	12,188	12,240	12,290	12,346	
Midwest ISO FERC Fees ($/MWh) (c)	0.055	0.056	0.057	0.059	0.060	
Big Rivers FERC Fees in Midwest ISO (M$)	0.67	0.68	0.70	0.72	0.75	3.1
Standalone Capacity/Demand Purchases						
Amount Purchased (MW)	200	200	200	200	200	
Cost ($/kW-year) (d)	110.1	112.9	115.7	118.6	121.5	
Cost (M$)	22.0	22.6	23.1	23.7	24.3	100.5
Big Rivers Midwest ISO Interface Costs (e)	0.76	0.77	0.79	0.81	0.83	3.44

(a) BREC FERC Form 714
(b) Midwest ISO Five Year Forecast 2010-2012 Budget; midwestiso.org/documents/financial & credit information/budgets & forecasts
(c) Sch. 10 FERC Rate for 2009_2010.pdf; midwestiso.org/documents/cost recovery adder/2009 midwest ISO rates Estimated FERC Charge for FY2010 divided by Schedule 10 Energy MWh from (b), thereafter escalated at inflation
(d) PJM RPM Cone and E&AS Values for 2012/2013 Base Residual Auction, Based on FERC Order of 3-26-09 RTO-wide Levelized Revenue Requirement for 2012, adjusted for inflation for other years
(e) Western Farmers Data from CRA SPP Cost Benefits Analysis, Appendix 4-2 and 4-3

Table 3-4
Costs to Serve Big Rivers Load
Stand-alone Case vs. Midwest ISO Case

	2011			2014		
Generation (GWh)						
	Stand Alone	**in-MISO**	**Increase**	**Stand Alone**	**in-MISO**	**Increase**
Coleman 1	838	964	126	849	1,019	170
Coleman 2	831	948	117	831	976	145
Coleman 3	853	963	110	856	935	78
Wilson	3,068	3,086	17	3,065	3,086	21
Green 1	1,624	1,743	119	1,619	1,706	87
Green 2	1,609	1,699	90	1,613	1,663	49
Reid Steam	197	83	(115)	183	99	(84)
Reid CT	-	-	-	-	-	-
HMPL 1	874	993	119	873	993	120
HMPL 2	834	985	151	830	958	127
	10,729	11,464	735	10,719	11,433	714
Capacity Factor (nameplate)						
	Stand Alone	**In-MISO**	**Increase**	**Stand Alone**	**In-MISO**	**Increase**
Coleman 1	66%	76%	10%	67%	80%	13%
Coleman 2	65%	75%	9%	65%	77%	11%
Coleman 3	64%	73%	8%	65%	71%	6%
Wilson	84%	84%	0%	84%	84%	1%
Green 1	80%	86%	6%	80%	84%	4%
Green 2	82%	87%	5%	83%	85%	3%
Reid Steam	35%	15%	-20%	32%	17%	-15%
Reid CT	0%	0%	0%	0%	0%	0%
HMPL 1	65%	74%	9%	65%	74%	9%
HMPL 2	60%	71%	11%	60%	69%	9%
Production Costs (M$)						
	Stand Alone	**In-MISO**	**Increase**	**Stand Alone**	**In-MISO**	**Increase**
Coleman 1	32.0	36.6	4.6	33.5	40.0	6.4
Coleman 2	31.4	35.7	4.2	32.5	37.9	5.4
Coleman 3	32.6	36.6	4.0	34.7	37.7	3.0
Wilson	77.8	78.2	0.4	81.2	81.8	0.6
Green 1	49.8	53.4	3.6	52.1	54.8	2.7
Green 2	49.2	51.9	2.7	51.8	53.4	1.6
Reid Steam	9.6	4.0	(5.6)	9.6	5.2	(4.5)
Reid CT	0.0	0.0	0.0	0.0	0.0	0.0
HMPL 1	32.9	37.1	4.3	34.8	39.4	4.6
HMPL 2	31.8	37.4	5.6	33.6	38.5	4.9
	347.2	371.0	23.9	363.9	388.6	24.7

COMMONWEALTH OF KENTUCKY
BEFORE THE
PUBLIC SERVICE COMMISSION OF KENTUCKY

Case No. 2010-00___

DIRECT TESTIMONY OF
CLAIR J. MOELLER

ON BEHALF OF
APPLICANTS

FEBRUARY 2010

DIRECT TESTIMONY OF
CLAIR J. MOELLER

Q. PLEASE STATE YOUR NAME, CURRENT POSITION AND YOUR BUSINESS ADDRESS.

A. My name is Clair J. Moeller. I am the Vice President of Transmission Asset Management for the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO"). My business address is 1125 Energy Park Drive, St. Paul, Minnesota 55108.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I hold a Bachelor of Science in Electrical Engineering from Iowa State University in Ames, Iowa. I have occupied my current position with the Midwest ISO since January 2004. I have over twenty-five years of industry experience in the operation of power systems, and held engineering and management positions in system operations with Xcel Energy Corporation prior to my employment with the Midwest ISO. I have been involved in the creation of the industry-leading, innovative framework developed for the participation of independent transmission companies in regional transmission organizations ("RTOs").

Q. PLEASE DESCRIBE YOUR JOB RESPONSIBILITIES WITH THE MIDWEST ISO AS THEY RELATE TO THIS PROCEEDING.

A. My responsibilities with the Midwest ISO include oversight of the existing operational functions of transmission planning, including internal, cross-border and interregional transmission planning coordination. My responsibilities also include administering traditional transmission services and managing the use of transmission capacity between the Midwest ISO's Energy and Operating Reserve Markets and the surrounding non-market areas.

Q. HAVE YOU SPONSORED ANY OTHER TESTIMONY BEFORE REGULATORY COMMISSIONS?

A. Yes. I have submitted prepared testimony before the Federal Energy Regulatory Commission ("FERC") involving matters specific to the Midwest ISO.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I will generally describe the Midwest ISO and what we do, how we operate and are governed, the nature of the services that the Midwest ISO proposes to provide to Big Rivers under our Tariff, and the benefits I believe will accrue to Big Rivers from its participation as a Transmission Owning member of the Midwest ISO.

Q. PLEASE DESCRIBE THE MIDWEST ISO AND ITS BUSINESS ACTIVITIES.

A. The Midwest ISO is an independent, non-profit organization responsible for maintaining reliable transmission of power in 13 U.S. states and the Canadian province of Manitoba. In 2001, the Midwest ISO was approved as the nation's first regional transmission organization ("RTO") by FERC. On April 1, 2005, the Midwest ISO began operating its Real-Time and Day-Ahead energy markets and a market for Financial Transmission Rights ("FTR"), and on January 6, 2009, its Ancillary Services Market ("ASM"). The Midwest ISO is headquartered in Carmel, Indiana, with operations control centers in Carmel and St. Paul, Minnesota. Approximately 300 registered Market Participants serve over 40 million people in one of the world's largest energy markets, clearing nearly $41 billion in energy transactions annually.

Q. PLEASE DESCRIBE THE GOVERNANCE STRUCTURE OF THE MIDWEST ISO.

A. The Midwest ISO is governed by an independent eight-member Board of Directors, with seven independent directors elected by the membership, plus the president/chief executive officer of Midwest ISO. No board member may have been a director, officer or employee of a Midwest ISO member, user, or affiliate of a member or user for two years before or after election to the Board. Under the Midwest ISO's Standards of Conduct, all Midwest ISO board members, employees and their immediate family members are required to divest any holdings in member or user companies. There are nine stakeholder segments from Transmission Owners to public consumer advocates that elect a representative Advisory Committee to recommend actions to the RTO. Below the Advisory Committee there are several key technical and policy subcommittees and work groups that meet regularly to address developing issues in all areas, and make recommendations to the Advisory Committee. With few exceptions (e.g., certain meetings of the Transmission Owners Committee, the Reliability Subcommittee discussing critical system infrastructure, etc.), Midwest ISO committee and board meetings are noticed by posting on our web site and are open to the public—although only Midwest ISO members are permitted to vote on motions. Finally, the views of state regulators are represented through an independent stakeholder group, the Organization of MISO States ("OMS"). I have included as my Exhibit CJM-1 a chart illustrating the Midwest ISO's committee structure.

Q. PLEASE DESCRIBE THE SERVICES THAT BIG RIVERS WOULD RECEIVE AS A MEMBER OF THE MIDWEST ISO.

A. The Midwest ISO performs a number of functions that it will provide for Big Rivers. These services originate in Article Three of the Transmission Owners Agreement creating the Midwest ISO. These functions include: monitoring energy transfers on the Big Rivers high voltage transmission system; scheduling transmission service and performing tariff administration for Big Rivers; managing transmission congestion in and around the Big Rivers system through security-constrained economic dispatch; operating the Day-Ahead and Real-Time energy markets; balancing load and generation in real time; and performing regional transmission planning. In order to provide these services the Midwest ISO is registered with NERC as a Reliability Coordinator ("RC"), Planning Authority ("PA"), Transmission Service Provider ("TSP"), Balancing Authority ("BA"), and Interchange Authority ("IA"). On January 6, 2009, the Midwest ISO began to administer an operating reserves market, often referred to as our Ancillary Services Market ("ASM") and to perform Balancing Authority functions. When it began operating as a NERC-certified Balancing Authority, the obligation to carry reserves shifted from the multiple BAs in the Midwest ISO footprint to the new Midwest ISO Balancing Authority. The Midwest ISO now performs the majority of BA responsibilities including Automatic Generation Control ("AGC"), Control Performance Standard ("CPS"), and Disturbance Control Standard ("DCS"), while Local Balancing Authorities ("LBAs") perform an important subset of these requirements such as tie line metering, load shedding, and the development and implementation of restoration plans. During October 2009 the Midwest ISO underwent a comprehensive NERC audit of these functions, with no violations or recommendations for corrective measures. Additional detail regarding the Midwest ISO Real Time operations and reliability tools is provided by Midwest ISO Witness Zwergel.

Q. PLEASE DESCRIBE THE AGREEMENTS THAT MUST BE EXECUTED BY BIG RIVERS TO EFFECT ITS INTEGRATION INTO MIDWEST ISO.

A. Each prospective Transmission Owner must apply for membership. Big Rivers has completed this step by submitting the "Midwest ISO Membership Application", which was accepted by the Board of Directors on December 14, 2009. Because Big Rivers will not be integrating its facilities immediately, but has requested a phased integration to be completed by September 1, 2010, the Midwest ISO and Big Rivers entered into a "Memorandum of Understanding" providing that if Big Rivers should decline to complete the integration process, it must reimburse the Midwest ISO its legal and staff costs incurred on behalf of the cancelled integration. Following the Board's acceptance of its application, Big Rivers executed the "Agreement of Transmission Facilities Owners to Organize the Midwest Independent Transmission System Operator, Inc., a Delaware Non-Stock Corporation"

("TO Agreement"). The TO Agreement is the original source document creating the Midwest ISO, its Board of Directors and its committees. The TO Agreement sets forth the relationship of the RTO to the owners and other stakeholders, and preserves certain rights exclusively to the owners regarding the ability to set and alter their individual rates for the use of their facilities.

Each new member must also sign the "Appendix I Supplemental Agreement by and between the Midwest ISO, International Transmission Company and each of the Midwest ISO Transmission Owners" to acknowledge the status of ITC as an independent, stand alone transmission company operating under Appendix I of the TO Agreement. (There are no financial obligations or additional duties associated with this particular document for Big Rivers.) Each new Transmission Owner also executes the "Funds Trust Agreement", pursuant to which money paid by users of the transmission system is wired immediately to a trustee, without ever being under the control of the Midwest ISO, for distribution to the Transmission Owners. This insulates Transmission Owners from the remote risk of financial insolvency of the Midwest ISO that might otherwise tie up funds in litigation before they could be distributed to the TO. Under the TO Agreement, each new transmission owning member must transfer to the functional control of the Midwest ISO all transmission facilities rated at or above 100kV. They may transfer lower voltage transmission facilities as well, but if they choose not to do so they must execute the "Agency Agreement" found in Appendix G of the TO Agreement. This document allows the Midwest ISO to grant seamless transmission service under the Midwest ISO Tariff to customers served at those lower voltages, and permits the transmission owner to include those lower voltage facilities in its Attachment O rate calculation, assuring that it recovers its revenue requirement associated with those facilities.

Because Big Rivers is a NERC registered Balancing Authority, it will need to sign the "Balancing Authority Agreement" to delegate certain BA tasks and responsibilities to the Midwest ISO. This document was developed to permit the Midwest ISO to initiate the Ancillary Service Market and take on the associated Balancing Authority function. Even though Big Rivers is not FERC jurisdictional with regard to its transmission rates, it may wish to sign the "Settlement Agreement Between Transmission Owners and the Midwest ISO on Filing Rights" delineating the FERC 205 filing rights held by the Midwest ISO and those of the Transmission Owners with regard to rates. That document is maintained by counsel for the Transmission Owners, not by Midwest ISO, and we have provided Big Rivers the contact information for that purpose. In addition to these documents that require signature, there are several steps that Midwest ISO and Big Rivers will be working on jointly to effect the integration. These include preparing a formal listing of transferred facilities, reviewing existing transmission service contracts for grandfathered ("GFA") treatment, calculation of allocated Financial Transmission Rights, training for Big Rivers personnel, establishing communication links, and registration of assets in our models. The list is not exhaustive.

Q. PLEASE ADDRESS THE SIGNIFICANCE OF THE SEPTEMBER 1ST INTEGRATION DATE.

A. In order to correctly model the Big Rivers loads and resources in the Midwest ISO commercial model for September 1, 2010 integration, Big Rivers must have assurance that it can join the Midwest ISO no later than August 1, 2010. If that date cannot be met, there are two consequences. The first is that integration will need to be postponed until the next quarterly model update, delaying integration until December 1, 2010, at the earliest. Such a delay would have the corresponding effect of delaying Big Rivers sharing in the benefits of Midwest ISO participation, as discussed below and elsewhere. The second consequence is that the Midwest ISO will need to file a request with FERC to modify Attachment RR, which allows Big Rivers to obtain reserves. Under the terms of that tariff provision a party must complete its integration within nine months of beginning Attachment RR service. Although I believe FERC would be receptive to extending the deadline to accommodate a good faith integration effort, one cannot be certain of such outcomes, particularly if other parties intervene and oppose the extension. Further, the Midwest ISO would be asking FERC to waive its 60 day notice requirement for tariff changes, since we would likely be making such a filing after the August 1st modeling deadline had passed with no approval from this Commission.

Q. ARE THERE BENEFITS FROM BIG RIVERS' MEMBERSHIP IN THE MIDWEST ISO?

A. There are several significant benefits. First, Big Rivers will experience improved local and regional reliability. Second, Big Rivers will gain full access to the benefits of the Midwest ISO's efficient, market-based congestion management mechanisms. Third, Big Rivers' membership will enable it to reduce energy costs by gaining access to a larger, and more diverse, generation mix with no additional transmission charges. Finally, Big Rivers will reduce its administrative costs and uplifts by exploiting the economies of scale in a centralized organization. For clarity, I note that many of the benefits I will describe, in particular the ancillary services operating reserves market, did not exist at the time LG&E withdrew from the Midwest ISO in 2006, and even the energy market then in effect was too new to have accumulated sufficient data for anyone to understand and predict with confidence the level of benefits to Midwest ISO membership.

Many of these benefits are also discussed by Midwest ISO Witnesses Doying and Zwergel.

Q. PLEASE DESCRIBE THE RELIABILITY BENEFITS.

A. Before I discuss the many reliability benefits of Midwest ISO membership, I believe it is necessary to review the current, less efficient transmission loading relief process ("TLR"), that Big Rivers currently is required to operate under. The TLR process is a suboptimal solution to address congestion problems. A more efficient congestion management is the LMP-based market solution to congestion management. Unlike LMP-based congestion management, the TLR process does not investigate the *least-cost alternative* for congestion management, but simply curtails all transactions in the offending direction until the congestion problem is solved. Under a TLR regime, there is no process or capability to consider the cause of the problem and attempt to correct it. Furthermore, since there is no economic information associated with the hourly transmission schedules used to effect curtailment, it is not possible to determine the most economic option as is the case with the Midwest ISO's LMP-based process. TLRs do not actually relieve congestion for 30 to 60 minutes, creating this inefficient and potentially costly delay. LMP-based congestion management optimizes in the least-cost or most efficient manner on a five-minute interval. This increase in efficiency benefits market participants like Big Rivers. The most recent analysis performed by the Midwest ISO for its Value Proposition calculates these improved reliability benefits of between $263 million and $394 million annually as compared to using TLR. As I explain later in my testimony, and illustrate in Exhibit CJM-2, Table 1, Big Rivers would realize approximately 1.7% of those benefits, or $4.4 to $6.6 million.

In addition to the above reliability benefits, Big Rivers' membership will experience improved reliability in two other important ways. First, the inclusion of Big Rivers' generation in the expanded footprint in the Day-Ahead Energy and Operating Reserve Market will enable the application of Security Constrained Unit Commitment ("SCUC") within the next-day Reliability Assessment Commitment ("RAC") process to access generators that today Big Rivers cannot access for its own dispatch needs (i.e., automatically in real time, without the need to schedule a purchase and arrange for transmission service). This will ensure that there is a set of generators on line at the appropriate times to be able to manage the power system within safe parameters. Second, because the Midwest ISO can "see" developments in the entire Midwest region, including Kentucky beyond the Big Rivers system, it allows preemptive rather than reactive action to protect reliability. These benefits are reciprocal, in that adding the Big Rivers system to the Midwest ISO pool improves the reliability of the entire footprint, including Big Rivers, for the reasons described. The Midwest ISO will receive more information, timely information, and comprehensive information. This expanded and more detailed data flow will increase the Midwest ISO's range of vision while allowing timely interdiction of circumstances that, if left unchecked, could threaten system stability. In contrast, if Big Rivers were to choose not to participate, I believe there would be no degradation, but no improvement in reliability for either Midwest ISO or Big Rivers. In such a case, the only tool available to resolve congestion in the Big Rivers system would continue to be TLR, which is a suboptimal solution.

Q. PLEASE DESCRIBE HOW THE MIDWEST ISO CONGESTION MANAGEMENT MECHANISM WOULD ADDRESS INEFFICIENCIES.

A. A seam between two transmission systems, whether market or non-market, causes a number of dislocations and inefficiencies. In the case of a seam between an organized market and a non-market area there are additional complexities because the non-market area is not transparent, making it impossible to accurately predict parallel flows caused by the non-market activity on the transmission facilities used by the centrally dispatched market. This inability to predict flow reduces efficiency on both sides of the seam. On the non-market side, this often results in TLR, with all of its negative consequences. On the market side of the seam, the inefficiency is manifested in two ways. First, unfunded congestion costs increase and are uplifted to the entire Market Participant base. It is not possible to allocate the congestion cost across the seam to the non-market area. Second, the market incurs additional Revenue Sufficiency Guarantee ("RSG") costs as generators are ordered on for the sole purpose of managing congestion. These costs are similarly uplifted to the entire market footprint. This suboptimal outcome is avoided, however, if the seam is managed using the SCUC and Security Constrained Economic Dispatch ("SCED") protocols for market participants.

Today, both Big Rivers and the Midwest ISO benefit from the seams agreement among the Midwest ISO, PJM and TVA to manage the market to non-market seam that exists between Big Rivers and the Midwest ISO in northern Kentucky. Big Rivers is still subject to TLRs, however, when it must reduce flows on certain designated flowgates, called Reciprocally Coordinated Flowgates. If Big Rivers is integrated into the market, it will move into the market area and gain the advantage of managing congestion using the SCUC and SCED protocols. The cost of congestion management will move from Big Rivers' on-system redispatch or curtailed transactions responding to a TLR, to being included in the LMPs at the location experiencing the congestion. Thus, Big Rivers will see congestion costs reflected in the LMPs in its area, but the congestion cost experienced after

Big Rivers becomes a Midwest ISO member will be less than its historic cost of accommodating a TLR obligation due to the same efficiency logic described. In short, the cost of congestion management on the Big Rivers system will be reduced.

Q. PLEASE DESCRIBE THE MIDWEST ISO REGIONAL PLANNING PROCESS.

A. RTO planning functions include the provision of long-term Transmission Service, Interconnection Service, and regional planning. These services are provided collaboratively with member Transmission Owners, consistent with the Transmission Owner's Agreement. The Midwest ISO is registered with NERC as a Planning Coordinator and, as such, fully evaluates and plans for the reliability of the transmission system in accordance with the NERC planning standards. The Midwest ISO develops an annual regional expansion plan based on expected use patterns and analysis of the performance of the Transmission System in meeting both reliability needs and the needs of the competitive bulk power market, under a wide variety of contingency conditions.

This analysis and planning process integrates into the development of the regional plan among other things: (i) the transmission needs identified from Facilities Studies carried out in connection with specific transmission service requests; (ii) transmission needs associated with generator interconnection service; (iii) the transmission needs identified by the Transmission Owners in connection with their planning analyses in accordance with local planning processes, to provide reliable power supply to their connected load customers and to expand trading opportunities, better integrate the grid and alleviate congestion; (iv) the transmission planning obligations of a Transmission Owner, imposed by federal or state laws or regulatory authorities; (v) plans and analyses developed by the Transmission Provider to provide for a reliable Transmission System and to expand trading opportunities, better integrate the grid and alleviate congestion; (vi) the identification, evaluation, and analysis of expansions to enable the Transmission System to fully support the simultaneous feasibility of all Stage 1A Auction Revenue Rights ("ARRs"); (vii) the inputs provided by the Planning Advisory Committee; and (viii) the inputs, if any, provided by the state regulatory authorities having jurisdiction over any of the Transmission Owners and by the Organization of Midwest ISO States.

The development of the regional plan is undertaken in an open and transparent planning process as prescribed by FERC Order 890, which provides multiple opportunities for all stakeholders to review and provide input into the plan. These FERC planning principles also require close inter-regional planning coordination with neighboring systems and are accomplished via the joint operating agreements included as rate schedules to the tariff. Periodic inter-regional plans are developed that ensure that the systems of Midwest ISO members are not negatively impacted by the planning decisions of nearby entities.

Planning for the reliable interconnection of new generation, of both affiliated and independent power producers is provided for by the Midwest ISO as the Transmission Provider. System Impact and Facilities Studies are conducted collaboratively with the impacted Transmission Owners and adhere to the local planning criteria of those Owners, as well as to national and regional planning criteria under the NERC umbrella.

Q. HOW ARE THE COSTS OF TRANSMISSION EXPANSION PAID FOR?

A. In general the Midwest ISO transmission rates are based on a "license plate" tariff construct in which Network Customer rates reflect the revenue requirements of the local pricing zone. Under this arrangement transmission constructed locally for ongoing reliability needs are generally recovered from local customers. Beginning in 2006, the Midwest ISO instituted regional cost sharing for certain transmission upgrades meeting specified criteria. Under the present tariff, cost sharing for transmission is somewhat different depending on whether the transmission is needed for ongoing reliability, to reduce congestion and improve market efficiency, or to interconnect new generation. For larger ongoing reliability and market efficiency upgrades of 345 kV voltage and higher and of at least $5 million in direct costs, 80% of the cost is allocated (using load flow studies) to loads that benefit from the project, with 20% of the cost of the upgrades shared equally by all loads. Smaller projects of this type are shared between locally close zones with the majority of the costs remaining in the local zone. Transmission upgrades constructed to reliably interconnect new generation, except for the highest voltage transmission, is paid for entirely by the generator interconnection customer. For high voltage upgrades at 345 kV and above, the interconnection customer pays for 90% of the cost with the remaining costs shared equally by all loads. The mechanism for collecting these allocated expansion costs is Schedule 26, which currently does not apply to grandfathered agreement ("GFA") load. These Midwest ISO transmission expansion cost allocation methods I have described are currently being discussed with stakeholders, including state regulators, with an eye to revising them in a FERC filing in July 2010.

Q. WHAT IS THE MIDWEST ISO "VALUE PROPOSITION"?

A. That term refers to a detailed calculation, updated frequently, to determine whether the Midwest ISO functions are worth the costs of running the RTO. Because RTOs are voluntary organizations, if a transmission owner or its regulator perceives that the costs of participation do not provide a commensurate value to the ultimate end users of electricity, they will terminate their membership. The Midwest ISO publishes its most current calculations of the Value Proposition on its public website, with supporting work papers illustrating and explaining the calculations. As you can see from my Exhibit CJM-2, Table 1, the Value Proposition breaks the Midwest ISO business model into certain recognized categories of benefits to the footprint as a whole and calculates a range of dollar values for each defined category. The benefits studied are: reliability, energy dispatch, unloaded capacity, regulation, spinning reserves, diversity of resources in the footprint, generator availability, and two categories of demand response (dynamic pricing and interruptibles). The most recent calculation indicates a footprint-wide total <u>net</u> benefit ranging from $1.2 billion to $1.55 billion. In other words, if the Midwest ISO did not exist, customers in our region would pay, in the aggregate, an additional $1.2 to $1.55 billion more every year for electricity. The Midwest ISO's current Value Proposition can be found by clicking the arrow in the upper right-hand corner of the Midwest ISO's Internet home page, http://www.midwestiso.org/home.

Q. PLEASE EXPLAIN THE DERIVATION OF THE VALUE PROPOSITION.

A. From the outset, I recognize that many of the benefits I will touch upon are easy to describe but difficult to measure and fully quantify with precision. For these reasons the Value Proposition takes the approach of providing a range of benefits for each discrete category, from low to high, within which we believe the actual benefits for our participants exist. This concept and the results I provide below have been thoroughly vetted and scrutinized by our diverse stakeholder community, and the numbers provided in Exhibit CJM-2, Table 1, reflect the second iteration of the analysis. These figures, explanatory presentations, and the supporting calculations are all posted on the Midwest ISO web site. We submit that as such it does represent credible evidence regarding the relative value and benefits of the Midwest ISO, a primary issue under consideration by this Commission in this important review process.

Q. WHAT ADDITIONAL BENEFITS WOULD BE AVAILABLE TO BIG RIVERS AS A MEMBER OF THE MIDWEST ISO?

A. Big Rivers would accrue significant direct and indirect benefits from participation as a member of the Midwest ISO – benefits that are not necessarily entirely captured by traditional production cost analyses. These additional benefits can be grouped under the following three general categories: (1) improved reliability; (2) improved efficiency (in areas in addition to the efficiencies of a regional dispatch of energy); and (3) improved opportunities for development of generation and transmission infrastructure. I am aware that some of the benefits under general category 2 are or may be addressed to a degree by the CRA-Big Rivers production cost study, but there are others that may not be fully covered that I will touch upon. Due to the complexities inherent with the CRA-Big Rivers Study and the different, broader scope of the Midwest ISO Value Proposition that I am presenting in my testimony, a direct comparison or analysis cannot and should not be made. I submit this Value Proposition as evidence of benefits accruing to all participants in the Midwest ISO, and thus by extension to Big Rivers. I will discuss each of the above general three categories in turn.

Q. WOULD YOU REVIEW AND DESCRIBE THE DISCRETE AND DIRECT BENEFITS FOR BIG RIVERS UNDER THESE GENERAL THREE CATEGORIES OF VALUE AND BENEFIT AS SET FORTH IN THE MIDWEST ISO'S VALUE PROPOSITION?

A. While the Midwest ISO has not performed any specific studies attempting to quantify the benefits that can be attributed to Big Rivers should it join the Midwest ISO, the Midwest ISO believes that the benefits it creates are real, and Big Rivers' participation will allow it to share in the broader benefits discussed and described in the market-wide Midwest ISO Value Proposition analysis that I will briefly discuss below. While this Midwest ISO-wide value proposition was not designed to be company-by-company specific (nor can it be), roughly speaking, Big Rivers represents approximately 1.7%[1] of the load and generation within the Midwest ISO foot print, and therefore I utilize 1.7% of the overall ranges of numbers presented below as a reasonable and appropriate level of magnitude of the potential benefit for Big Rivers' participation in the Midwest ISO.

Q. WHAT IMPROVED RELIABILITY CAN AND WOULD BIG RIVERS RECEIVE BY JOINING THE MIDWEST ISO, AND WHAT DO YOU ESTIMATE THE VALUE OF THOSE BENEFITS TO BE?

A. Reliability of electrical service is a function of sufficient supply and consistent transmission capability. Reliability is compromised if there is too little energy created, or if too little capacity exists to carry it to the customer. The Midwest ISO's broad regional view and state-of-the-art reliability tool set enable Improved Reliability for the region as measured by transmission system availability. Transmission system availability is based on an analysis of NERC's outage information. The benefits are several, and can be further broken down into the subcategories of: (a) improved reliability as compared to stand-alone operations, (b) seams and tariff management functions; and (c) regulatory compliance. In all three of these subcategories, the obligations and responsibilities for these complicated and resource-

---

1 This amount (rounded from 1.67%) was calculated using Big Rivers' projected 2010 peak load of 1,657 MW versus the projected Midwest ISO 2010 peak load of 99,208 MW.

demanding functions is either taken on completely by the Midwest ISO, or shared with the new entity. In the Midwest ISO compilation process, we have only been able to approximate total benefits for these above noted three reliability-related subcategories.

Midwest ISO Annual Benefit by Value Category: Improved Reliability[2]

Market-wide Improved Reliability Benefit	**Big Rivers' Potential**
$263 to $394 million	$4.47 to $6.70 million

Q. WHAT IMPROVED MARKET-COMMITMENT AND DISPATCH EFFICIENCIES WOULD BIG RIVERS RECEIVE FROM JOINING THE MIDWEST ISO, AND WHAT DO YOU ESTIMATE THE VALUE OF THOSE BENEFITS TO BE?

A. The benefits of dispatch and market efficiencies are also multiple, and can likewise be further broken down into the subcategories of: (d) a more efficient dispatch of energy as compared to stand-alone operations, (e) a more efficient dispatch of unloaded capacity; (f) better dispatch and utilization of assets to provide for necessary regulation reserves; and (g) a more efficient dispatch of assets to provide for spinning reserves. I will provide a brief description of each subcategory.

---

2 Figures reflect annual benefits reflected in 2009 U.S. dollars, including both current and achieved benefits and projected future benefits.

(d) Energy dispatch occurs when the Midwest ISO schedules, monitors and controls the distribution of energy. The Midwest ISO's Real-Time and Day-Ahead energy markets use security constrained unit commitment and centralized economic dispatch. This optimizes the use of all resources within the region based on bids and offers by market participants. This results in optimized transmission utilization, reduced transaction costs, high market transparency, elimination of pancaked transmission rates, and centralized unit commitment and dispatch.

(e) Unloaded Capacity is the amount of capacity remaining on the committed units above their dispatch point. With the start of the Ancillary Services Market and the functional consolidation of the region's Balancing Authorities, responsibility to respond to operating issues was consolidated in the Midwest ISO. This eliminates the need for multiple Balancing Authorities to hold Unloaded Capacity. The reduction of Unloaded Capacity benefits the region by allowing the available capacity to be used for energy dispatch.

(f) System operators dispatch energy to continuously regulate the balance of electrical supply and demand. With the start of the Midwest ISO Regulation Market and with the Midwest ISO's assumption of the role as the region's central Balancing Authority, the region has moved from a number of non-coordinated Regulation targets to a centralized common footprint Regulation target. This has resulted in the amount of Regulation reserves required within the Midwest ISO's footprint to drop significantly. This reduction in Regulation reserves frees up generation units that can, in turn, sell into the market to others in need of energy.

(g) Spinning Reserves are used to provide energy to meet demand on the system in the event of a sudden and unexpected loss of a generation or transmission resource. Starting with the formation of the Contingency Reserve Sharing Group ("CRSG") and continuing with the implementation of the Spinning Reserves Market, the total spinning reserve requirement has been reduced by over 25% from Pre-CRSG standards. This reduction in Spinning Reserves frees up generation units to serve the broader energy demands within other parts of the region.

In each of these four market-commitment and dispatch subcategories, the obligations and responsibilities for these sometimes complicated and resource-demanding functions are either taken over by the Midwest ISO by virtue of participation by Big Rivers or brought into uniformity and virtual compliance through the FERC approved market standards and controls that have become increasingly complex.

Midwest ISO Annual Benefit by Value Category: Improved Efficiencies[3]

Market-commitment and Dispatch Efficiencies Benefit	**Big Rivers' Potential**
Dispatch of energy: $210 to $264 million	$2.73 to $3.43 million
Unloaded Capacity: $199 to $213 million	$3.38 to $3.62 million
Regulation: $184 to $194 million	$3.13 to $3.30 million
Spinning Reserves: $76 to $81 million	$1.29 to $1.38 million

Q. WHAT ARE THE IMPROVED OPPORTUNITIES FOR UTILIZATION AND DEVELOPMENT OF GENERATION AND TRANSMISSION INFRASTRUCTURE THAT BIG RIVERS WOULD HAVE ACCESS TO BY JOINING THE MIDWEST ISO, AND WHAT DO YOU ESTIMATE THE VALUE OF THOSE BENEFITS TO BE?

A. These benefits are more difficult to quantify, but primarily arise from the broader advantages that a regional area provides load serving entities like Big Rivers. Because of its unique role and access to certain information, the Midwest ISO can independently navigate the many complex and competing financial, economic, and regulatory issues that arise when transmission improvements and expansions become necessary. All members know and depend upon the Midwest ISO's role to focus on the most cost-effective option that becomes necessary to support the interconnected individual and regional systems to maintain a reliable and dependable regional

---

[3] Figures reflect annual benefits reflected in 2009 U.S. dollars, including both current and achieved benefits and projected future benefits.

transmission system. These types of benefits are more challenging to quantify, but they are a reality nonetheless and can have significant impacts.

(h) The first advantage comes in the form of what we call "Footprint Diversity". Footprint Diversity means the benefits that arise because each Load Serving Entity's peak does not coincide with the Midwest ISO's system peak. To account for this diversity of the peaks and ability to shift power as individual peaks occur at different times within the entire system, the regional planning reserve margin established by a Loss of Load Expectations study showed a decrease from a typical 15.4% down to 12.69%. This significantly lower planning reserve margin that is enabled by the Midwest ISO's larger coordinated footprint creates considerable benefits for the region by allowing participating entities to defer investments in new generation. This Footprint Diversity translates into new generation avoided cost which has been quantified and annualized using an estimated revenue requirement based upon this planning reserve margin decrease.

(i) A second advantage is what we call "Generator Availability Improvement." This category attempts to measure the percentage of the year a power plant is fully available. Competitive wholesale power markets provide incentives for generation owners to take actions to achieve a higher generator availability and lower forced outage rates, and thus maximize revenues generated from the energy produced and sold within the market. The Midwest ISO's wholesale power market has quantified this benefit as a Generator Availability Improvement of 3.1%. This improvement will inure to the benefit of each participant and the region generally by allowing the deferral of otherwise necessary investments in new generation. This additional new generation avoided cost has been quantified and then annualized using an estimated revenue requirement based upon the further planning reserve margin decrease.

Midwest ISO Annual Benefit by Value Category: Investment Deferral[4]

Generation Investment Deferral Benefit		**Big Rivers' Potential**
Footprint Diversity:	$217 to $272 million	$3.69 to $4.62 million
Gen. Avail. Imp.:	$249 to $311 million	$4.23 to $5.29 million

Q. WHAT ARE THE IMPROVED OPPORTUNITIES FOR DEMAND RESPONSE PARTICIPATION IN THE WHOLESALE MARKETS OPERATED BY THE MIDWEST ISO, AND WHAT DOES THE MIDWEST ISO VALUE PROPOSITION ESTIMATE THOSE BENEFITS TO BE?

4 Figures reflect annual benefits in 2009 U.S. dollars, including both current and achieved benefits and projected future benefits.

A. The specific details and benefits that are available from an active demand response component in the Midwest ISO markets are more fully described in Midwest ISO Witness Doying's testimony. Consistent with the above discussions regarding the Midwest ISO Value Proposition, I am summarizing and presenting the broader analysis and quantification identified by our analysis codified in the Midwest ISO Value Proposition. These benefits are derived, to-date, in two distinct areas: (j) dynamic wholesale pricing; and (k) direct load control and interruptibles.

(j) Dynamic Pricing is a form of demand response that provides wholesale customers a rate signal that varies throughout the day to reflect the higher cost of electricity during peak times. Midwest ISO provides a market framework that enables Dynamic Pricing programs to realize its full value through the reduction of system peak demand. This demand reduction, in turn, results in additional benefits to Big Rivers and the entire region by allowing further generation investment deferrals.

(k) Wholesale market Direct Load Control and Interruptibles are two forms of demand response. Direct Load Control provides Load Serving Entities the ability to curtail specific end-uses of customers while Interruptibles provide LSEs the ability to curtail a preset amount of load. Midwest ISO provides a market framework that enables Direct Load Control and Interruptibles programs to realize its full value through the reduction of system peak demand. This additional demand reduction adds benefits to Big Rivers and the entire region by allowing further generation investment deferrals. The Midwest ISO has quantified these demand response opportunities as follows:

<u>Midwest ISO Annual Benefit by Value Category: Demand Response</u>[5]

Market-wide Demand Response Potential Benefit		**Big Rivers' Potential**
Dynamic Pricing:	$4 to $7 million	$0.069 to $0.119 million
Direct Load/Control Interruptibles:	$58 to $72 million	$0.98 to $1.22 million

Q. WHAT IS THE TOTAL VALUE OF THE ELEVEN CATEGORIES AND SUBCATEGORIES OF MIDWEST ISO VALUE PROPOSITION BENEFITS THAT YOU HAVE DESCRIBED?

A. Exhibit CJM-2, Table 1, shows the following total value of the benefits described above:

<u>Midwest ISO Annual Benefit by Total Value Benefits</u>[6]

Net Annual Market-wide Benefit[7]	**Big Rivers' Potential**
$1,210 to $1,558 million	$20.6 to $26 million

---

5 Figures reflect annual benefits in 2009 U.S. dollars, including both current and achieved benefits and projected future benefits.

6 Figures reflect annual benefits in 2009 U.S. dollars, including both current and achieved benefits and projected future benefits.

7 The Net Benefits do reflect the Midwest ISO operational and other cost components, which total approximately $250 million.

Q. ARE THERE ANY ADDITIONAL BENEFITS IDENTIFIED IN THE MIDWEST ISO VALUE PROPOSITION THAT YOU WOULD LIKE TO DISCUSS?

A. Yes. There are four general categories of qualitative benefits that are worth noting. They are: (1) Price Transparency; (2) Planning Coordination; (3) Regulatory Compliance; and (4) Wholesale Platform for Integrating Renewables. I provide a brief description of each of these important qualitative benefits below.

(1) Improved Price Transparency enables market forces by signaling them to supply energy when it is scarce, invest in transmission to free constraints, and invest in generation to meet long-term and short-term needs. The Midwest ISO's market provides this information at a level of granularity and locational specificity that no traditional decentralized bilateral energy market can match.

(2) In a traditional transmission planning process, a transmission owner ("TO") focuses on relieving transmission constraints and reliability issues in the transmission system they own. In the Midwest ISO's planning process, this "bottoms-up" approach is coordinated between all TOs in the footprint. This planning process is combined with a "top-down" approach that looks at the regional footprint as well as surrounding regions to determine which

transmission investments will allow for the lowest reliably delivered cost of energy for the footprint.

(3) The Midwest ISO adds value by performing several compliance activities on behalf of its members including: (a) holding monthly conference calls with members to jointly develop higher quality input into the standards process; (b) engaging in several NERC standard drafting teams; (c) performing tasks previously performed by each individual Balancing Authority under the Balancing Authority agreement; (d) providing planning coordination services for the resource adequacy process; and (e) providing training services that help our members meet compliance obligations and assist operators in maintaining their certification.

(4) The Midwest ISO adds the following benefits through integration of renewable resources: (a) providing one-stop shopping for interconnection to the system; (b) enabling access to a spot market for energy; and (c) enabling a greater amount of renewable resources to operate in the region than would otherwise be possible.

Q. ARE THERE OTHER BENEFITS BIG RIVERS MIGHT EXPERIENCE FROM MIDWEST ISO MEMBERSHIP?

A. Yes. The Midwest ISO's systems are scalable and can provide service to new members at a modest incremental cost while reducing each member's Schedule 10 costs because the administrative cost denominator will be larger for essentially the same revenue requirement. The technical infrastructure required to accomplish the deployment of these services can further utilize the economies of scale already available within the information technology systems. As a potential member of the Midwest ISO, Big Rivers would participate in these general benefits on the same basis as existing members, and with no distinction based on corporate utility structure; i.e., in the RTO, transmission owners who are public power entities, cooperatives, and investor owned utilities enjoy the same rights and obligations. The lone exception to this general observation is that members who have tax exempt bonds have shorter notice periods to withdraw from the Midwest ISO, in order to protect that tax exempt status in the event of an adverse ruling from the IRS. No member has had occasion to withdraw on that basis.

Q. **PLEASE DESCRIBE THE RTO WITHDRAWAL PROCESS.**

A. FERC has ruled twice that if a Midwest ISO Transmission Owner satisfies the requirements of the Transmission Owners Agreement, it has the contractual right to withdraw from the Midwest ISO *for any reason* because RTOs are voluntary organizations. Should a member, or for that matter a state commission exercising its regulatory oversight of a transmission owning member, decide that the costs of participation are not justified by the benefits received, the Transmission Owner could (after the initial membership commitment of five years) notify the Midwest ISO of its intent to withdraw, and proceed to do so. The Transmission Owners Agreement, in Article Five, sets out the process for members to withdraw from the Midwest ISO. The requirements that must be met are: (1) written notice, effective at the end of the calendar year *after* notice is received (Article Five, Section I); (2) availability of continued transmission service for existing customers (Article V, Section II.A); (3) payment of all financial obligations (Article Five, Section II.B); (4) obligations to construct planned facilities (Article Five, Section II.C); and (5) receipt of any applicable federal and state regulatory approvals (Article Five, Section III).

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

VERIFICATION

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

Clair J. Moeller

STATE OF INDIANA)

COUNTY OF HAMILTON)

SUBSCRIBED AND SWORN TO before me by Clair J. Moeller on this 28th day of January, 2010.

Dorothy M. Shute
Notary Public

My Commission Expires:
My County of Residence:

DOROTHY M. SHUTE
Notary Public, State of Indiana
My County of Residence: Hendricks
My Commission Expires May 8, 2017

Midwest ISO Committee Organization

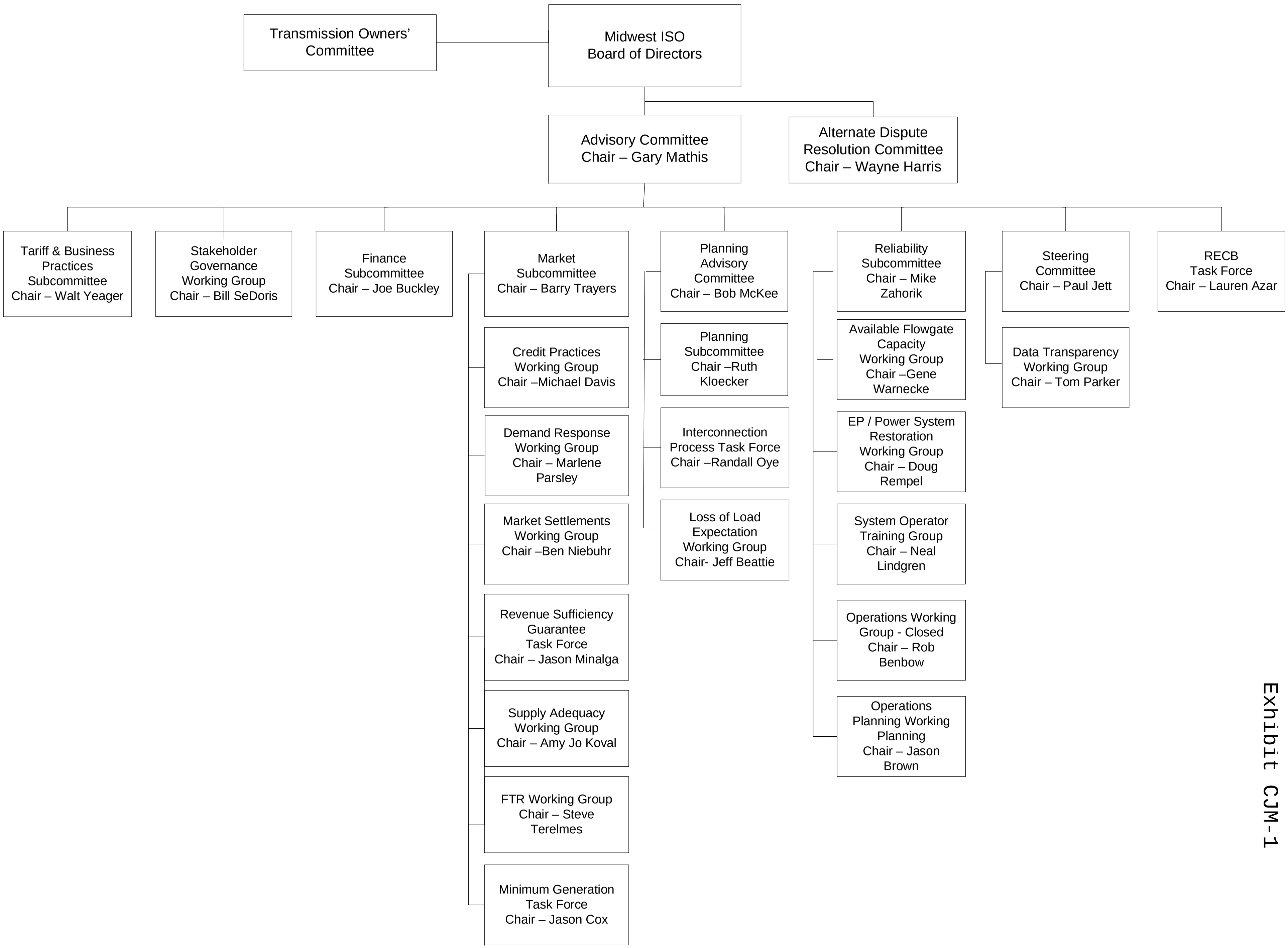


Exhibit CJM-1

Table 1

Midwest ISO
New Member Benefits Estimate for
Big Rivers Electric

Pro-rata Share		
Big Rivers Electric's Projected 2010 Peak Load (MW)[1]	1,657	[a]
Midwest ISO Projected 2010 Peak Load (MW)[2]	99,208	[b]
Pro-rata Share	1.7%	[a]/[b]

[1]Highest peak load in past 12 months (January 16th, 2009) - provided by Big Rivers

[2]Non-Coincident Peak 10-Year LBA Forecast for 2010

Member Benefit Using 2009 Value Proposition ($ in Mils.)

	Midwest ISO Footprint		Big Rivers Electric	
	Low	High	Low	High
Improved Reliability	$ 263.0	$ 394.0	$ 4.4	$ 6.6
Dispatch of Energy	$ 210.0	$ 264.0	$ 3.5	$ 4.4
Unloaded Capacity	$ 199.0	$ 213.0	$ 3.3	$ 3.6
Regulation	$ 184.0	$ 194.0	$ 3.1	$ 3.2
Spinning Reserves	$ 76.0	$ 81.0	$ 1.3	$ 1.4
GROSS BENEFITS	$ 932.0	$ 1,146.0	$ 15.6	$ 19.1
Midwest ISO Cost Structure	$ (250.0)	$ (250.0)	$ (4.2)	$ (4.2)
NET BENEFITS	$ 682.0	$ 896.0	$ 11.4	$ 15.0
Benefits Driven by Load/Supply Balance				
Footprint Diversity	$ 217.0	$ 272.0	$ 3.6	$ 4.5
Generator Availability Improvement	$ 249.0	$ 311.0	$ 4.2	$ 5.2
D. Response - Dynamic Pricing	$ 4.0	$ 7.0	$ 0.1	$ 0.1
D. Response - DLC/Interruptibles	$ 58.0	$ 72.0	$ 1.0	$ 1.2
ADJUSTED NET BENEFITS	$ 1,210.0	$ 1,558.0	$ 20.2	$ 26.0

COMMONWEALTH OF KENTUCKY
BEFORE THE
PUBLIC SERVICE COMMISSION OF KENTUCKY

Case No. 2010-00___

DIRECT TESTIMONY OF DAVID ZWERGEL

ON BEHALF OF APPLICANTS

FEBRUARY 2010

DIRECT TESTIMONY OF
DAVID ZWERGEL

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is David Zwergel. I work at 701 City Center Drive, Carmel, Indiana 46032.

Q. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am Sr. Director of Regional Operations responsible for real time operations of the East and Central Regions within the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO"). The East Region includes portions of northern Ohio, Michigan, northern Indiana and Wisconsin. The Central Region includes portions of southwest Ohio, northern Kentucky, southern Indiana, Illinois, and Missouri, and if Big Rivers is permitted to join the Midwest ISO, the Central Region will include the Big Rivers portions of Kentucky as well. In this position, I oversee the Reliability Coordinator function for the East and Central Regions, including supervising the management of operations engineers and regional dispatchers.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. In 1988, I earned a Bachelor of Science degree in electrical engineering from the University of Pittsburgh. I started in the industry when I graduated from college, so I have more than 21 years experience in the industry. I began my career with Potomac Edison Company, an operating company of Allegheny Power. I worked as a Distribution Planning Engineer, conducting analysis of and planned the distribution network. In November 1990, I worked for Allegheny Power in extra high voltage transmission planning. There, I was involved in planning, analyses and studies of transmission systems for Allegheny Power and regional study groups such as ECAR. In 1996, I continued to work for Allegheny Power in its Transmission Business Unit as an Operations Planning Engineer. I was involved with day to day planning of the operations of the Allegheny Power system, and I advised control area and transmission operators. I also implemented the Reliability Coordination function for Allegheny Power which was known at the time as Security Coordination. I joined the Midwest ISO in June 2000 as Manager of Reliability Coordination. I initially worked on setting up the Reliability Coordinator functions and hiring staff. In 2004, I was promoted to Director of Reliability. I worked on enhancements to the reliability coordination function tools, processes, procedures, and training. In March 2008, I assumed my present duties.

I have been involved extensively in North American Electric Reliability Corporation ("NERC") activities, including serving as Chairman of the Interchange Distribution Calculator Working Group of the NERC Operating

Reliability Subcommittee, which is responsible for implementing NERC's Interchange Distribution Calculator ("IDC") and other tools in support of the NERC Reliability Coordinators. The IDC is a tool for the NERC Transmission Loading Relief ("TLR") Procedure. I also served as Chairman of NERC's Reliability Coordinator Working Group, which includes all Reliability Coordinators in North America. This group serves in an expert advisory role and is responsible for authorizing and reporting certain changes to the models used by the IDC. Finally, I just completed a two year term as Chairman of the NERC Operations Reliability Subcommittee for North America. I continue to be an active member of both the Reliability Coordinator Working Group and Operating Reliability Subcommittee.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I will describe the Midwest ISO reliability coordination function, our tools and processes, and I will explain how reliability on that portion of the regional grid located in the Commonwealth of Kentucky will be enhanced by Big Rivers participating as a member of Midwest ISO, including participation in the Midwest ISO energy market, to the benefit of Kentucky retail customers.

Q. PLEASE DESCRIBE THE MIDWEST ISO RELIABILITY COORDINATION FUNCTION?

A. The Midwest ISO is a NERC registered Reliability Coordinator ("RC"). The RC is responsible for monitoring the Bulk Electric System and directing operators to take actions necessary to preserve the reliability of the region. To perform the RC function an entity must be audited by NERC for compliance with all NERC reliability standards and demonstrate that it has the tools and processes to perform this important function. The tool set used for this purpose must provide the RC with a "wide area view" that not only covers its own region, but gathers information from neighboring RCs as well. The RC must have communication tools and procedures in place to allow it to gather and send critical information to neighboring RCs as well as to the operators in its own Reliability Area. The RC is required to constantly monitor and model the security of the system to assess contingencies. The Midwest ISO regularly submits an updated "Reliability Plan" which NERC approves. Should this Commission authorize Big Rivers to join the Midwest ISO, the plan would be revised to reflect the addition of the Big Rivers transmission system to the Midwest ISO regional responsibilities.

Q. PLEASE DESCRIBE THE TOOLS USED BY THE MIDWEST ISO TO PERFORM THE RELIABILITY COORDINATION FUNCTION?

A. The Midwest ISO has a control center in Carmel, Indiana that includes a dynamic wallboard, state of the art visualization, advanced alarm filtering, and EMS monitoring and tools that result in greatly increased monitoring and alarming capability not only within its own footprint but well into neighboring reliability areas. The Midwest ISO has a backup control facility which NERC auditors described as "the benchmark for the industry". The control center tool set performs the following functions: Visualization, Alarming, Network Topology Processor, State Estimator and Contingency Analysis, Supplemental Monitoring Tools, Congestion Management Tools, and Communications. The Midwest ISO's dynamic wallboard geographically depicts all transmission 230 kV and above (and some lower voltage facilities) for its footprint, and is updated with measured data and status at the SCADA scan rate. The dynamic wallboard provides real and reactive flows in MW and MVAR, voltage profile in kV, generator outputs in MW and MVAR, substation alarm indicators, high and/or low Voltage alerts, open branch indications, and heavy line loading alerts with graphic illustration of line conditions. The dynamic wallboard also includes neighboring reliability area transmission. The Midwest ISO has a tool to monitor its energy markets that displays key information for each control area such as load, interchange, frequency, instantaneous area control error ("ACE"), and operating reserves. This tool provides visual alarms for operating reserves, ACE, and Frequency. The Midwest ISO's State Estimator consistently and robustly solves a 37,115 bus model every 90 seconds utilizing more than 234,311 telemetered data points. The chart below lists the facilities and data points (both Midwest ISO and neighboring) monitored by this tool:

	Market	External	Total	Reliability	External	Total
Circuit Breaker	61189	110171	171360	71150	100210	171360
Bus	11725	25390	37115	13368	23747	37115
Capacitor	1899	4019	5918	2041	3877	5918
Load	9738	20410	30148	10936	19212	30148
Reactors	113	585	698	218	480	698
Stations	7657	15337	22994	8583	14411	22994
Units	1285	4281	5566	1516	4050	5566
Transformers	3615	9416	13031	4114	8917	13031
Lines	10476	23291	33767	11927	21840	33767

Q. HOW DO THESE TOOLS WORK IN PRACTICE?

A. The Midwest ISO's Real-time contingency analysis examines 8,700 contingencies every three minutes including contingencies in neighboring areas. The Topology Processor runs every 4 seconds and does not rely on State Estimator output. It updates Line Outage Distribution Factors and generates equipment outage information for the Equipment Outage Monitor. The reliability tools and visualization capability provide the Midwest ISO with a superb wide area view of its footprint and neighboring areas. The State Estimator already contains data points for the Big Rivers area, including over 32,000 data points in TVA alone, and extending into SPP and Entergy to the south of TVA.

A real-time full scale simulator has direct connection to the AREVA system (AREVA is the vendor of the state estimator, network model) with the capability to replicate real-time conditions and operations including the Midwest ISO detailed network model. The Midwest ISO operations department sets goals, evaluates training needs, including certification and drills, and identifies and implements the expectations and day-to-day training of its personnel. In addition, the Midwest ISO conducts drills with its local balancing authorities and transmission operators to train for various reliability conditions.

Q. DOES THE MIDWEST ISO PERFORM OTHER FUNCTIONS THAT HAVE AN IMPACT ON RELIABILITY OF THE REGION?

A. Yes. The Midwest ISO is also registered with NERC to perform the functions of a Balancing Authority ("BA"), a Planning Coordinator (previously called "Planning Authority") and a Transmission Service Provider. Of these, the most critical to real time operations is the Balancing Authority function which the Midwest ISO assumed beginning January 6, 2009. As with the RC function, the Midwest ISO underwent a thorough NERC audit of its readiness to assume this role. Further, the Midwest ISO received a Balancing Authority certification from NERC. The previously registered Balancing Authorities in the Midwest ISO retain certain BA functions such as metering the tie-lines at the boundary of their Local Balancing Authorities ("LBAs"), but the critical function of maintaining real time generation and load balancing, and insuring adequate reserves, shifted to the Midwest ISO. The specific responsibilities of the LBAs and the Midwest ISO BA are listed in the Joint Registration Organization ("JRO") on file with NERC. For the Midwest ISO BA functions on this list, as well as the Transmission Service Provider functions now performed by Big Rivers, the responsibility for complying with NERC standards will shift to the Midwest ISO after Big Rivers integrates its transmission system. We have operated for more than a year under this model with excellent performance.

Q. WHAT RELIABILITY BENEFITS, IF ANY, WOULD BIG RIVERS GAIN FROM JOINING THE MIDWEST ISO?

A. There are two obvious reliability benefits that stand out. The first is access to a large pool of operating reserves available in the Midwest ISO Energy and Operating Reserves Market ("Midwest ISO Market"). Today, the Midwest ISO has agreed to accommodate Big Rivers' (and Dairyland Power Cooperative's) request to integrate its system on a phased schedule. Beginning January 1, 2010 and until integration is complete, Big Rivers is able to purchase reserves from the Midwest ISO Market under a new rate schedule approved by FERC. (As of the date of my testimony, the Midwest ISO has already supplied Big Rivers with reserves using this mechanism on three occasions.) Under this arrangement, however, there are still certain limitations on the ability of Big Rivers to have these reserves supplied before they must be converted to Emergency Energy purchases to ensure compliance with NERC Standards. Once Big Rivers is fully integrated, the Midwest ISO market structure will simply supply this energy under normal market activities from a much larger pool of resources.

Q. WHAT IS THE SECOND RELIABILITY BENEFIT BIG RIVERS WOULD RECEIVE?

A. The second notable reliability benefit is the resolution of transmission system congestion using Security Constrained Economic Dispatch ("SCED") in real time operations. The ability to resolve congestion using a five minute dispatch signal to raise and lower generation output based on the most economical security constrained solution is far better than having to rely on the TLR process that non-market areas employ. The TLR process is slow and cumbersome from an operator's standpoint, and highly inefficient from a financial standpoint. It takes 30 to 60 minutes to implement the necessary system changes using TLR, and the need to remove a small amount of congestion (e.g., 30 MW) on a given facility often requires the curtailment of much larger transactions (e.g., 150 to 300 MW). The Midwest ISO used TLRs for it primary congestion management tool from 2002 until 2005 when it began operating its LMP-based energy market. Based on my personal experience with both tools, I have no hesitation in stating that Big Rivers' operators will observe significant improvement in their control room operations and system reliability using SCED rather than TLR.

Q. HOW WILL THESE BENEFITS APPLY TO BIG RIVERS?

A. The detailed steps for handling region-wide generation shortages are set forth in Section 40.2.20 of the Tariff (and related business practices) and steps for handling excess generation conditions in real time are found in Section 40.2.21. Further, in the event there is a significant shortage of generation in the Big Rivers Local Balancing Authority, accompanied by transmission constraints which result in limitations in transferring energy into Big Rivers that cannot be managed using normal procedures, the Midwest ISO will utilize emergency procedures both in and around Big Rivers to maintain service to load within Big Rivers. These procedures include reconfiguring the transmission system, manually redispatching generation, operating emergency generation, implementing load management measures, deploying operating reserves, purchasing emergency energy from neighboring BAs, and using emergency transmission limits as needed. The result of these actions, coordinated over a wider regional area, will result in greater reliability to Big Rivers' load. These are emergency conditions, however, that will normally be avoided because the integration of the Big Rivers transmission facilities into the larger Midwest ISO system enables the

Midwest ISO to supply reserves on a continuous basis to Big Rivers. The Midwest ISO coordinates planned transmission and generation maintenance, calculates Available Flowgate Capacity, grants transmission service, and performs security constrained unit commitment in order to proactively maintain the ability to supply energy and reserves to Big Rivers as needed.

Q. WHAT OTHER BENEFITS WILL ACCRUE TO BIG RIVERS WHEN IT JOINS THE MIDWEST ISO?

A. Although access to a large reserve pool and the use of SCED are the most important real time reliability benefits, others will accrue to Big Rivers as well, such as improved regional planning coordination that identifies potential problems not only in, but around, the Big Rivers transmission system. Finally, by integrating into a much larger Balancing Authority, the Big Rivers BA will no longer be responsible for Control Performance Standards and Disturbance Control Standards compliance. Compliance with these NERC Standards becomes the responsibility of the larger Midwest ISO.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

VERIFICATION

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

David Zwergel

David Zwergel

STATE OF INDIANA)

COUNTY OF HAMILTON)

SUBSCRIBED AND SWORN TO before me by David Zwergel on this 28 day of January, 2010.

Christi Finch

Notary Public

My Commission Expires: Aug. 15, 2013
My County of Residence: Hamilton

COMMONWEALTH OF KENTUCKY
BEFORE THE
PUBLIC SERVICE COMMISSION OF KENTUCKY

Case No. 2010-00___

DIRECT TESTIMONY OF
RICHARD DOYING

ON BEHALF OF
APPLICANTS

FEBRUARY 2010

DIRECT TESTIMONY
OF RICHARD DOYING

Q. PLEASE STATE YOUR NAME, CURRENT POSITION AND YOUR BUSINESS ADDRESS.

A. My name is Richard Doying. I am the Vice President of Market Operations for the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO"). My business address is 701 City Center Drive, Carmel, Indiana 46032.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I received my Bachelor of Arts in Geography from the University of California, Los Angeles in 1991 and my Masters of Arts of Public Affairs in Policy Analysis, Energy and Environmental Policy from the University of Minnesota in 1993. Starting in 1993, I was an Associate with ICF Resources Incorporated, becoming a Senior Associate in 1995. In 1997, I was made a Project Manager for ICF Resources Incorporated. In 1997, I became a manager in the Market Assessment division of PG&E National Energy Group, where I was made Director of the same division in 1999. In 2001, I was named the Director of the Strategy and New Initiatives division of PG&E National Energy Group. In December 2003, I became Director of the Market

Analysis and Development department of the Midwest ISO. In October 2005, I was made Director of the Forward Markets department of the Midwest ISO and I was promoted to Executive Director Forward Markets in 2006. I have occupied my current position as Vice President of Market Operations since September 2006.

Q. PLEASE DESCRIBE YOUR JOB RESPONSIBILITIES WITH THE MIDWEST ISO AS THEY RELATE TO THIS PROCEEDING.

A. My primary responsibility at the Midwest ISO is oversight of operations of the Day Ahead Market, the Reliability Assessment Commitment function, the Financial Transmission Rights ("FTR") market, the Ex-Post Pricing function of the Real Time Market, the Resource Adequacy function, and market and tariff settlements. I am also responsible for the Midwest ISO's market analysis and development functions as well as customer management. I have actively participated in the development of all the Midwest ISO markets, from the conceptual design through delivery of market systems for implementation. I am also responsible for oversight of the Midwest ISO stakeholder process as it relates to market issues. I have participated in the development of the Midwest ISO's Open Access Transmission, and Operating Reserves Market Tariff ("Tariff") through coordination of market design activities.

Q. HAVE YOU SPONSORED ANY OTHER TESTIMONY BEFORE REGULATORY COMMISSIONS?

A. I have submitted prepared testimony before the Federal Energy Regulatory Commission ("FERC") involving matters specific to the Midwest ISO.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I will generally describe the Midwest ISO energy and ancillary services markets, and the market for FTRs how those markets operate, and the benefits of those markets for Big Rivers and its customers.

Q. PLEASE DESCRIBE THE MIDWEST ISO MARKETS.

A. System operations under the Midwest ISO's Tariff include balancing of generation supply to assure demand is satisfied in a dependable and efficient manner, and managing transmission congestion that arises due to physical limitations of the transmission system. These services are provided by the Midwest ISO through a coordinated competitive market for electric energy. This market operates on the same principles as markets for other commodities such as corn, wheat or natural gas. The Midwest ISO energy market operates by comparing offers to sell energy with bids to buy energy through a process that determines market clearing quantities and prices while assuring total demand ("load") is satisfied at the lowest possible cost. This market activity, however, honors the physical limitations of the transmission system used to deliver energy from generation to load. The process of matching supply and demand while maintaining transmission system reliability (whether performed by the Midwest ISO or a non-market operating company like Big Rivers) is referred to as "dispatch" which is simply the process of deciding which individual generators can most cost effectively meet the anticipated demand. The Midwest ISO performs its regional dispatch function using centralized security constrained economic dispatch, or "SCED." The SCED process simultaneously evaluates supply offers, demand bids and all physical characteristics of the regional transmission system. The SCED solution identifies the most cost effective dispatch, after which instructions are sent to each generator indicating whether the generating unit should inject power into the transmission system, and the quantity and timing of such injections. The Midwest ISO's energy markets currently operate over two timeframes. First is a "Day-Ahead" market, through which Market Participants ("MPs") can pre-schedule the transactions they plan to engage in on the following operating day. Second is a "Real-Time" market, where market participants can buy or sell energy to meet conditions during the operating day that may differ from those anticipated in the Day-Ahead market.

Q. WHAT SPECIFIC REQUIREMENTS WILL BE IMPOSED ON BIG RIVERS IN THE MIDWEST ISO MARKET?

A. The Midwest ISO Tariff sets forth detailed obligations of MPs. Those provisions affecting MPs are generally covered in Modules B, C, D, and E of the Midwest ISO Tariff. First, various requirements applicable to transmission service are found in Module B of the Tariff. Big Rivers' current Open Access Transmission Tariff will closely resemble Module B, which follows the FERC *pro forma* tariff.

Second, key provisions dealing with the activities and obligations of MPs in the markets, including Financial Transmission Rights, are located in Module C of the Midwest ISO Tariff. Specifically, Section 38.2.1 sets out the general rights and responsibilities of Market Participants, including the right to participate in all Market Activities, and likewise, the obligation to settle for all credits and debits associated with those Market Activities. Section 38.2.2 and Section 38.2.3 outline the qualifications and application process for becoming a Market Participant, as well as the obligations associated therewith. Section 38.2.4 sets forth the withdrawal and reapplication procedure in the event a Market Participant wishes to terminate its Market Participant status. Section 38.2.5 outlines additional obligations that each Market Participant must follow, including, but not limited to, the duty to follow Good Utility Practice and comply with all applicable laws, regulations, Commission requirements, and the operational procedures established by the Midwest ISO. Finally, Section 38.2.6 contains certain operational functions and responsibilities that each Market Participant must follow both prior to the operating day (e.g., reporting status of facilities and planned schedules) and during the operating day (e.g., implementing Reactive Supply and Voltage Control schedules; implementing dispatch instructions). The provisions setting out the rules and requirements for Financial Transmission Rights can be found in Section 42 of the Tariff.

Third, Module D sets forth the market monitoring function which provides the Independent Market Monitor ("IMM") with certain powers to monitor the actions of both the Midwest ISO and Market Participants in order to detect market manipulation. Module D also provides the IMM with authority to mitigate market power in certain circumstances. Every Market Participant should be familiar with Module D. Module E sets out the resource adequacy obligations of Load Serving Entities ("LSEs").

The various Tariff provisions are explained in greater detail in the related Business Practice Manuals ("BPMs") for each subject. The current Midwest ISO Tariff and BPMs can be found on the public web site maintained by the Midwest ISO (www.midwestmarket.org).

Q. PLEASE EXPLAIN HOW THE MIDWEST ISO MARKETS DETERMINE THE PRICE FOR ENERGY.

A. Clearing prices in the Midwest ISO Day-Ahead and Real-Time energy markets are a function of the competitive offers to sell and bids to buy electric energy, and can vary at different locations to reflect differences in the cost of meeting load at different locations due to the physical limitations of the transmission system and the varying cost structures of generators used to meet the energy balance. For example, to the extent a local load cannot be met with generation from a distant low cost coal generator because of a transmission constraint, the higher cost of serving that local load from a higher cost local generator is reflected in the price at that load location. This is referred to as Locational Marginal Pricing, or "LMP," which simply means that energy prices reflect the relative value of energy, based on where and when it is generated and where and when it is consumed. The process of determining market clearing prices in the Midwest ISO energy markets is based on the cost of the marginal generator required to meet the next megawatt of demand. This process is not unique to electric energy. Indeed, it is no different than the process used to determine prices in other commodity markets, or in non-commodity competitive markets such as those for real estate or professional services. Competitive markets are defined as processes whereby sellers attempt to maximize the value of the products they offer, buyers try to minimize their cost of acquiring those products and the competitive interaction of all buyers and sellers determines a market price at which transactions occur. This is the same process that operates to determine the prices at which a Kentucky farmer would sell agricultural products produced, whether sold at the Chicago commodity exchange or elsewhere; and the process that establishes the value of stocks and bonds in retirement funds on Wall Street. This same general market process is what is used to determine prices in the energy markets managed by the Midwest ISO. The process is not new or different for electricity wholesale markets; it is the very same process that underlies this country's economy.

Q. WON'T THE PROCESS YOU DESCRIBE RESULT IN HIGHER ENERGY PRICES FOR BIG RIVERS AND ITS CUSTOMERS?

A. No, it will not. The energy market managed by the Midwest ISO receives and promptly clears bids and offers in the energy markets, calculates LMPs, and commits and dispatches generating units, to reliably balance supply and demand at the least cost. The resulting energy prices reflect the value of generation owned and operated by companies like Big Rivers, based on competitive offers from those generation owners. To the extent Big Rivers supplies generation from owned resources to meet its load obligations, the supply cost for Big Rivers is unchanged. To the extent that Big Rivers can purchase energy from the market at prices lower than operating cost of Big Rivers' generation, Big Rivers' supply cost will be reduced. In fact, to the extent that Big Rivers has excess generation (more generation than needed to serve its customers), Big Rivers can sell that excess in a liquid market, assuring that Big Rivers realizes the full economic value of that generation. As a result, the supply cost for Big Rivers is expected to be either unchanged or lower than if Big Rivers operated outside a centrally dispatched market.

Q. WILL PRICES TO CONSUMERS BE AFFECTED BY THIS MARKET PRICING?

A. One sometimes cited but erroneous belief is that prices determined based on this process and reflecting marginal supply result in higher retail prices paid by consumers. This is also incorrect. The market clearing process is based on offers from all generators and prices are determined based on the incremental unit needed to meet current demand. For typical utilities, rates paid by retail customers reflect the average cost of generation. Although it is the case that LMPs can be expected to be higher than average system costs in many time periods, this does not result in higher customer rates. For utilities such as Big Rivers, the cost of serving load is based on the average cost of operating owned generation, regardless of market clearing prices. That is because Big Rivers' generation cost is unchanged. LMP merely reflects the economic value of energy at each location at each moment in time, but does not reflect the generation costs that are used to establish rates for Big Rivers' customers. On the other hand, as noted above, LMP market signals are important as they allow Big Rivers to reduce output and buy from the market when the market price is low and to sell excess generation into the market when the market price is higher. Market based LMPs are also helpful should Big Rivers need to purchase energy, for example, to replace supply due to a generation outage. Such purchases can be made instantaneously in a transparent liquid market at competitive prices.

Q. ISN'T THE MARGINAL SUPPLY SOURCE IN THE MARKET TYPICALLY HIGHER-PRICED GAS-FIRED GENERATION?

A. One final misconception about LMP-based markets is that the cost of purchased energy will be high because natural gas units are typically the marginal supply source. In practice, the process of determining the lowest cost dispatch and determining prices based on the marginal source of supply results in prices in the Midwest ISO energy markets based on low cost coal generation in 75% to 80% of all hours. Natural gas generation is typically used during higher demand periods and determines market clearing prices less than 25% of all hours. Thus, even though Big Rivers enjoys the advantage of being a Kentucky coal fired low cost energy producer, it will have more opportunity to sell energy to higher cost areas (without paying additional transmission charges to reach those buyers). In those limited hours when Big Rivers has no excess generation but needs additional energy to serve its load, the clearing price in the market provides greater transparency and cost savings than the traditional non-market system.

Q. PLEASE SUMMARIZE THE ADVANTAGES OF MARKET-BASED PRICING.

A. The broader market-based approach assures Big Rivers that its demand is met cost effectively by enabling competition to discipline market behavior and prices. Competitive market outcomes, and the useful information provided by Midwest ISO's transparent market operations, provide efficient price signals that, among other things: (i) highlight areas where investment opportunities are available to increase generation output at existing and/or new facilities; (ii) educate consumers and promote demand response and conservation behavior; and (iii) foster investments to build additional supply and transmission facilities to meet growing demand.

Q. PLEASE DESCRIBE THE MARKET FOR FINANCIAL TRANSMISSION RIGHTS AND ITS RELEVANCE FOR BIG RIVERS AND ITS CUSTOMERS?

A. As noted by other Midwest ISO witnesses in this proceeding, the energy markets operated by Midwest ISO also increase system reliability and reduce supply costs by managing congestion more efficiently than was possible prior to the advent of ISOs. Previously, transmission congestion was managed through a process of curtailing or limiting scheduled use of transmission facilities. This method, called transmission loading relief or "TLR," was slow and imprecise, often requiring long periods of time and several attempts to bring transmission flows within secure operating limits. The Midwest ISO energy markets operate on a five-minute basis, generating dispatch instructions that are sent to generators assuring that transmission constraints are managed precisely, quickly, and at the lowest cost. When transmission constraints occur, flows on the constrained transmission facility are reduced by dispatching generators to lower output levels on one side of the constraint and dispatching generators to higher output levels on the other side of the constraint. As a consequence, LMPs where generation is reduced tend to decline and when generation is increased tend to rise. That difference in price is the "locational" element of LMP and reflects the costs of managing transmission constraints to ensure reliable system operation within safe equipment operating limits. Differences in LMP between a specific generator and load location are referred to as congestion costs. LMP markets provide the mechanism to offset or hedge those costs through financial instruments know as FTRs. FTRs pay the holder of the right the congestion cost between a specific generator and a specific load. FTRs are defined as between specified locations, for a specified MW level, in a specific direction and for a specified time period. FTRs are allocated to firm transmission customers under the Midwest ISO tariff. FTRs may also be purchased or sold through annual and monthly FTR auctions.

Q. WILL BIG RIVERS BE ENTITLED TO FTRS AS A MEMBER OF THE MIDWEST ISO?

A. Big Rivers will be eligible to nominate and hold FTRs once it becomes a registered Market Participant and otherwise meets the Tariff's terms and conditions. In accordance with the process used to allocate transmission rights, Big Rivers will be eligible to nominate and receive both short-term and long-term transmission rights. Moreover, Big Rivers has the flexibility to choose to sell congestion rights in an FTR auction and receive the market value of the congestion rights rather than holding the FTRs. The congestion rights annual allocation and auction process occurs in the first several months of each year. To the extent that Big Rivers joins prior to the established timelines for participation in the next Annual Auction Revenue Rights ("ARR") Allocation, it will be allowed to participate in a partial-year allocation of FTRs for the remainder of the Year 1 allocation period. For that purpose, the Midwest ISO will conduct a partial year FTR allocation that will provide Big Rivers with congestion hedges for the rest of the Year 1 allocation period, covering the paths representing their historical transmission usage.

Q. WHAT PROCEDURES WILL APPLY TO THE PARTIAL YEAR FTR ALLOCATION?

A. The Midwest ISO Tariff contains the details of the partial year FTR allocation methodology, including the number of rounds or stages, and the restoration procedure, consistent with Module C of the Tariff. Since the Summer season will have just ended in September 2010, for Big Rivers integrating then, the partial year FTR allocation will include three seasons (Fall, Winter and Spring), and both peak and off-peak periods. As in the case of the ARR allocation, the allocation of FTRs to Market Participants will be capped at their annual peak Network Load and the volume of Transmission Service Reservations ("TSRs") for point-to-point Transmission Service. Subject to the availability of time, the Midwest ISO will attempt to hold the partial year FTR allocation in two stages to give applicants or Market Participants at least two opportunities to request FTRs for their transmission usage paths. As with all FTRs, any allocated partial year FTRs shall be financially binding for their entire term.

Q. WILL THE MARKET STRUCTURE YOU DESCRIBE INTERFERE WITH BIG RIVERS' POWER CONTRACTS, OR THIS COMMISSION'S AUTHORITY TO SET RATES FOR BIG RIVERS' CUSTOMERS?

A. The Midwest ISO Tariff and Business Practices recognize the existence of various wholesale power contracts, such as those between Big Rivers and its distribution cooperatives and municipal distribution utilities. Nothing I have described changes the terms or conditions of the wholesale energy portion of those contracts as long as the parties wish to retain them. Big Rivers will be the registered Market Participant under the Midwest ISO Tariff, and will offer its units into the market, and purchase energy it may require to fulfill its contracts, but the contract price established by the parties is not affected. Similarly, the Kentucky Commission establishes rates that Big Rivers is permitted to charge. Nothing I have described affects that authority. In other states in the Midwest ISO footprint, transmission owners have sought authority from their local regulators to pass on certain charges, or credits, arising from their energy and transmission service activities in the Midwest ISO. I am not aware of anything in the way Kentucky regulates Big Rivers that would be different from other states' ability to continue this practice.

Q. PLEASE SUMMARIZE MIDWEST ISO'S RESOURCE ADEQUACY CONSTRUCT.

A. The Midwest ISO does not require an LSE to procure its capacity from a centralized capacity auction like that used in PJM or ISO New England. Instead, the Midwest ISO long term resource adequacy construct[1] allows the LSE to use its own resources or procure capacity bilaterally in order to meet

[1] Module E of the Midwest ISO Tariff was approved by the Commission in *Midwest Independent Transmission System Operator, Inc.*, 127 FERC ¶ 61,054 (2009).

its Planning Reserve Margin Requirement. If an LSE does not meet its Planning Reserve Margin Requirement it will be assessed a financial charge under the terms of the Midwest ISO Tariff. The Midwest ISO determines on a monthly basis whether a LSE has met its Planning Reserve Margin Requirement. The approach of allowing LSEs to procure their own capacity has been used with success for decades by the NERC regions and planned reserve sharing groups prior to the Midwest ISO's adoption of it. The Midwest ISO performs a Loss of Load Expectation ("LOLE") study, a probabilistic analysis, annually to set the Planning Reserve Margin Requirement for the LSEs in the upcoming Planning Year (June 1 through May 31). The Planning Reserve Margin Requirement is the minimum reserves required for each LSE above its forecasted demand to meet the one day in 10 years reliability criteria. The Midwest ISO also performs a LOLE study for years 2-10 in order to provide a forward looking signal on future reserve requirements and for potential import constrained areas of the Midwest ISO. That analysis shows a projected reserve requirement of 17% on an installed capacity basis for the year 2018 to meet the 1 day in 10 year reliability criteria. This Midwest ISO Resource Adequacy Review ("RAR") construct was developed through close collaboration with the Organization of MISO States ("OMS") and our other stakeholders. In addition to the long term LOLE study, the Midwest ISO also performs a long-term reliability assessment. This assessment shows the projected demand and resources for the next ten years. The most recent Long Term Resource Assessment shows the Midwest ISO having a reserve margin of 25.5% in 2018. This most recent projection shows sufficient supply for the next 10 years.

Q. PLEASE DESCRIBE THE CURRENT RESOURCE ADEQUACY REQUIREMENTS.

A. The Midwest ISO's long-term resource adequacy plan went into effect on June 1, 2009. Module E requires LSEs to have adequate resources to meet their forecasted load, plus a planning reserve margin, which is their Planning Reserve Margin Requirement. In addition to generation capacity, acceptable resources include bilateral purchase power contracts with resources outside the Midwest ISO footprint with appropriate transmission service, demand response ("DR") resources, such as interruptible load, and behind the meter generation ("BTMG"). Midwest ISO evaluates each resource type to determine if it qualifies as capacity which can be used by an LSE to meets its Planning Reserve Margin Requirement. This Resource Adequacy construct makes LSEs accountable for procuring sufficient capacity to meet the LOLE criteria and if LSEs fail to meet their Planning Reserve Margin Requirement they will be assessed an administrative deficiency charge equal to the "cost of new entry" ("CONE"). The CONE is calculated annually with the Independent Market Monitor. The calculation of CONE includes physical factors such as type, location, fuel cost, and financial factors such as cost of capital, operating, and others costs.

The Midwest ISO's Resource Adequacy construct is premised on LSEs historically meeting their planning reserve requirements primarily using their own supply or bilateral contracts and is consistent with a market (spanning multiple state and local jurisdictions) predominantly managed by traditional, vertically-integrated utilities. In this role, the Midwest ISO, through its stakeholder planning meetings, determines a number of critical components of the resource adequacy requirements, including the calculation of a loss of load expectation to determine the Planning Reserve Margin Requirement which I mentioned previously, diversity factors, individual unit unforced capacity ratings, accreditation and confirmation of Demand Resources, BTMG and External resources, and strenuous after-the-fact measurement and verification of generator performance, emergency availability compliance, load forecast error, unit testing, must-offer requirement compliance and reporting requirements to states in the Midwest ISO footprint.

In particular, the Midwest ISO provides market mechanisms that allow Demand Resources, BTMG and External Resources to participate on a level playing field with generators in the various products and services it offers, consistent with the laws of the jurisdiction where those resources are located. Altogether, the Midwest ISO estimates that over 9,000 MW of Demand Resources and BTMG are registered for capacity credit as Load Modifying Resources with the Midwest ISO.

Q. WHAT BENEFIT DOES A REGIONAL RESOURCE ADEQUACY CONSTRUCT PROVIDE FOR MEMBER ENTITIES?

A. Within Module E, individual LSEs maintain reserves based on their monthly peak load forecasts. The sum of the LSEs' peak forecasts do not sum to Midwest ISO system coincident peak because they are reported based solely on each entity's own peak, which could occur at a different time than the system peak. To account for this diversity within Midwest ISO, a reserve margin was calculated for application to individual LSE peaks utilizing a 2.35% diversity factor for the first planning year (June 2009 - May 2010) and a 3.00% diversity factor for the second planning year (June 2010 - May 2011). This resulted in an individual LSE reserve level of 12.69% for the first planning year and an even lower reserve level of 11.94% for the second planning year, reduced from what would otherwise be a 15.4% reserve without accounting for diversity.

This diversity factor is the primary calculation component of the Midwest ISO's Value Proposition - Generation Investment Deferral. The lower planning reserve margin calculated as result of the regional diversity by the Midwest ISO translates into the deferral of constructing new electric generating resources in the future. In addition, allowing alternative resources like Demand Resources and BTMG to be used to meet an LSE's resource adequacy obligations further enhances the value proposition. This in turn reduces the capital cost for new generation to be recovered from end use customers. The shift from localized use of the electrical system to regional use allows more efficient and effective use of the generation assets and allows for a reduction in the planning reserve margins for the region. The Resource Adequacy benefits are reflected in "Generator Availability Improvement" in Midwest ISO's 2009 Benefit Proposition Study, which are discussed in Midwest ISO Witness Moeller's testimony.

Q. DOES THE MIDWEST ISO HAVE A CAPACITY AUCTION LIKE PJM?

A. No. PJM calculates the necessary planning reserve margin, and PJM acts on behalf of the LSEs and bids in an auction to procure capacity from generation owners. However, as part of the Midwest ISO Resource Adequacy construct, the Midwest ISO does conduct a monthly *Voluntary* Capacity Auction ("VCA") for those entities that were unsuccessful at procuring sufficient capacity through bilateral arrangements or self-supply. The VCA is designed to be "a useful alternative option for obtaining capacity in the Midwest ISO, with the primary instrument still being bi-lateral transactions" (quoting the FERC order approving Module E).

Q. HOW DOES MISO MEMBERSHIP AFFECT BIG RIVERS' INTEGRATED RESOURCE PLANNING PROCESS AND THE KENTUCKY PUBLIC SERVICE COMMISSION'S REVIEW OF THE BIG RIVERS PLAN?

A. Module E need not have any effect on a state's integrated resource planning process. The Midwest ISO does not do integrated resource plans. The Commonwealth of Kentucky is free to establish a different planning reserve margin if it chooses to do so. The Midwest ISO calculated planning reserve margin becomes the default value if no other margin is set by the regulatory authority, or if the state commission affirmatively selects the Midwest ISO margin, as all states have done to date.

Q. HOW CAN THIS COMMISSION BE ASSURED THAT THE MIDWEST ISO MARKETS ARE AND WILL REMAIN COMPETITIVE?

A. The Midwest ISO energy markets include safeguards to assure they remain competitive under all conditions. The Midwest ISO has an IMM that monitors, reports and mitigates potential or actual attempts to exercise market power, or any inappropriate manipulation, gaming or abuse of the energy markets. The IMM's responsibilities include the designation of local areas characterized by significant transmission constraints (known as Broad Constrained Areas or "BCAs," and Narrow Constrained Areas or "NCAs.") FERC approved the IMM's designation of NCAs in 2004 and 2006; and last year, FERC accepted the IMM's recommendation to permanently establish the Tariff's provisions for BCA mitigation measures. The IMM has the authority to limit maximum allowable offers and therefore maximum price in such local constraint areas. The market monitoring and mitigation measures in the Midwest ISO energy market include constant monitoring and immediate mitigation when warranted, thereby removing the ability to exercise market power and assuring that the market remains competitive. Further, the Midwest ISO's tariff requires the IMM to not only monitor and mitigate, but also to report instances of potential market power abuse to the FERC, which may refer, either based on the IMM's reports or upon complaint by other market participants, this conduct to the FERC's enforcement staff for further investigation and punitive action.

In addition, the IMM and the Midwest ISO analysts, in concert with stakeholder efforts, continually analyze the various markets in ongoing support of competitive markets. The Midwest ISO makes FERC filings when market design elements are identified that require improvement.

Q. WILL THE MIDWEST ISO MARKET BENEFIT BIG RIVERS' MEMBERS AND CUSTOMERS?

A. The broader regional scope of the Midwest ISO's transmission system and energy market operations provides market participants with a wider range of options for buying or selling power than previously existed. The Midwest ISO continually seeks to enhance its market services and the value those services bring to the region. The Midwest ISO's market participants include traditional integrated utilities, municipalities, cooperatives and other public entities, alternative retail suppliers, independent power producers, energy marketers and others. The competitive energy markets operated by the Midwest ISO assure that those serving load can cost-effectively procure wholesale power and pass on resulting savings to their customers. Accordingly, the Midwest ISO believes its energy markets will help enhance the value of Kentucky's retail electric energy service.

Q. WHAT IS DEMAND RESPONSE AS IT RELATES TO THE MIDWEST ISO WHOLESALE MARKETS?

A. "Demand response" refers to the ability of a MP to reduce its electric consumption in response to an instruction, signal or information received from the Midwest ISO. Market Participants can provide such demand response in Midwest ISO markets either with discretely interruptible or continuously controllable loads ("Demand Resources") or with behind-the-meter generation and are compensated by the Midwest ISO for providing such load reductions to the market.

Q. WHO IS ELIGIBLE TO PARTICIPATE IN THE MIDWEST ISO WITH WHOLESALE DEMAND RESPONSE?

A. Three types of market participants may provide demand response in the Midwest ISO:

- Load Serving Entities ,
- Aggregators of Retail Customers ("ARCs")[2], and
- End-use customers that have Market Participant status.

Q. WHAT ARE THE DEMAND RESPONSE SERVICES OFFERED BY THE MIDWEST ISO AS PART OF ITS TARIFFED WHOLESALE MARKETS?

A. The Midwest ISO employs demand response to:

- reduce loads whose values to end use customers are less than the costs of serving those loads (i.e., *Economic Demand Response*);
- provide Regulation or Contingency Reserves (i.e., *Operating Reserve Demand Response*);

---

[2] Implementation of ARCs into the Midwest ISO markets has a start date of June 1, 2010, dependent upon FERC approval of filed Tariff language.

- reduce demand during system Emergencies (i.e., *Emergency Demand Response["EDR"]*); and
- substitute for generating capacity (i.e., *Planning Resources Demand Response*).

Demand response has the duplicate benefit of reducing the demand at critical times as well as benefiting customers by enhancing the competitive markets through downward price pressure on the affected LMPs. I will describe in further detail each of these general categories of demand response.

Q. WHAT IS ECONOMIC DEMAND RESPONSE?

A. A Demand Response Resource ("DRR") is a demand resource or behind-the-meter-generator that can respond to the dispatch instructions of the Midwest ISO. DRRs are the only demand resources that can "inject" Energy on an economic basis, i.e., to replace higher-priced Energy offered by generators.[3] There are two types of DRRs under the Midwest ISO Tariff:

- A ***DRR – Type I*** is capable of supplying a fixed, pre-specified quantity of Energy, through physical load reduction, to the Energy and

[3] Additionally, the Market Participant with demand response assets is free to manage its purchases of energy in the Midwest ISO markets by self-scheduling its demand resource assets, or controlling its metered load by calling on its demand resource assets directly, to mitigate potential price exposures in the markets or to address local reliability concerns.

Operating Reserve Market when instructed to do so by the Midwest ISO.

- A ***DRR – Type II*** is capable of supplying a range (continuum) of Energy, through physical load reduction or behind-the-meter generation, to the Energy and Operating Reserve Market and is capable of complying with the Midwest ISO's set-point Instructions.

MPs may submit DRR Offers into the Day-Ahead Market and/or the Real Time Market. DRR Offers submitted to these two markets are mutually independent, i.e., the price-quantity schedules offered into one market do not have to be equal to the schedules offered into the other market. MPs with DRR offers that clear the market, and that subsequently follow Midwest ISO dispatch instructions within acceptable tolerances, are paid the hourly LMPs for the Energy they returned to the market through their load reductions. In addition, they are made whole for their one-time shutdown costs if committed by the Midwest ISO through its SCUC process (except for "must run" offered resources, which are not entitled to recovery of shutdown costs). However, for DRRs, the MPs are charged for acquiring the Energy they "injected" into the market. This charge is applied because a demand resource cannot produce Energy; it can only "inject" Energy that would have otherwise been delivered to it for consumption. The LSE within which the load reduction occurred is charged for the demand responder price settlements.

Q. WHAT IS OPERATING RESERVE DEMAND RESPONSE?

A. Operating Reserve Services take on three forms:

- Regulation Service;
- Spinning Reserve Service; and/or
- Supplemental Reserve Service.

Together, Spinning Reserve and Supplemental Reserve are also known as Contingency Reserve. In addition to providing Energy, DRR-Type I and DRR-Type II resources that are technically qualified to do so may provide one or more forms of Operating Reserve Service. DRR-Type I Resources can provide either Energy or Contingency Reserve Service, but cannot simultaneously provide both. DRR Type II Resources may provide Energy and/or one or more Operating Reserve products simultaneously.

Q. WHAT IS EMERGENCY DEMAND RESPONSE?

A. MPs with Demand Resources and/or BTMG (the MP's EDR resources) that do not qualify as DRRs, or that are not offered into the Energy or Operating Reserve Markets, can still offer to reduce their gross loads when the Midwest ISO declares an Energy Emergency event (e.g., NERC Energy Emergency Alert ("EEA)"). The Midwest ISO's Emergency Demand Response Initiative allows, but does not require, EDR resources to provide Emergency Demand Response during such events unless they are also claiming capacity credit as Planning Resources. Each day an MP can decide how much of each of its

EDR resources to make available to the Midwest ISO for EDR service the following day, and at what prices. In addition to providing hourly curtailment prices in its daily EDR Offer, the MP can also specify one-time shutdown cost and a number of operational constraints for each EDR resource. When an Emergency event occurs, the Midwest ISO will use the information in the EDR Offers to decide the order in which to curtail the associated EDR resources and to determine a single market-clearing price to be paid for the curtailments.

Q. CAN DEMAND RESPONSE BE USED AS A PLANNING RESOURCE?

A. Yes. Load Modifying Resources ("LMRs") and DRRs can qualify as Planning Resources if the MP registering those assets commits in advance to using them to reduce its gross load when instructed to do so by the Midwest ISO during an Energy Emergency event. Module E of the Midwest ISO Tariff prescribes how DRRs and LMRs are accredited as Planning Resources based on their "unforced" capacities. LMRs and DRRs have monetary value because they can be substituted for Generation Resources by an LSE in meeting its assigned Planning Reserve Margin Requirement ("PRMR").

Q. DOES THE MIDWEST ISO DEMAND RESPONSE CONSTRUCT CONFLICT WITH STATE REGULATORY REQUIREMENTS?

A. No. In addition to the Midwest ISO's own standards and requirements for Demand Response participation in its wholesale markets, the states within the Midwest ISO Region may also have various requirements and regulations that must be met regarding the participation and use of Demand Response by the qualified Market Participant. The Midwest ISO acknowledges the important role that state regulatory authorities play, in collaboration with FERC, and has and continues to develop its Demand Response initiatives to be consistent and compliant with both federal and state requirements. For example, some state regulatory authorities currently do not allow ARCs to do business with retail customers served by LSEs subject to their jurisdiction. Such prohibitions may also be imposed by authorities having regulatory control over public power entities and cooperatives which may be outside the jurisdiction of state regulators.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

VERIFICATION

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

RD

Richard Doying

STATE OF INDIANA)

COUNTY OF HAMILTON)

SUBSCRIBED AND SWORN TO before me by Richard Doying on this 29 day of January, 2010.

Christi Tinch

Notary Public

Christi Tinch

My Commission Expires: Aug. 15, 2013

My County of Residence: Hamilton

MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.
MEMBERSHIP APPLICATION FOR
TRANSMISSION FACILITIES OWNER

1. Applicant's Full Legal Name: Big Rivers Electric Corporation
   a. Main Office Address: 201 Third Street
      Henderson, KY 42420
   b. Main Office Telephone Number: ______
   c. Applicant is *(please check appropriate category below)*
      ○ A corporation organized under the laws of ______
      ○ A partnership organized under the laws of ______
      ○ A cooperative organized under the laws of ______
      ○ A political subdivision of ______
      ◉ Other *(please describe)* Electric Coop Corp. organized under the laws of Commonwealth of KY
   d. Applicant presently operates as: Rural Electric Generation and Transmission Cooperative

      (e.g., Rural Electric Cooperative, Cogenerator, Exempt Wholesale Generator, Municipal Utility, Power Marketing Administration, Vertically Integrated Utility)
   e. Applicant's geographical area of operation: provides most of the wholesale power requirements of its three memeber distribution cooperatives, which operate entirely in Western KY
   f. Is Applicant associated with another entity that is already a Member of the Midwest ISO and which has the same parent corporation? If so, please describe:
      No

2. As a Transmission-Owning Member of the Midwest ISO, the Applicant herein agrees to fully execute and submit a signature page to the Agreement of Transmission Facilities Owners to Organize the Midwest Independent Transmission System Operator, Inc., A Delaware Non-Stock Corporation ("Midwest ISO Agreement"), FERC Electric Tariff, First Revised Rate Schedule No. 1.

3. As a Transmission-Owning Member of the Midwest ISO, the Applicant herein agrees to fully execute and submit a signature page to the Appendix I Supplemental Agreement by and between the Midwest ISO, International Transmission Company and each of the Midwest ISO Transmission Owners ("Appendix I Supplemental Agreement").[1]

4. As a Transmission-Owning Member of the Midwest ISO, the Applicant herein agrees to enter into an Agency Agreement pursuant to Appendix G of the Midwest ISO Agreement to authorize the Midwest ISO to act as its agent in the performance of tariff administrative duties with regard to Non-transferred Transmission Facilities.

---

1 The Appendix I Supplemental Agreement was approved by the Federal Energy Regulatory Commission on December 20, 2001. *See, International Transmission Company, et al.*, 97 FERC ¶ 61,328 (2001). Pursuant to Section 3.5 of the Supplemental Agreement, any person or entity seeking to join the Midwest ISO as an Owner shall, as a condition to being granted ownership status, be required to sign the Appendix I Supplemental Agreement and be bound by all of its

Exhibit 8

terms and conditions.

5. Persons authorized by Applicant herein to vote on matters at the Midwest ISO and to whom official correspondence will be sent to (Please include the name of one officer):

a. Name: Mark Bailey
(1) Title President & CEO
(2) Address: 201 Third Street, Henderson, Kentucky 42420
(3) Telephone 270-827-2561
(4) FAX: 270-827-2558
(5) Email Mark.Bailey@bigrivers.com

b. Name: William (Bill) Blackburn
(1) Title Senior Vice President of Energy Services & CEO
(2) Address: 201 Tjord Street, Henderson, Kentucky 42420
(3) Telephone 270-827-2561
(4) FAX: 270-827-2101
(5) Email Bill.Blackburn@bigrivers.com

c. Name: David Crockett
(1) Title Vice President System Operations
(2) Address: 201 Third Street, Henderson, Kentucky 42420
(3) Telephone 270-827-2561
(4) FAX: 270-827-0183
(5) Email David.Crockett@bigrivers.com

6. Applicant herein selects the following sector for representation and voting purposes at the Midwest ISO Advisory Committee Meetings (please check one category below):

- (●) Transmission Owner;
- ( ) Independent Power Producers and Exempt Wholesale Generators;
- ( ) Power Marketers and Brokers;
- ( ) Municipals, Cooperatives and Transmission Dependent Utilities;
- ( ) Public Consumer Advocates;
- ( ) State Regulatory Authorities;
- ( ) Environmental/Other Advocates;
- ( ) Eligible End Use Customers.

7. Membership Fee:

Note: Pursuant to Article Six of the Midwest ISO Agreement, "[a]ll entities eligible for membership in the Midwest ISO shall pay an initial membership fee of $15,000 in order to become Members. . . . All such fees are nonrefundable and may be adjusted from time-to-time, as may be appropriate by the Board."

This fee was specifically approved by the Federal Energy Regulatory Commission in its Order conditionally approving the establishment of the Midwest ISO. See, Order Conditionally Authorizing Establishment of Midwest Independent Transmission System Operator and Establishing Hearing Procedures, *Midwest Indep. Transmission Sys. Operator, Inc.*, Docket No. ER98-1438-000, 84 FERC ¶ 61,231 (1998). The Commission also stated that "there is no restriction in the Midwest ISO Agreement to preclude potential Members from pooling financial resources to pay the application fee and annual dues, i.e., have a collective membership interest."

Each Applicant shall submit with its application a check made payable to Midwest Independent Transmission System Operator, Inc. in the amount of $15,000.

If the Applicant consists of several entities or individuals who wish to share a membership, the $15,000 membership fee will cover the entire group's membership; however, the group will be entitled to only one (1) vote.

The Midwest ISO requires all entities eligible for membership to pay the $15,000 fee if they desire to participate in the election of the Board of Directors. This policy will apply to the original signatories to the Midwest ISO Agreement, as well as to any subsequent signatories or other entities who apply for membership and agree to be bound by the terms of the Midwest ISO Agreement, as amended.

This application and the membership fee shall be forwarded via Federal Express or Certified Mail to:

Stephen Kozey
General Counsel
Midwest ISO
701 City Center Drive
Carmel, IN 46032

(317) 249-5400 (Telephone)
(317) 249-5912 (FAX)
skozey@midwestiso.org (Email)

Mark A. Bailey
(Signature)
Mark A. Bailey
(Print name)
Title: President & CEO
Date: 12/7/07

MEMORANDUM OF UNDERSTANDING

This Memorandum of Understanding ("Memorandum"), entered into on December 11, 2009, by and between the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") and Big Rivers Electric Corporation ("Big Rivers"), individually and collectively referred to herein as "Party" or "Parties," is intended to establish the parameters governing the integration of the transmission facilities of Big Rivers into the transmission grid operated by the Midwest ISO. Pursuant to this understanding, the Midwest ISO and Big Rivers do represent and acknowledge as follows:

FIRST, the Midwest ISO is a non-stock, non-profit corporation organized under the laws of Delaware, and a regional transmission organization ("RTO"), as established by the Federal Energy Regulatory Commission ("FERC") pursuant to Order No. 2000;

SECOND, Big Rivers is a cooperative association organized and existing under the laws of the State of Kentucky that provides electric service to its member cooperatives and certain municipal utilities located in the state of Kentucky; and owns or operates transmission facilities that are contiguous to the transmission facilities that are presently subject to the functional control of the Midwest ISO;

THIRD, Big Rivers has stated its intention to join the Midwest ISO as a Transmission Owner within the scope of the Agreement of Transmission Facilities Owners to Organize the Midwest Independent Transmission System Operator, Inc., a Delaware Non-Stock Corporation ("Midwest ISO TOA");

FOURTH, the Parties agree that a phased integration of its transmission facilities, beginning with the ability for Big Rivers to obtain certain RTO and ancillary market services

EXHIBIT 9

on January 1, 2010, and concluding with full integration of the Big Rivers transmission facilities on September 1, 2010;

NOW, in consequence thereof, the Parties agree as follows with respect to those activities necessary to effectuate the Big Rivers membership in the Midwest ISO.

1. Cost of Application and Integration

1.1 The Parties acknowledge that approval by the FERC pursuant to Section 205 of the FPA will be necessary to implement certain changes to the Midwest ISO's Open Access Transmission, Energy and Operating Reserves Markets Tariff ("Midwest ISO Tariff"), including, without limitation, Attachment O containing the Big Rivers transmission cost of service, and, if necessary, Attachment P to reflect certain Big Rivers Grandfathered Agreements ("GFAs"). The Parties further acknowledge that the Midwest ISO will be required to expend considerable resources in order to prepare and defend applications and other filings associated with the Big Rivers membership, to integrate the facilities of Big Rivers into the transmission grid that it presently operates, to include Big Rivers load into the commercial model underpinning its Energy and Operating Reserves Markets, to assign Auction Revenue Rights ("ARR") and Financial Transmission Rights, and to permit the phased integration requested by Big Rivers beginning January 1, 2010. In consideration of these efforts, Big Rivers agrees to work in good faith with the Midwest ISO to determine, agree upon, and reimburse the Midwest ISO for its reasonable cost of attorney fees, related legal expenses attributed to the Big Rivers integration, and the reasonable quantifiable cost of Midwest ISO internal employee wages and overheads for such integration efforts in the event that Big

Rivers elects not to integrate its facilities with the transmission system operated by the Midwest ISO.

1.2 Notwithstanding the provisions of Section 1.1, each Party will bear its own costs in the event that: (a) the FERC does not accept the Section 205 applications necessary to effectuate integration or attaches conditions that are reasonably deemed by Big Rivers to be unacceptable; (b) applicable regulatory authorities (which shall include for purposes of this Memorandum any Big Rivers creditor whose consent is required under financing documents), if any, deny Big Rivers permission to transfer functional control of its transmission assets to the Midwest ISO, or attach conditions reasonably deemed by Big Rivers to be unacceptable; or (c) the FERC and all other applicable regulatory authorities approve the transfer of functional control or other requirements needed to integrate, and the Big Rivers facilities are integrated, into the Transmission System of the Midwest ISO. Big Rivers will advise the Midwest ISO in writing of conditions imposed by the FERC or any applicable regulatory authority deemed to be unacceptable within thirty (30) days of the issuance of the order imposing such conditions.

2. Other Authorizations

2.1 Concurrent with or prior to the submission of the necessary FPA Section 205 filings with the FERC, Big Rivers will initiate such activities as may be necessary to secure any applicable regulatory approval to transfer functional control of its transmission assets to the Midwest ISO, including preparation of any necessary regulatory filings. The Midwest ISO will provide any reasonable assistance to Big Rivers necessary to prepare and perfect its application(s) to such regulatory authorities and otherwise support the regulatory approval process as Big Rivers may reasonably request.

2.2 Big Rivers will pursue such approvals with diligence and will not to take any action that would prejudice regulatory approval of its application(s). Should Big Rivers not pursue state applications diligently, or should it take action that would prejudice approval, then Big Rivers shall be liable for the integration costs incurred by the Midwest ISO as set forth in Section 1.1 of this Memorandum, notwithstanding the proviso of Section 1.2 set forth above.

3. Relationship With Non-Jurisdictional Entities

3.1 To the extent any non-jurisdictional entity whose transmission facilities are integrated with, or embedded into, the Big Rivers transmission facilities: (a) declines to transfer functional control of its transmission facilities to the Midwest ISO; (b) objects to the functional control of the Big Rivers transmission facilities by the Midwest ISO; or (c) asserts that it will be due compensation from Big Rivers or the Midwest ISO for service over such integrated or embedded facilities, Big Rivers shall so advise the Midwest ISO in writing as soon as it becomes aware of the non-jurisdictional entity's position. The Parties agree to work cooperatively to resolve any issues that may arise in connection with the non-jurisdictional entity's position, including, without limitation, by jointly supporting and defending before the FERC any needed revisions to jurisdictional agreements between Big Rivers and such a non-jurisdictional entity.

4. GFAs and ARR Allocations

4.1 The Midwest ISO and Big Rivers will work cooperatively with each other, and with third parties to GFAs, to determine the appropriate treatment of each such agreements under the Midwest ISO Tariff. The Midwest ISO and Big Rivers will further work together to determine ARR allocations to and within the Big Rivers Zone. The Parties understand that any unresolved issues relating to GFAs or ARR allocations are subject to FERC jurisdiction.

5. Membership and Withdrawal Obligations

5.1 The Parties agree that Big Rivers will become a member of the Midwest ISO upon its execution of the Midwest ISO TOA which sets forth the respective rights, duties and obligations of a member. Consistent with the Midwest ISO TOA, until such time as the Big Rivers facilities are physically integrated with the transmission system operated by the Midwest ISO, Big Rivers only financial obligations associated with withdrawal as a member of the Midwest ISO shall be as set forth in Section 1.1 of this Memorandum. Big Rivers shall not be subject to the financial obligations associated with withdrawal under Articles V and VII of the Midwest ISO TOA or the time limits on withdrawal as set forth in Article V of the Midwest ISO TOA, provided, however that withdrawal shall be effective thirty (30) days after the receipt of such notice by the Midwest ISO. In the event Big Rivers elects to take any Midwest ISO tariff service during the period in which it perfects its withdrawal from the Midwest ISO, it shall pay the applicable charges therefore. After the facilities of Big Rivers are integrated with the Transmission System, the financial and withdrawal obligations of Big Rivers shall be as set forth in the Midwest ISO TOA, and not this Paragraph 5.

5.2 In the event of any conflict between the terms of this Memorandum and the terms of the Midwest ISO TOA, the terms of this Memorandum shall govern.

6. Miscellaneous

6.1 This Memorandum sets forth the basic understanding between the Parties as they undertake certain actions related to the Big Rivers planned membership in the Midwest ISO but the actual terms and conditions of the Big Rivers membership after physical integration of the Big Rivers transmission system will be governed by the Midwest ISO TOA and not this Memorandum. The terms and conditions of Big Rivers membership prior to physical integration of the Big Rivers transmission system will be governed by this Memorandum and by the Midwest ISO TOA (subject to the limitations set forth in Sections 5.1 and 5.2 of this Memorandum). This Memorandum shall not be amended unless such amendment is agreed in writing by duly authorized representatives of the Parties.

6.2. Definitions. All capitalized terms shall be as defined herein. To the extent any capitalized term is not defined herein, it shall have the meaning as set forth in the Midwest ISO Tariff.

6.3 Termination. This Memorandum shall terminate and its provisions shall cease to apply to the Parties at such time as either: (1) the Big Rivers facilities are physically integrated with the Transmission System operated by the Midwest ISO; or (2) thirty (30) days after the receipt by the Midwest ISO of Big Rivers' notice of withdrawal pursuant to Section 5.1, and, accordingly, upon the payment of any obligations that may be due under Section 1.1., the Parties shall have no further obligations to each other hereunder.

MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.

Name: ______________

Title: President and CEO

Date: Dec. 11, 2009

BIG RIVERS ELECTRIC CORPORATION

Name: Mark A. Bailey

Title: President and CEO

Date: December 4, 2009