ORIGINAL

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

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APR 02 2012

PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

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

FILED: April 2, 2012

ORIGINAL

SULLIVAN, MOUNTJOY, STAINBACK & MILLER PSC
ATTORNEYS AT LAW

Ronald 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
Mary L. Moorhouse

April 2, 2012

RECEIVED
APR 02 2012
PUBLIC SERVICE COMMISSION

Via Federal Express

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

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

Dear Mr. DeRouen:

Enclosed for filing are an original and ten copies of Big Rivers Electric Corporation's application seeking approval of a new environmental compliance plan; approval of revisions to its environmental surcharge tariff, monthly reporting forms, and related tariff billing forms; certificates of public convenience and necessity for projects contained in the new environmental compliance plan; and authority to establish a regulatory account. A copy of this letter and a copy of the application have been served on each of the persons listed on the enclosed service list.

Sincerely,

Tyson Kamuf

TAK/ej
Enclosures

cc: Mark A. Bailey
Albert Yockey

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

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

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PSC Case No. 2012-00063

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ORIGINAL

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

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

FILED: April 2, 2012

ORIGINAL

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Application of Big Rivers Electric Corporation for Approval of its 2012 Environmental Compliance Plan, for Approval of its Amended Environmental Cost Recovery Surcharge Tariff, for Certificates of Public Convenience and Necessity, and for Authority to Establish a Regulatory Account	)	Case No. 2012-00063

Application

1. Big Rivers Electric Corporation ("*Big Rivers*"), by counsel, hereby submits this application ("*Application*") pursuant to KRS 278.020, KRS 278.180, KRS 278.183, KRS 278.220, 807 KAR 5:001 Sections 8 and 9, 807 KAR 5:011, and all other applicable statutes and regulations, seeking approval of a new environmental compliance plan, approval of revisions to its environmental surcharge tariff, monthly reporting forms, and related tariff billing forms, certificates of public convenience and necessity ("*CPCNs*"), authority to establish a regulatory asset for its costs associated with this case, and authority to recover such costs through its environmental surcharge tariff.

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. 807 KAR 5:001 Section 8(1). 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 members, 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 112,000 consumer/members located in 22 Western Kentucky counties: Ballard, Breckenridge, Caldwell, Carlisle, Crittenden, Daviess, Graves, Grayson, Hancock, Hardin, Henderson, Hopkins, Livingston, Lyon, Marshall, McCracken, McLean, Meade, Muhlenberg, Ohio, Union and Webster.

3. 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*, Kentucky Public Service Commission ("*Commission*" or "*PSC*") Case No. 2005-00532, and are incorporated herein by reference. 807 KAR 5:001 Section 8(3).

4. Big Rivers gave notice to the Commission of its intent to file this Application more than 30 days prior to filing it in accordance with KRS 278.180, KRS 278.183, and 807 KAR 5:011 Section 8. Big Rivers' notice to the Commission is attached hereto as Exhibit 1. Big Rivers also mailed a notice to each of its Members no later than the date of the filing of this Application. The notice to the Members included the estimated amount of increase per customer class, along with the other information required by 807 KAR 5:011 Section 8. Big Rivers has also posted a copy of the notice to the Members at its place of business, and a copy of that notice is attached hereto as Exhibit 2.

5. This Application and the supporting exhibits, which are incorporated herein by reference, contain fully the facts on which the relief requested by Big Rivers is based. 807 KAR 5:001 Section 8(1).

Amendment of Big Rivers' Environmental Compliance Plan and Environmental Cost Recovery Surcharge Tariff

6. Big Rivers has an existing environmental compliance plan ("*Existing Plan*") and environmental surcharge tariff, both of which the Commission approved in its Order dated June 25, 2008, in *In the Matter of: The Application of Big Rivers Electric Corporation for Approval of Environmental Compliance Plan and Environmental Surcharge Tariff*, PSC Case No. 2007-00460. The Existing Plan consists of a program to control sulfur dioxide, a program to control nitrous oxides, and a program to control sulfur trioxide; and Big Rivers' current environmental surcharge tariff is a mechanism to recover, on a per kilowatt hour basis, certain operation and maintenance ("*O&M*") costs relating to the control of those pollutants under the Existing Plan.

7. New and pending environmental regulatory requirements under the Federal Clean Air Act as amended, which apply to coal combustion wastes and by-products from facilities utilized for production of energy from coal (including the proposed Cross-State Air Pollution Rule ("*CSPAR*") and the national emission standards for hazardous air pollutants, also known as the Mercury and Air Toxics Standard ("*MATS*") rule, will require Big Rivers to install new pollution control facilities. After investigating numerous alternatives, Big Rivers developed a reasonable and cost-effective plan for complying with those regulatory requirements. That new environmental compliance plan (the "*2012 Plan*"), a copy of which is attached as Exhibit Berry-2 to the Direct Testimony of Robert W. Berry (which is attached hereto as Exhibit 4), is to construct new pollution control facilities. The 2012 Plan is in addition to the Existing Plan and is further described in Mr. Berry's testimony. The 2012 Plan lists the new facilities that are needed, the pollutant each new facility is designed to control, the environmental regulation that gives rise to the need for each facility, the generating plant at which each facility will be installed, the environmental permit that each facility requires, the anticipated completion date for

each facility, and the estimated capital and O&M costs for each facility. Mr. Berry's testimony and the Direct Testimony of Thomas L. Shaw, which is attached hereto as Exhibit 6, further describe the pollution control projects contained in the 2012 Plan and relevant environmental regulations that impact Big Rivers, and demonstrate how the proposed construction projects are necessary for Big Rivers' compliance with the requirements of those regulations. Mr. Berry and Mr. Shaw describe the development of the 2012 Plan and explain that it is based upon a study by Sargent and Lundy, LLC ("*S&L*"). The S&L study is further described in the Direct Testimony of William DePriest, which is attached hereto as Exhibit 5.

8. Under KRS 278.183, Big Rivers is entitled to current recovery of its costs for the projects contained in the 2012 Plan. Big Rivers' existing environmental surcharge tariff only includes recovery of O&M costs. As the 2012 Plan includes capital projects, Big Rivers is seeking approval of a revised environmental surcharge tariff to allow for the recovery of a reasonable rate of return on its capital expenditures. The revised tariff also allows for the recovery of the operating costs associated with both the programs in the Existing Plan as well as the projects in the 2012 Plan. The operating costs that will be recovered through the environmental surcharge include all O&M costs, property taxes, property insurance, depreciation expenses, and other costs, as these costs relate to Big Rivers' Existing Plan (which only includes O&M costs) and Big Rivers' 2012 Plan.

9. The revised tariff will allocate costs based on a rolling 12-month average of Total Adjusted Revenues, which is similar to the methodology used by the other regulated utilities in Kentucky. The revised tariff will not include any costs already recovered through Big Rivers' base rates. Big Rivers is also seeking approval of related changes to certain tariff billing forms. Big Rivers' revised tariff and revised billing forms are attached as Exhibit Wolfram-2 to the

Direct Testimony of John Wolfram (which is attached hereto as Exhibit 8). Big Rivers is seeking approval of its revised tariff under 807 KAR 5:011 Section 6(3)(b) and KRS 278.183, and the revised tariff has an effective date of May 2, 2012. Mr. Wolfram's testimony describes the changes Big Rivers proposes to its environmental surcharge tariff, the mechanics of the revised tariff, and Big Rivers' determination of its proposal for a reasonable return on compliance-related capital expenditures. Mr. Wolfram's testimony and the Direct Testimony of Mark A. Hite, which is attached hereto as Exhibit 7, explain Big Rivers' plan for the reporting and accounting of environmental compliance costs. Those testimonies and the other direct testimonies filed with this Application describe the development of the 2012 Plan and otherwise support the reasonableness and cost-effectiveness of the 2012 Plan and the revised environmental surcharge tariff. The Commission should approve the 2012 Plan and the revised environmental surcharge tariff under KRS 278.183.

10. Big Rivers also requests the Commission's approval of revisions to the monthly environmental surcharge reporting forms it files with the Commission to make them consistent with the revised environmental surcharge tariff. The proposed forms are attached as Exhibit Wolfram-5 to Mr. Wolfram's testimony.

Certificates of Public Convenience and Necessity

11. To comply with the requirements of the CSAPR and MATS regulations, Big Rivers proposes to construct the projects listed in its 2012 Plan. The facts relied upon to show that the proposed construction projects are or will be required by public convenience and necessity are contained in this Application and the exhibits hereto. 807 KAR 5:001 Section 9(2)(a).

12. Big Rivers has not yet obtained the permits required for the construction projects. The permits Big Rivers will need include revisions to its Title V permits and construction permits. No franchises from any other public authority are required for the proposed construction projects. 807 KAR 5:001 Section 9(2)(b).

13. The projects consist of pollution control equipment that will be installed at the generating units listed on the 2012 Plan. Those units include Unit 1 at Big Rivers' D.B. Wilson station; Units 1 and 2 at Big Rivers' Robert D. Green station; Unit 1 at Big Rivers' Robert A. Reid station; Units 1, 2, and 3 at Big Rivers' Kenneth C. Coleman station; and Units 1 and 2 at the generating station known as "*Station Two*," which is owned by the City of Henderson, Kentucky ("*Henderson*"), and operated by Big Rivers. Engineering and design for the construction of the projects has not yet been completed. To the extent known, the manner in which the pollution control equipment will be constructed is described in Mr. Berry's testimony. The proposed construction is not likely to compete with any other public utilities, corporations, or persons. 807 KAR 5:001 Section 9(2)(c).

14. Attached as Exhibit 3 to the original and each of the ten copies of this Application being filed with the Commission are topographical maps of each generating station at which Big Rivers will install the pollution control equipment. There are no like facilities owned by others located anywhere within the map area. Exhibit 3 also contains a map of Kentucky showing the location of each generating station and schematics showing the location at each generating station where the proposed pollution control equipment will be constructed. 807 KAR 5:001 Section 9(3)(d).

15. Big Rivers expects to finance the proposed construction projects and to file an application with the Commission for approval of the financing. The manner in which Big Rivers

will finance the construction projects is described in Mr. Hite's testimony. 807 KAR 5:001 Section 9(3)(e).

16. An estimated capital cost and an estimated cost of operation for each of the construction projects are listed in the 2012 Plan and are further described in Mr. Berry's testimony. 807 KAR 5:001 Section 9(3)(f).

17. Big Rivers believes each of the construction projects listed in the 2012 Plan, except for the facilities that will be installed at Henderson's Station Two, require a CPCN before Big Rivers can begin construction under KRS 278.020(1), and Big Rivers requests a CPCN for each of those projects. With regard to the Station Two projects, the Commission held in PSC Case No. 93-065 that since Station Two is wholly owned by Henderson, pollution control facilities installed at Station Two do not require Commission approval.[1] As such, Big Rivers also requests a finding from the Commission that the facilities that Big Rivers proposes to install at Station Two do not require a CPCN. Alternatively, if the Commission finds that those projects do require a CPCN, Big Rivers requests a CPCN for those projects, as well.

Authority to Establish a Regulatory Account

18. As explained further in Mr. Hite's testimony, Big Rivers has incurred costs in developing this Application, and it will incur additional costs to prosecute this case. These costs primarily stem from the retention of experts in the legal, regulatory, and engineering professions. In particular, the costs include Big Rivers' attorney and consultant fees, along with the fees of the engineering consultant that was retained to evaluate the compliance options available to Big Rivers. These costs are significant relative to the level of outside services costs built into Big Rivers' base rates. However, they are necessary and prudent, and Big Rivers should have the

[1] *See* Order dated July 19, 1993, in *In the Matter of: City of Henderson, Kentucky, City of Henderson Utility Commission, and Big Rivers Electric Corporation Application for Certificate of Public Convenience and Necessity and to File Plan for Compliance with Clean Air Act and Impose Environmental Surcharge*, PSC Case No. 93-065.

opportunity to recover them. As such, Big Rivers requests that the Commission grant Big Rivers the authority to establish a regulatory account for its actual costs (and accruals for estimated amounts until actual costs can be determined) associated with this case, to amortize those costs over three years, and to recover those costs through the environmental surcharge tariff.

19. Big Rivers' estimate of its costs for prosecuting this case and the specific accounts Big Rivers is seeking to establish are set forth in Mr. Hite's testimony.

20. If the Commission does not authorize the recovery of all of these costs through the environmental surcharge, Big Rivers alternatively requests that the Commission grant Big Rivers the authority to establish a regulatory asset to defer for recovery in Big Rivers' next base rate case the costs associated with this case through the date upon which the Commission issues a final order that are not recoverable through environmental surcharge tariff.

WHEREFORE, Big Rivers requests that, by November 5, 2012, the Commission:

1. approve Big Rivers' 2012 Plan and its proposed changes to its environmental surcharge tariff, billing forms, and monthly reporting forms;
2. grant Big Rivers a CPCN for each of the projects listed in the 2012 Plan (except for the Station Two projects);
3. issue an order finding that the Station Two projects do not require a CPCN or alternatively, grant a CPCN for the Station Two projects;
4. grant Big Rivers the authority to establish a regulatory account for the deferral of its costs of preparing and prosecuting this case;
5. grant Big Rivers the authority to recover such deferred costs through its environmental surcharge tariff; and
6. grant Big Rivers all other relief to which it may appear entitled.

On this the 2nd day of April, 2012.

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

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

SULLIVAN, MOUNTJOY, STAINBACK & MILLER PSC
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R. Michael Sullivan
Bryan R. Reynolds
Tyson A. Kamuf
Mark W. Starnes
C. Ellsworth Mountjoy
Mary L. Moorhouse

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FEB 28 2012
PUBLIC SERVICE COMMISSION

February 27, 2012

Via Federal Express

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

Re: Big Rivers Electric Corporation – Notice of Intent

Dear Mr. DeRouen:

Big Rivers Electric Corporation ("*Big Rivers*") hereby notifies the Kentucky Public Service Commission that Big Rivers intends to file on or after April 2, 2012, an application seeking approval of its 2012 plan to comply with certain environmental requirements (the "*2012 Plan*"), revisions to its environmental surcharge tariff to include the costs associated with the 2012 Plan, and certificates of public convenience and necessity for the pollution control capital construction projects included in the 2012 Plan.

A copy of this notice has been served on the persons shown on the attached service list. Please contact me if you have any questions

Sincerely yours,

James M. Miller

James M. Miller

Enclosure
cc: Mark Bailey
Albert Yockey
Robert Berry

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

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

Service List

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President and CEO
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Owensboro, Kentucky 42302-1389

G. Kelly Nuckols
President and CEO
Jackson Purchase Energy
Corporation
2900 Irvin Cobb Drive
P.O. Box 4030
Paducah, KY 42002-4030

Burns E. Mercer
President/CEO
Meade County R.E.C.C.
1351 Highway 79
P.O. Box 489
Brandenburg, KY 40108-0489

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Application of Big Rivers Electric Corporation for Approval of its 2012 Environmental Compliance Plan, for Approval of its Amended Environmental Cost Recovery Surcharge Tariff, for Certificates of Public Convenience and Necessity, and for Authority to Establish a Regulatory Account	)	Case No. 2012-00063

CERTIFICATE OF NOTICE TO THE PUBLIC

To the Public Service Commission, Frankfort, Ky.

Pursuant to the Rules Governing Tariffs (effective August 4, 1984), I hereby certify that I, Mark A. Bailey, am President and Chief Executive Officer of Big Rivers Electric Corporation (the "Company"), a utility furnishing wholesale electric service within the Commonwealth of Kentucky, which on the 2nd day of April, 2012, issued Tariff P.S.C. No. 24, First Revised Sheet Numbers 3, 8, 33, 46, and 47, cancelling Tariff P.S.C. No. 24, Original Sheet Numbers 3, 8, 33, 46, and 47, to become effective May 2, 2012, and that notice to the public of the issuing of the same is being given in all respects as required by Section 8 of 807 KAR 5:011, as follows:

On the 2nd day of April, 2012, the revised tariff sheets were exhibited for public inspection at the office and place of business of the Company in the territory affected thereby, to wit, at 201 Third Street, Henderson, Kentucky 42420, and that the same will be kept open to public inspection at said office and place of business in conformity with the requirements of Section 8 of 807 KAR 5:011.

On the 2nd day of April, 2012, typewritten notice of the proposed rates or administrative regulations was mailed to each of the three customers of the Company whose rates or charges will be affected thereby, a copy of said notice being attached thereto.

Given under my hand this 2nd day of April, 2012.

Mark A. Bailey

Mark A. Bailey
President and Chief Executive Officer
Big Rivers Electric Corporation
201 Third Street
Henderson, Kentucky 42420

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN to before me by Mark A. Bailey, President and Chief Executive Officer of Big Rivers Electric Corporation, on this the 2nd day of April, 2012.

Paula Mitchell
Notary Public, Ky., State at Large
My commission expires: 1-12-13

Big Rivers
ELECTRIC CORPORATION

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

April 2, 2012

Mr. Sanford Novick
President and CEO
Kenergy Corp.
P. O. Box 1389
Owensboro, KY 42302-1389

Mr. Kelly Nuckols
President and CEO
Jackson Purchase Energy Corp.
P. O. Box 4030
Paducah, KY 42002-4030

Mr. Burns Mercer
President and CEO
Meade County RECC
P. O. Box 489
Brandenburg, KY 40108

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

Gentlemen:

Big Rivers Electric Corporation ("Big Rivers") hereby provides notice that, on this date, it has filed with the Kentucky Public Service Commission in the above-referenced matter an application for approval of its plan to construct new pollution control facilities to comply with the federal Clean Air Act as amended (the "CAAA") and new or pending regulations under the CAAA. That environmental compliance plan (the "2012 Plan") is in additional to Big Rivers' existing environmental compliance plan (the "Existing Plan").

Big Rivers' application to the Public Service Commission also includes (i) a request for approval of revisions to Big Rivers' environmental surcharge tariff to allow Big Rivers to recover the capital and operating costs associated with the 2012 Plan, (ii) a request that the Public Service Commission grant Big Rivers certificates of public convenience and necessity for the pollution control facilities included in the 2012 Plan, and (iii) a request that the Public Service Commission grant Big Rivers authority to establish a regulatory asset for its costs associated with the case and to recover such costs through its environmental surcharge tariff.

A copy of the application, which includes the 2012 Plan and the revised environmental surcharge tariff, is enclosed. The application also includes proposed revised tariff billing forms. The estimated increase per customer class resulting from the proposed revisions to Big Rivers' environmental surcharge tariff is shown on the enclosed schedule.

The rates contained in this notice are the rates proposed by Big Rivers. However, the Public Service Commission may order rates to be charged that differ from these proposed rates. Such action may result in rates for consumers other than the rates in this notice. Any corporation, association, body politic or person may by motion within thirty (30) days after the mailing of this notice request leave to intervene in the proceeding before the Public Service Commission. The motion shall be submitted to the Public Service Commission, 211 Sower Boulevard, P.O. Box 615, Frankfort, Kentucky 40602, and shall set forth the grounds for the request including the status and interest of the party requesting intervention. Intervenors may obtain copies of the application and testimony filed by Big Rivers by contacting Big Rivers Electric Corporation, P.O. Box 24, 201 Third Street, Henderson, Kentucky, 42419. A copy of the application and testimony are available for public inspection at Big Rivers' office at the foregoing street address.

Sincerely yours,

Mark A. Bailey

Mark A. Bailey
President and CEO
Big Rivers Electric Corporation

Enclosures
c: Chris Hopgood, Esq.
Melissa Yates, Esq.
Thomas Brite, Esq.

Big Rivers Electric Corporation
2012 Environmental Compliance Plan
Estimated Billing Impact

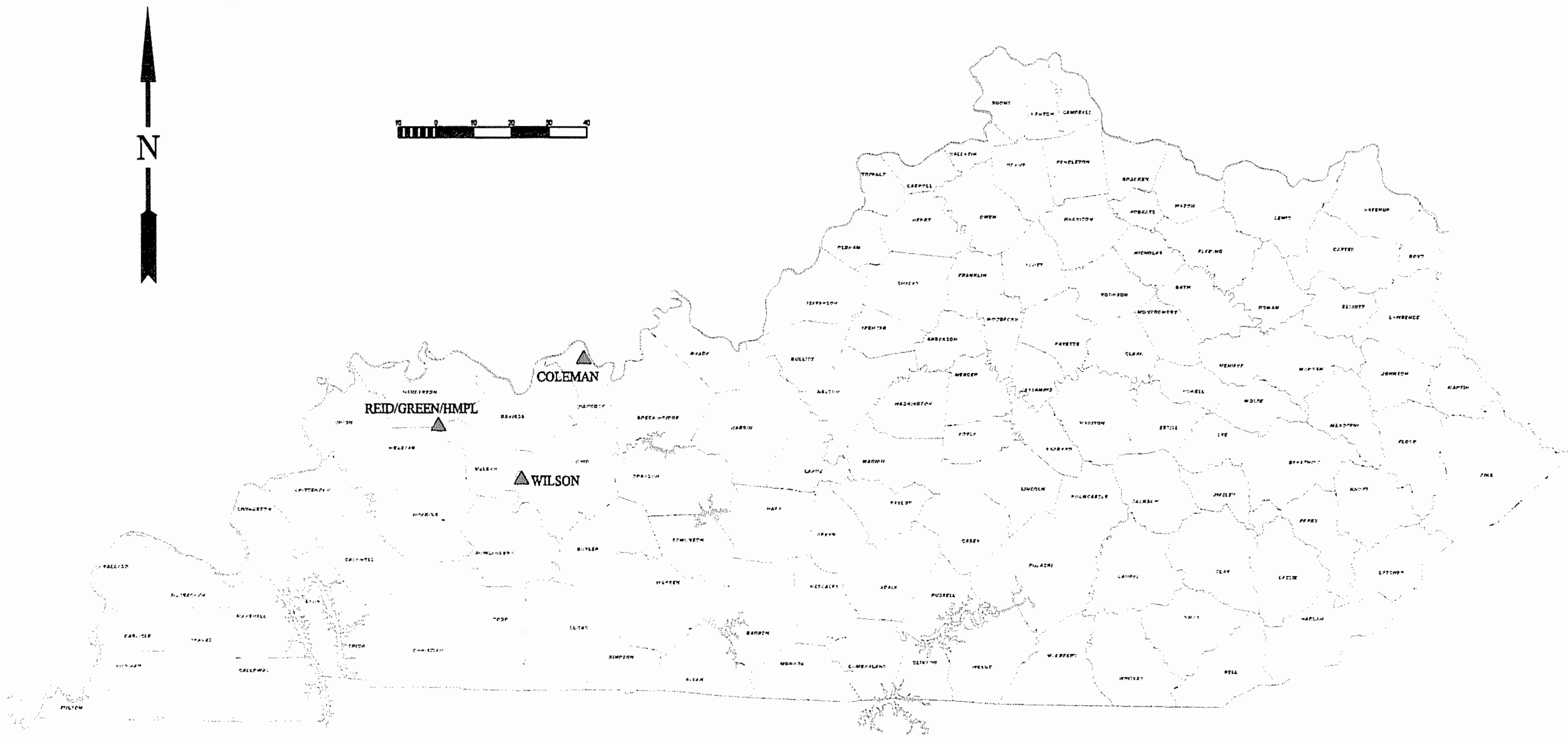
		Rate ($/MWH)			Increase (%)	
		Base 2012	Base 2016	Build 2016	Relative to 2016	Relative to 2012
Line	Class	1	2	3	(3-2) / 2	(3-2) / 1
1	**Gross of MRSM and RER Rider**					
2						
3	Rural	52.64	58.89	62.98	6.9%	7.8%
4	Large Industrial	45.46	51.64	54.80	6.1%	6.9%
5	Smelter Unadjusted	51.08	54.45	58.18	6.8%	7.3%
6	Smelter Adjusted*	48.13	53.09	55.72	5.0%	5.5%
7						
8	**Net of MRSM and RER Rider: Bill Impact**					
9						
10	Rural	44.32	51.27	51.27	0.0%	0.0%
11	Large Industrial	37.21	51.64	54.80	6.1%	8.5%
12	Smelter Unadjusted	51.08	54.45	58.18	6.8%	7.3%
13	Smelter Adjusted*	48.13	53.09	55.72	5.0%	5.5%

*Smelter Adjusted reflects removal of the TIER Adjustment Charge. The Build Case has lower off-system net sales margin in 2016 due to 2012 Plan costs, causing the Smelters to move up within the TIER bandwidth.

The MRSM and the RER Rider mitigate the costs of ES and FAC to Rurals from Economic Reserve and Rural Economic Reserve in 2016 and beyond.

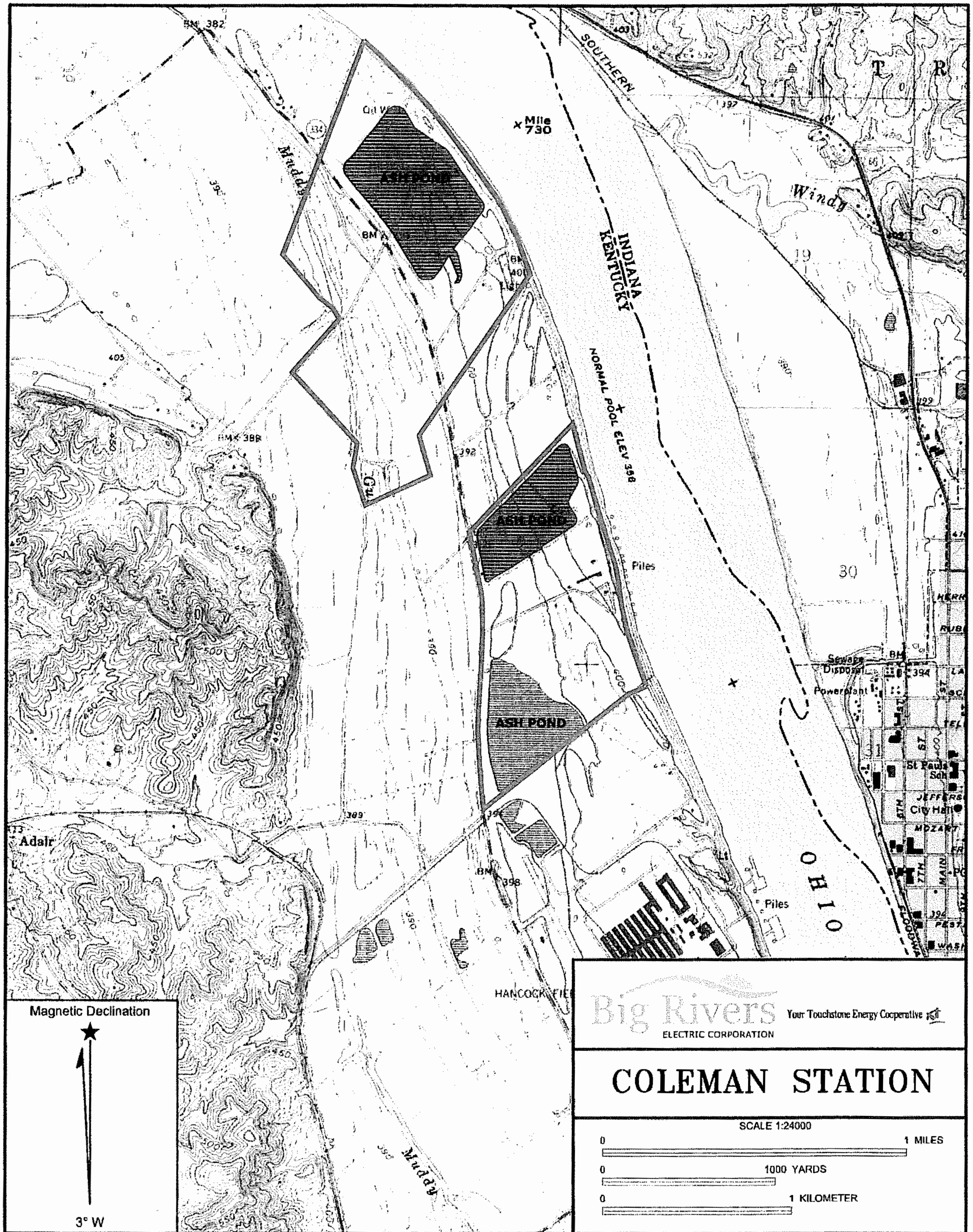
Case No. 2012-00063
Exhibit 2
Page 5 of 5

COMMONWEALTH OF KENTUCKY



Big Rivers ELECTRIC CORPORATION
Your Touchstone Energy Cooperative

KENTUCKY MAP
SHOWING PLANT LOCATION



Big Rivers ELECTRIC CORPORATION Your Touchstone Energy Cooperative

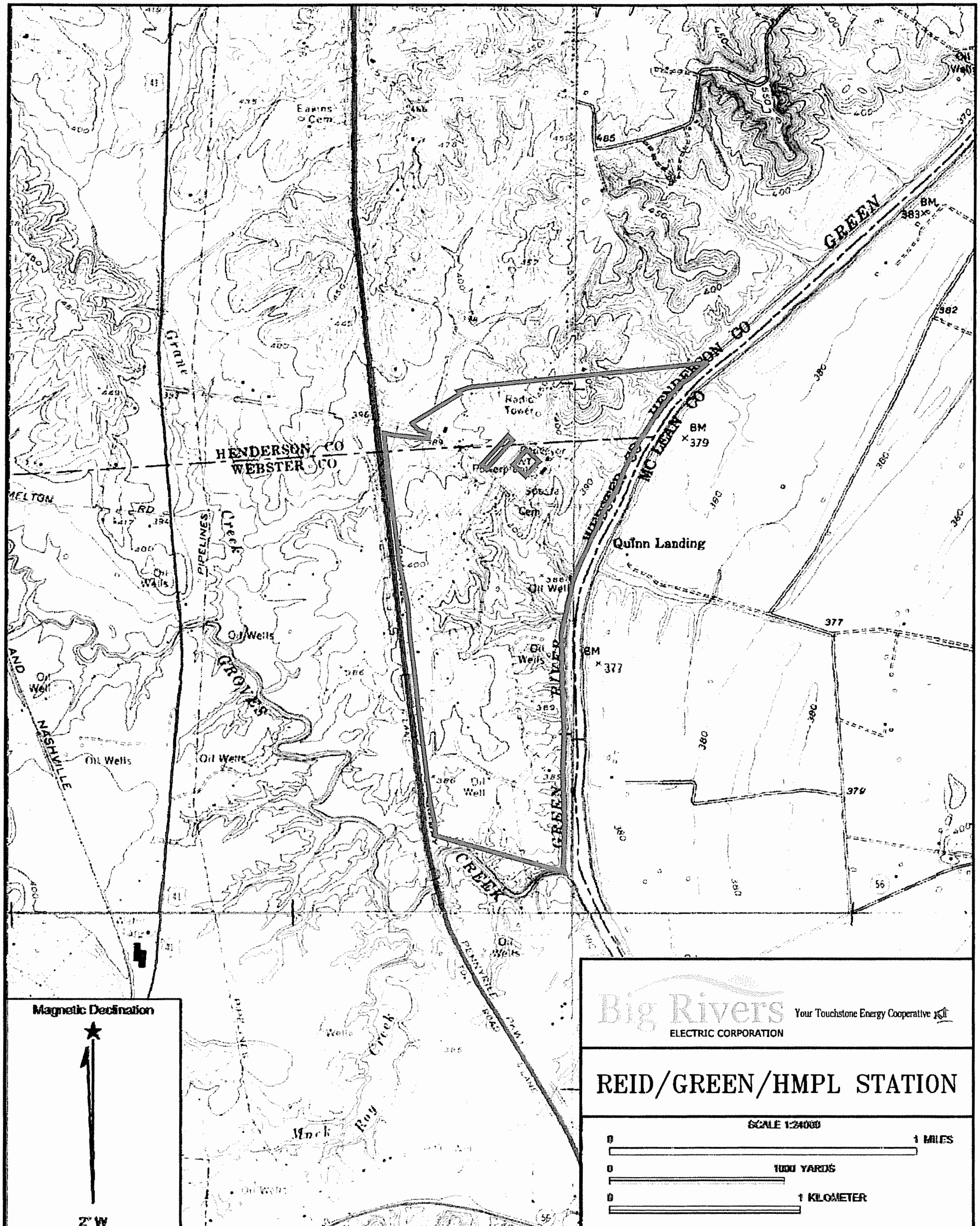
COLEMAN STATION

SCALE 1:24000

0 1 MILES

0 1000 YARDS

0 1 KILOMETER



Big Rivers ELECTRIC CORPORATION Your Touchstone Energy Cooperative

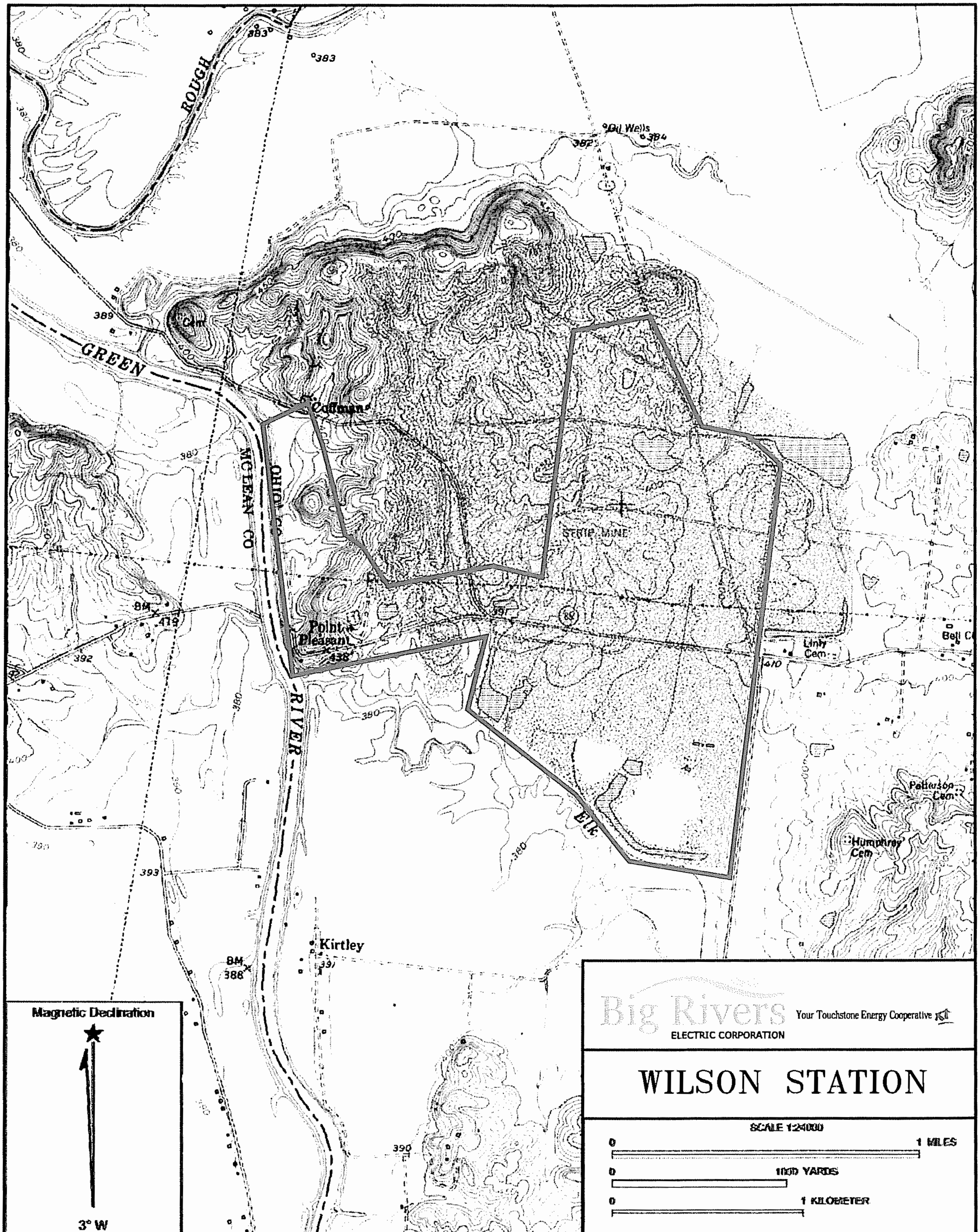
REID/GREEN/HMPL STATION

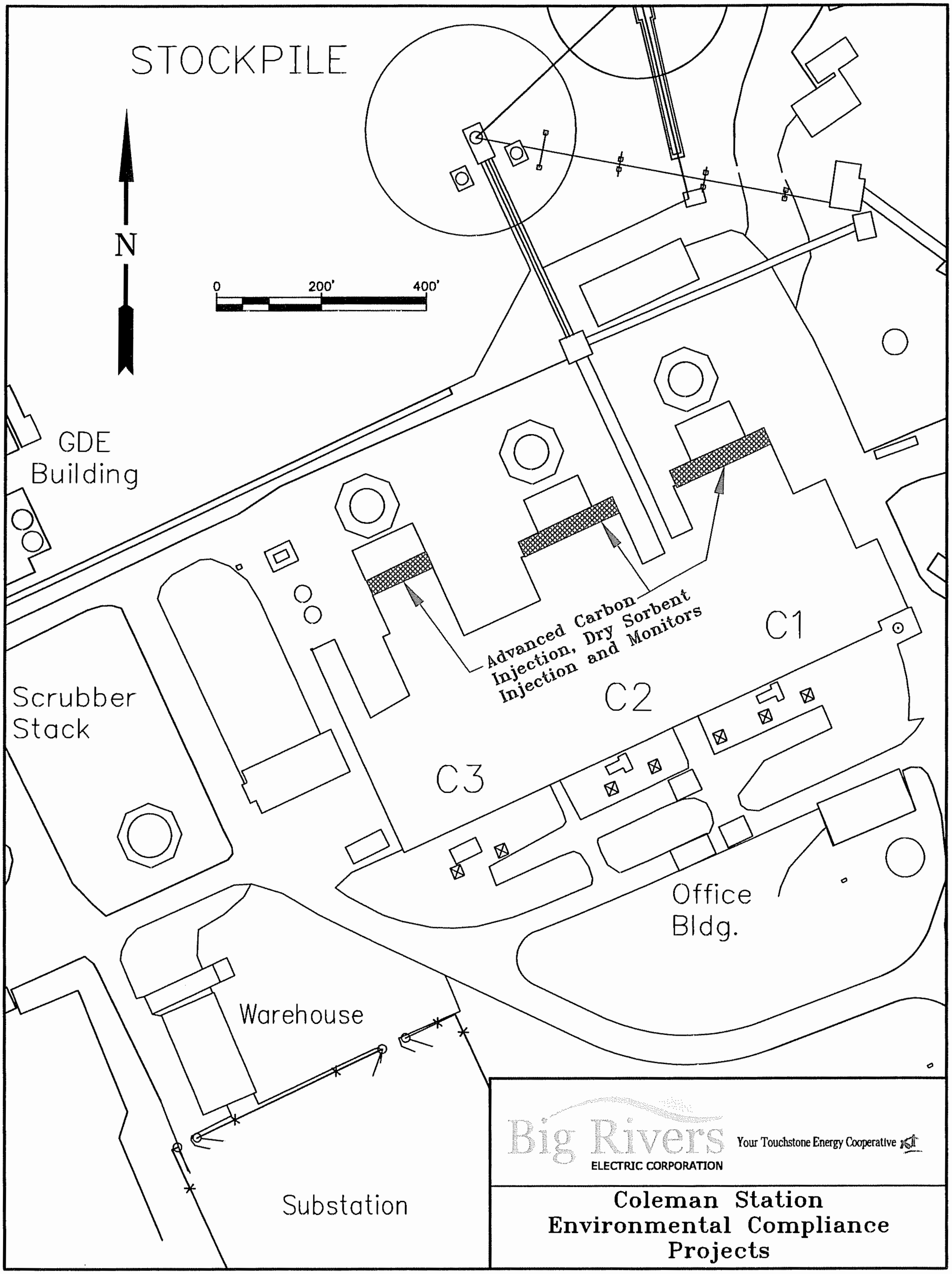
SCALE 1:24000

0 1 MILES

0 1000 YARDS

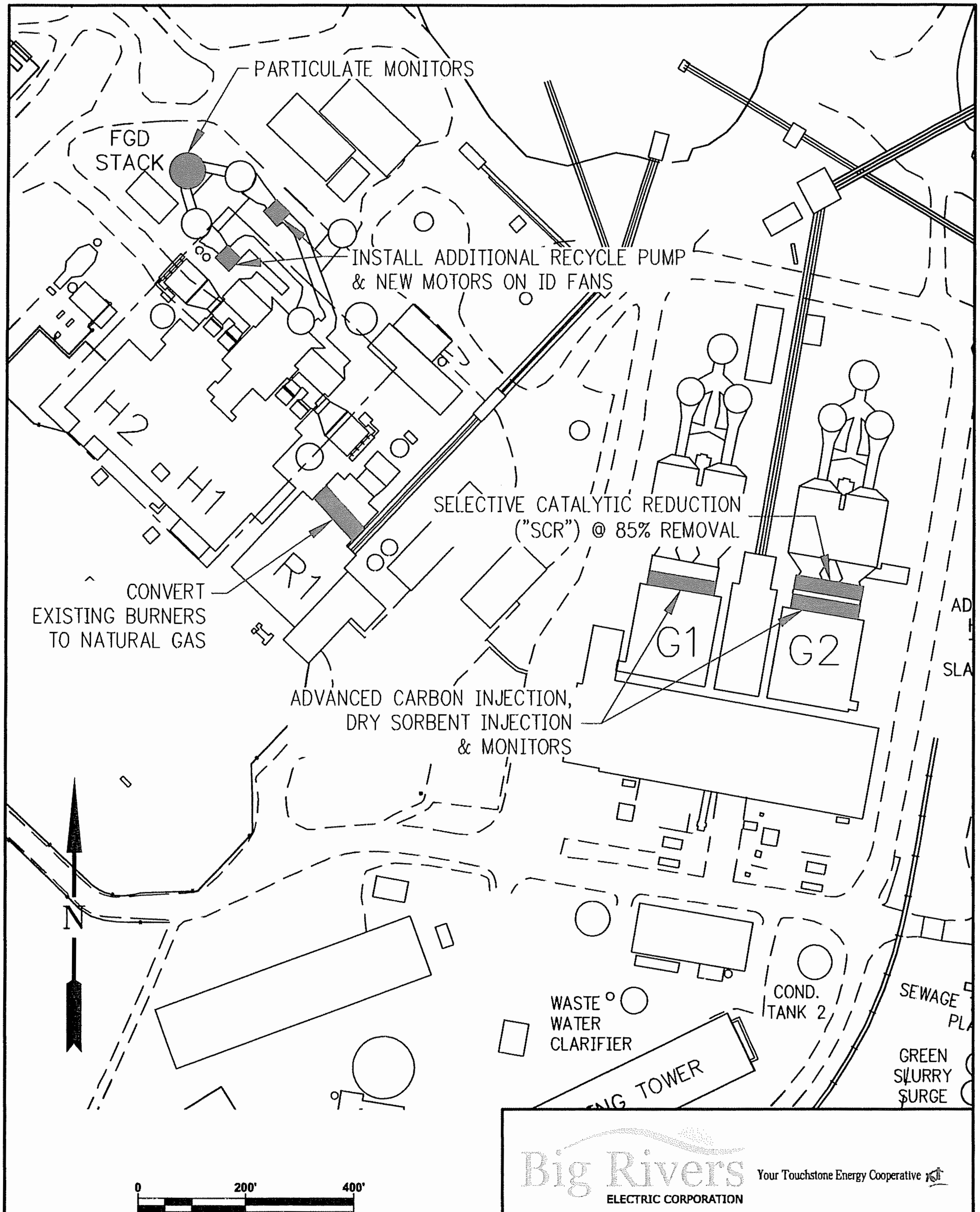
0 1 KILOMETER


ROUGH
GREEN
RIVER
OHIO CO
MCLEAN CO
Oil Wells
Coffman
Point Pleasant
Cem
STRIP MINE
Linn Cem
Bell C
Patterson Cem
Humphrey Cem
Elk
Kirtley
BM 388
BM 419
383
384
382
389
380
392
393
397
410
438
390
Magnetic Declination
3° W
Big Rivers ELECTRIC CORPORATION
Your Touchstone Energy Cooperative
WILSON STATION
SCALE 1:24000
0
1 MILES
1000 YARDS
1 KILOMETER



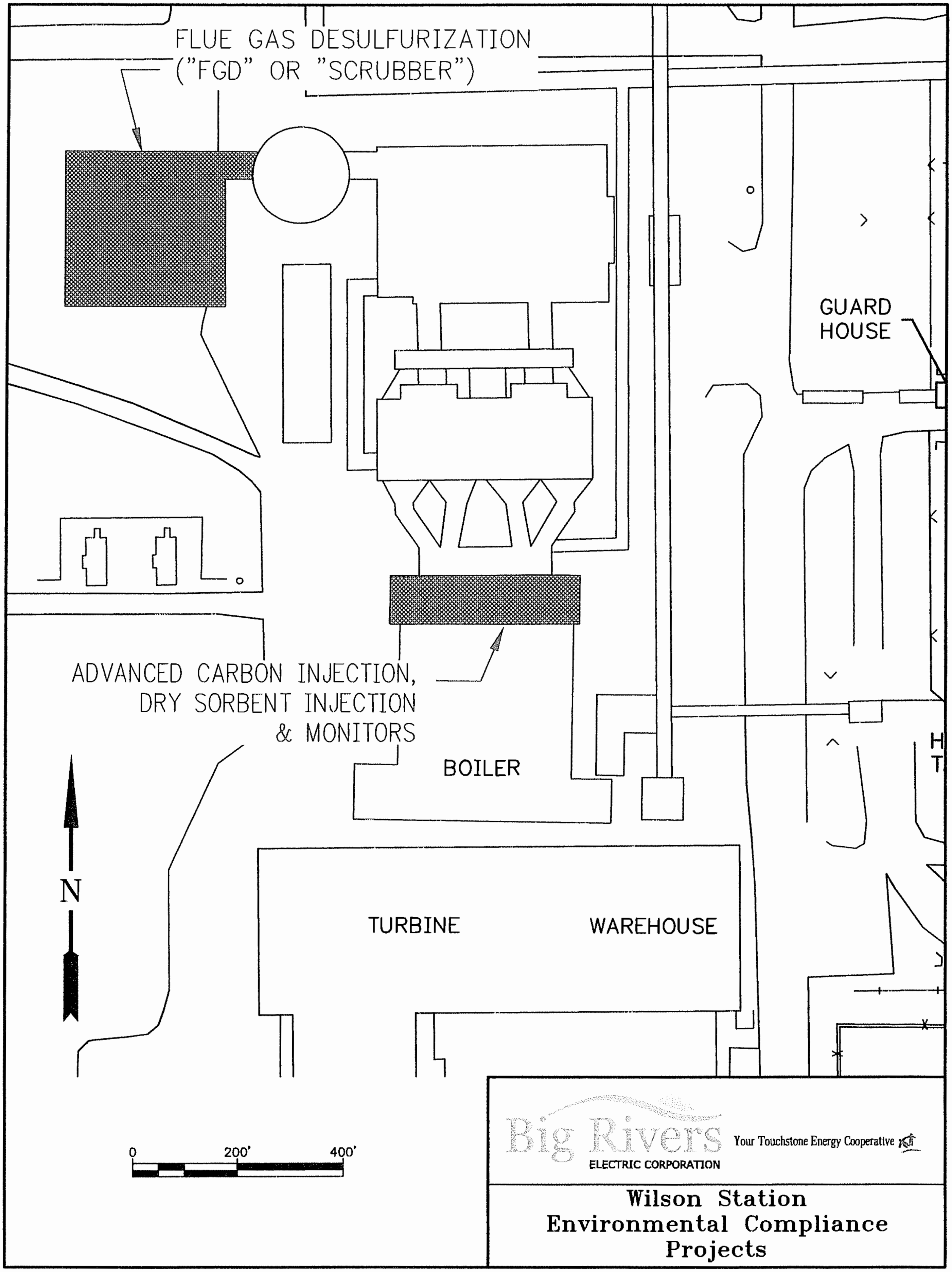
Big Rivers ELECTRIC CORPORATION Your Touchstone Energy Cooperative

Coleman Station Environmental Compliance Projects



Reid/Green/HMPL Station
Environmental Compliance
Projects

Case No. 2012-00063
Exhibit 3
Page 6 of 7



Wilson Station Environmental Compliance Projects

Case No. 2012-00063
Exhibit 3
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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

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

DIRECT TESTIMONY

OF

ROBERT W. BERRY
VICE PRESIDENT, PRODUCTION

ON BEHALF OF

BIG RIVERS ELECTRIC CORPORATION

FILED: April 2, 2012

DIRECT TESTIMONY
OF
ROBERT W. BERRY

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DIRECT TESTIMONY
OF
ROBERT W. BERRY

I. INTRODUCTION

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

A. My name is Robert W. Berry. I am employed by Big Rivers Electric Corporation ("Big Rivers"), 201 Third Street, Henderson Kentucky, 42420 as its Vice President of Production.

Q. Please describe your job responsibilities.

A. Big Rivers operates ten generating units at three locations in Western Kentucky. In my capacity as Vice President of Production, I am responsible for the safe and strategic operation and maintenance activities associated with Big Rivers' generating assets, as well as Energy Services, which includes Resource Planning and Forecasting, Power Portfolio Optimization and Fuel Procurement.

Q. Briefly describe your education and work experience.

A. I hold an Associate degree in Mechanical Engineering Technology from the University of Kentucky Community College system and a Bachelor of Science in Business Management from Mid-Continent University. I have held the position of Vice President of Production since July 2009 upon the closing of the transaction that unwound Big Rivers' 1998 lease with E.ON U.S., LLC and its affiliates (the "Unwind Transaction"), described in Case

No. 2007-00455. Prior to the closing of the Unwind Transaction, I was employed by Western Kentucky Energy Corporation ("WKE") for 11 years beginning as a Maintenance Manager in 1998. I held the position of Plant Manager of the Coleman Generating Station from 2000 until 2003, at which time I became the Plant Manager of the Sebree Generating Station. Altogether, I have over 31 years of experience in this system, having worked for both Big Rivers and WKE. A summary of my work experience is provided in Exhibit Berry-1.

Q. Have you previously testified before the Kentucky Public Service Commission ("Commission")?

A. Yes, I testified on behalf of Big Rivers in the Unwind Transaction proceeding, Case No. 2007-00455, and in Big Rivers' recent rate case, Case No. 2011-00036.

II. <u>PURPOSE OF TESTIMONY</u>

Q. What is the purpose of your testimony?

A. My testimony provides an overview of the request of Big Rivers in this proceeding and summarizes the other witnesses' testimony supporting Big Rivers' application. First, I provide an overview of Big Rivers' 2012 environmental compliance plan ("2012 Plan"). I summarize the request for certificates of public convenience and necessity ("CPCNs") for facilities contained in the 2012 Plan. I explain why Big Rivers is seeking environmental surcharge recovery of its 2012 Plan through the environmental surcharge ("ES") tariff rider. I discuss Big Rivers' communications with its stakeholders regarding the 2012 Plan and the proposed ES tariff rider. I discuss Big Rivers' consideration of the two large aluminum smelters, Century Aluminum of Kentucky General Partnership ("Century") and Alcan Primary Products Corporation ("Alcan") (collectively, the "Smelters") with which Big Rivers has special contracts (the "Smelter Agreements"). Finally, I provide technical support for Big Rivers' 2012 Plan, which identifies the proposed pollution control equipment additions that will be required for compliance with the new rules recently promulgated by the United States Environmental Protection Agency ("EPA"), specifically the Cross-State Air Pollution Rule ("CSAPR") and the Mercury and Air Toxics Standards ("MATS") rule.

Q. Are you sponsoring any exhibits?

A. Yes. I have prepared the following exhibits to my prepared testimony:

Exhibit Berry-1 – Robert W. Berry Professional Summary

Exhibit Berry-2 – Big Rivers 2012 Environmental Compliance Plan

Exhibit Berry-3 – Plant Information Provided to Sargent & Lundy – Tables 1-2 through 1-4

Exhibit Berry-4 – Screened technologies considered in the Sargent & Lundy Study – Table 5-1

Exhibit Berry-5 – Options to Comply with CSAPR and NAAQS – Tables 6-1 through 6-3

Exhibit Berry-6 – MACT TPM Compliance Summary – Table 6-5

III. <u>INTRODUCTION & OVERVIEW</u>

Q. Please provide an overview of the request of Big Rivers in this proceeding.

A. In this proceeding, Big Rivers is requesting that the Commission (i) approve Big Rivers' 2012 Plan and its proposed changes to its ES tariff, certain tariff billing forms, and monthly reporting forms; (ii) grant Big Rivers a CPCN for each of the projects listed in the 2012 Plan (except for the Station Two projects); and (iii) grant Big Rivers the authority to establish a regulatory asset for the costs associated with this case and authorize the recovery of such costs through the ES tariff. Big Rivers is not seeking a certificate of public convenience and necessity for the Henderson Municipal Power & Light ("HMP&L") Station Two projects because the statutes and prior Commission rulings do not require it for additions to the municipally-owned facility.

Q. Please identify the witnesses who will testify for Big Rivers and the areas their testimony will address.

A. In addition to my testimony, Big Rivers presents the testimony of the following witnesses:

- **William DePriest** (Exhibit 5). Mr. DePriest, President and Director of DePriest Consulting and former executive at the firm of Sargent & Lundy, LLC ("S&L"), sponsors the S&L Environmental Compliance Study, prepared at the request of Big Rivers. S&L is an engineering and consulting firm specializing in professional services for the electric power industry. Big Rivers retained S&L to perform a focused compliance study addressing the recently-issued, proposed and pending environmental regulations and legislation and alternative technology strategies for achieving compliance with the applicable initiatives at Big Rivers' generating stations and at Station Two.

- **Thomas L. Shaw** (Exhibit 6). Mr. Shaw, Big Rivers' Director of Environmental Services, identifies the environmental regulatory requirements that cause the need for the pollution control facilities in the 2012 Plan and demonstrates how the projects identified in the 2012 Plan are necessary for Big Rivers' compliance with the requirements of the Clean Air Act as amended ("CAAA"), CSAPR, and the proposed MATS rule.

- **Mark A. Hite** (Exhibit 7). Mr. Hite, Big Rivers' Vice President of Accounting and Interim Chief Financial Officer, describes Big Rivers' evaluation of the cost effectiveness of the alternatives considered for inclusion in the 2012 Plan, including the methodology, major assumptions, sensitivity analyses, and results. Mr. Hite also describes the accounting associated with the projects in the 2012 Plan and affirms that the costs for which Big Rivers is seeking recovery through its proposed ES tariff rider amendments are not included in base rates. He describes how Big Rivers plans to finance the construction of the projects included in the 2012 Plan and explains the request to establish a regulatory asset for the costs associated with this proceeding.

- **John Wolfram** (Exhibit 8). Mr. Wolfram, Senior Consultant with The Prime Group, LLC, describes the mechanics and components of the proposed ES tariff rider amendments and explains how the surcharge will be calculated and charged to Big Rivers' members. Mr. Wolfram sponsors the revised ES tariff rider, identifies the specific cost components of environmental compliance to be included in the ES, defines Big Rivers' reporting procedures and monthly reports for the ES, and provides an estimate of the rate impact of the costs incurred in connection with the new pollution control projects in Big Rivers' 2012 Plan.

Q. Please describe the elements of the 2012 Plan that Big Rivers proposes in this proceeding.

A. Big Rivers' 2012 Plan includes (1) installing a new scrubber on Big Rivers' Wilson Unit to increase sulfur dioxide ("SO_2") removal efficiency from 91% to 99%, (2) installing a selective catalytic reduction ("SCR") module on Big Rivers' Green Unit 2 to increase nitrous oxides ("NO_X") removal efficiency from 50% to 85%, (3) modifying the scrubbers on HMP&L Station Two Units 1 and 2 to improve SO_2 removal from 93.5% to 97%, and (4) converting the existing equipment at Big Rivers' Reid Unit 1 to burn natural gas instead of coal, as necessary, to comply with the CSAPR rule. To comply with the new MATS regulation, Big Rivers must install activated carbon injection equipment for mercury ("Hg") removal, dry sorbent injection equipment for acid gas removal, and continuous emission compliance monitors on all three of Big Rivers' Coleman Units, the two Green Units and the Wilson Unit; and even though testing has proven the two HMP&L Units are low mercury emitters, continuous emission monitors must be installed to demonstrate constant compliance. As for Reid Unit 1 and the Reid Combustion Turbine, natural gas fired units are not subject to the MATS regulation.

Q. What are the environmental requirements that give rise to the projects in the 2012 Plan?

A. CSAPR and the MATS rule are driving the vast majority of what Big Rivers proposes in its 2012 Plan. CSAPR is the successor to the Clean Air Interstate Rule ("CAIR") that imposes tighter restrictions on SO_2 and NO_x to reduce 2.5-micron particulate matter ("$PM_{2.5}$") emissions. The proposed MATS rule is the successor to the Clean Air Mercury Rule ("CAMR") that imposes significant new and tightened emissions restrictions for mercury, particulate matter (a surrogate for hazardous non-mercury metals), and hydrogen chloride ("HCl") a surrogate for hazardous acid gases). These rules are described in detail in the direct testimony of Mr. Shaw.

Q. Please describe the emission reductions that the Big Rivers system must achieve in order to comply with CSAPR.

A. While Big Rivers will have minimal SO_2 reductions for Phase 1 of CSAPR, reductions of approximately 50% will be required when Phase 2 becomes effective. Regarding NOx emissions, Big Rivers projects that it will be required to reduce emissions by 7% for Phase 1 and by 16% total for Phase 2. Phase 2 is expected to take effect in year 3 after CSAPR is finalized.

Q. Please describe the impacts of MATS on the Big Rivers system.

A. While Big Rivers can meet CSAPR requirements on a system-wide basis, MATS requires unit specific reductions. Testing indicates that all units (except Station Two) will require mercury reductions. All units are currently under the filterable particulate limits listed in the final MATS rule. The majority of the Big Rivers units will meet HCl restrictions by achieving a SO_2 emission limit beneath the 0.2 #/MMBTU limit. For units that do not meet this limit, testing indicates that HCl emissions will be beneath the limits set in the MATS rule.

Q. How did Big Rivers determine which projects should comprise the 2012 Plan?

A. Big Rivers retained S&L, an engineering and consulting firm specializing in professional services for the electric power industry, to perform a focused compliance study addressing recently-issued, proposed and pending environmental regulations and legislation, and the potential impacts these initiatives may have on operations at Big Rivers' generating stations. S&L recommended a suite of technologies that would allow Big Rivers to comply with the CSAPR and MATS requirements. This is described in detail in the direct testimony of Mr. DePriest. Big Rivers then prepared an evaluation of the option of constructing those technologies against other options, including purchasing power in the wholesale market. Big Rivers determined that the proposed 2012 Plan is the most cost effective means for Big Rivers to achieve compliance with CSAPR and MATS. This evaluation is described in the direct testimony of Mr. Hite.

Q. How does Big Rivers propose to recover the costs of the projects in the 2012 Plan?

A. Big Rivers proposes to recover the costs of the 2012 Plan through its ES tariff rider. The proposed tariff revisions are described in the direct testimony of Mr. Wolfram.

Q. Are any of the projects in the 2012 Plan already included in Big Rivers' existing environmental compliance plan?

A. No.

Q. Are any costs associated with the projects in the 2012 Plan already being recovered by Big Rivers through its approved ES tariff or through its base rates?

A. No.

Q. Is Big Rivers proposing any changes to its approved ES tariff?

A. Yes. Big Rivers' existing environmental compliance plan includes no capital projects. As such, Big Rivers' current ES tariff only allows Big Rivers to recover operation and maintenance ("O&M") costs, and those costs are allocated on a per kilowatt hour ("kWh") basis. Big Rivers is proposing two noteworthy changes to the calculation of the environmental surcharge factor specified in the ES tariff rider. The first is a change to the determination of total eligible environmental compliance plan costs: Big Rivers proposes to add a component to recover the fixed costs of the projects in the 2012 Plan (including a return on investment). The second is a change to the cost allocation method used in the formula: Big Rivers proposes to revise the existing "per-kWh" allocation of costs to a "percentage of Total Adjusted Revenue" allocation of costs. Both changes are proposed in order to accommodate the addition of capital projects in the 2012 Plan. These changes are discussed in detail in the direct testimony of Mr. Wolfram.

Q. How does Big Rivers propose to allocate the costs of the projects in the 2012 Plan to its members via the ES tariff?

A. Big Rivers proposes to allocate the costs of the 2012 Plan on the basis of total revenues, adjusted for certain revenue items specified in the contracts between Big Rivers and Kenergy Corp. ("Kenergy") relating to electric service that Kenergy provides to the Smelters and certain other revenues and credits. This is described in detail in the direct testimony of Mr. Wolfram.

Q. What is the effect on rates of the proposed 2012 Plan and associated cost recovery?

A. In 2016, when the projects in the 2012 Plan should be complete, total billings to the rate classes will increase by approximately 6.9% relative to projected 2016 billings absent the 2012 Plan, and by approximately 7.8% relative to projected 2012 billings. However, because of the Member Rate Stability Mechanism ("MRSM") and the Rural Economic Reserve ("RER") tariff rider that are currently in place, the members taking service under

Rate Schedule RDS will have *no* immediate impact on their bills, because the MRSM and the RER tariff rider entirely mitigate the bill impact of the 2012 Plan until the Economic Reserve and RER accounts are depleted. This is discussed in the direct testimony of Mr. Wolfram.

Q. Did Big Rivers communicate with its members, constituents, or other stakeholders during the planning and development of the 2012 plan or this application?

A. Yes. Big Rivers has been researching and discussing the implications of pending new environmental requirements with its constituents for some time. Big Rivers presented information about the proposed 2012 Plan to its Board of Directors on January 20, February 21, and March 16, 2012; to its Coordinating Committee, which consists of representatives of Big Rivers and the Smelters, on February 16, 2012; and to HMP&L on February 15, 2012. Additionally, while Big Rivers' members were already familiar with Big Rivers' plans, Big Rivers provided formal notice to its members on April 2, 2012. Finally, Big Rivers has provided notice to the Rural Utilities Service ("RUS") of its intent to initiate the process of obtaining various RUS approvals or consents that may be required for implementation of the 2012 Plan.

Q. Does the Big Rivers 2012 Plan consider the potential for loss of one or both Smelters during the study period contemplated in this application?

A. Yes. As Mr. Hite describes in his direct testimony, Big Rivers analyzed the economic impact of two compliance options with regard to a loss in Smelter load starting January 1, 2014. The compliance options were (i) the projects in the 2012 Plan (the "Build Case"), and (ii) complying with MATS by installing the MATS equipment in the 2012 Plan and complying with CSAPR by reducing generation and purchasing power in the wholesale market (the "Buy Case"). This sensitivity analysis was performed to determine if the least cost option would remain the least cost option if the Smelters were to leave Big Rivers' system. Big Rivers performed this sensitivity because the Smelters have said that increases in electric power rates can adversely affect the viability and longevity of their operations.

Q. Was the end result any different in the Smelter load loss sensitivity evaluation?

A. No. The resulting plan with the Smelter load included is the same as the resulting plan with the Smelter load excluded; the Build Case resulted in a lower member revenue requirement than the Buy Case on a present value basis, with or without the Smelter load on the Big Rivers system.

IV. PROJECT OVERVIEW AND DESCRIPTIONS

Q. Please provide an overview of the projects in Big Rivers' 2012 Plan.

A. All of the Big Rivers coal-fired, owned and operated units except one are already fitted with SO_2, NO_X and particulate emission control equipment. If operating at its projected capacity (above 80% net capacity factor), the Big Rivers fleet will not be capable of meeting the requirements of CSAPR and MATS without significant capital investment in additional emissions reduction equipment. Unless emission removal efficiencies are improved, generation will need to be curtailed by 27% from historic levels in Phase 2 of CSAPR. An investment in pollution control equipment will be more cost effective than reducing generation. In order to meet the proposed CSAPR and MATS regulations it is imperative that Big Rivers invest in the pollution control technologies contained in the 2012 Plan.

Q. Please describe the information provided on the 2012 Plan in Exhibit Berry-2.

A. Exhibit Berry-2 is a high level overview of Big Rivers' environmental compliance plan. On page one of this exhibit, the first column represents the project number that has been assigned for reference in this proceeding. The second column describes the pollutant(s) emission that needs to be further reduced in order to meet the limits imposed by the new regulations. In the third column, Big Rivers lists the type of control facility that has been recommended to reduce emission of the identified pollutant(s). The fourth column describes the Plant and Unit at which the new control facilities are to be installed. The fifth column describes the EPA requirement that will be satisfied. The next two columns describe the environmental permits that will be required and whether a certificate of public convenience and necessity will be required. The final two columns show the projected completion for each project and the estimated capital cost to design and construct the control facilities. On page two of Exhibit Berry-2, the first four columns are identical to page 1, and the remaining columns represent the estimated annual incremental increase in O&M costs for each of the projects for the next twelve years.

Q. How do the projects in the 2012 Plan allow Big Rivers to satisfy the applicable environmental requirements described in this application?

A. Once the projects in this plan are completed, emissions of SO_2, NO_X, Hg, and acid gases from Big Rivers' units will be sufficiently reduced to comply with the CSAPR and MATS regulations. This conclusion is supported by the direct testimony of Mr. Shaw.

A. PROJECT 4: SCRUBBER AT WILSON UNIT 1

Q. Please describe Project Number 4.

A. Although the Wilson Unit currently has a flue gas desulfurization ("FGD" or "Scrubber") system, its SO_2 removal efficiency is only 91%. As a part of Big Rivers' overall CSAPR compliance plan, SO_2 removal efficiency on the Wilson Unit must be improved to 99%. Due to the design and technology of the existing Wilson Scrubber there are no known modifications or engineering solutions to adequately improve its removal efficiency; thus, a new advanced technology Scrubber must be built. Project Number 4 is to install a new FGD system on the Wilson Unit to reduce emission of SO_2. The new FGD system will reduce the Wilson Unit's projected 2016 SO_2 emissions from 8,740 tons to 1,845 tons.

Q. Please describe the proposed construction schedule, capital costs, and O&M costs for this project.

A. Preliminary engineering and design for this project will begin in 2012 with final drawings completed and approved in 2013. Fabrication and construction will begin in 2013 with completion and acceptance scheduled for January 1, 2016. The estimated capital cost for this project is $139 million, and incremental O&M expenses are estimated at approximately $760,000 in 2016.

B. PROJECT 5: SCR AT GREEN UNIT 2

Q. Please describe Project Number 5.

A. Green Unit 2 is currently equipped with a proprietary coal re-burn technology for NO_X control with reduction capability of 50%; however, as part of Big Rivers' overall CSAPR compliance plan, NO_X reduction capability on this unit must be improved to 85% to permit Big Rivers to meet its NOx emission requirements under CSAPR on a system wide basis. Due to the design and technology of the existing coal reburn system, there are no known modifications or engineering solutions to adequately improve reduction capability; thus, a new advanced technology SCR must be built. Project Number 5 is to install a new SCR system on Green Unit 2 to decrease its NO_X emissions. The new SCR equipment will reduce projected 2016 NO_X emissions from the Green Unit 2 from 2,413 tons per year to 336 tons per year.

Q. Please describe the proposed construction schedule, capital costs, and O&M costs for this project.

A. Preliminary engineering and design for this project will begin in 2012 with final drawings completed and approved in mid-2013. Fabrication and construction will begin in 2013 with completion and acceptance scheduled for July 1, 2015. The estimated capital cost for this project is $81 million, and incremental O&M expenses are estimated at approximately $1.6 million in 2015.

C. PROJECT 6: REID UNIT 1 CONVERSION TO NATURAL GAS

Q. Please describe Project Number 6.

A. Reid Unit 1 is the smallest and oldest plant in Big Rivers' fleet and is currently not equipped with SO_2 or NO_X control equipment. In 2004, four of the boiler's eight coal burners were converted to natural gas to meet the CAIR NO_X State Implementation Plan ("SIP") call regulation; however, the gas burners were never permitted, tested, or put into service due to high natural gas pricing in the mid 2000's. The S&L study, further described below, determined that the best way to bring this facility into compliance was to complete the existing conversion project and fire the boiler solely with natural gas. Natural gas firing will reduce SO_2 and NO_X emissions for CSAPR, and exempt it from MATS. This project will provide the maintenance, testing and other necessary tasks to complete the existing natural gas conversion that was started in 2004. Natural gas firing will reduce the unit's projected 2014 SO_2 emissions from 3,162 tons to less than 1 ton and reduce its projected 2014 NO_X emissions from 312 tons to 6 tons.

Q. Please describe the proposed construction schedule, capital costs, and O&M costs for this project.

A. Engineering and design for this project will begin in 2012 with final drawings completed and approved in 2013. Maintenance and testing will begin in 2013 with completion and acceptance scheduled for January 1, 2014. The estimated capital cost for this project is $1.2 million, and ongoing O&M expenses are not expected to increase. However, anticipated increases in fuel cost will most likely cause this unit to continue to be used for peaking service in the future.

D. PROJECT 7: UPGRADES AT HMP&L UNITS 1 & 2

Q. Please describe Project Number 7.

A. Although HMP&L Units 1 and 2 are currently equipped with FGD systems, their SO_2 removal efficiency is only 93.5%. As a part of Big Rivers' overall CSAPR compliance plan, SO_2 removal efficiency on the HMP&L Units must be improved to 97%. The S&L study determined that by installing additional slurry recycle pumps and modifying the booster fans to offset the additional pressure drop across the FGD towers, SO_2 emissions on these units could be reduced sufficiently to comply with CSAPR. This project will reduce the projected 2015 SO_2 emissions from the HMP&L Units from 5,637 tons to 2,054 tons per year.

Q. Please describe the proposed construction schedule, capital costs, and O&M costs for this project.

A. Preliminary engineering and design for this project will begin in 2012 with final drawings completed and approved by mid-2013. Fabrication and construction will begin in 2013 with completion and acceptance scheduled for January 1, 2015. The estimated capital cost for this project is $6.3 million, and incremental O&M expenses are estimated at approximately $820,000 for 2015. These costs include HMP&L's share of those costs. Big Rivers' share of capital costs net of HMP&L is estimated to be $3.85 million, and its share of O&M costs net of HMP&L is estimated to be $475,000.

Q Has HMP&L agreed to these projects for Station Two?

A Big Rivers has submitted the Station Two portion of the 2012 Plan to HMP&L, and the proposal is under review by HMP&L.

E. PROJECTS 8, 9 & 10: ACTIVATED CARBON INJECTION, DRY SORBENT INJECTION & MONITORS AT COLEMAN, WILSON AND GREEN STATIONS

Q. Please describe Project Numbers 8, 9 and 10.

A. Testing of the exhaust gases at the Coleman, Wilson, and Green Stations indicate that these units emit higher levels of mercury than will be allowed under the new MATS rule. In order to reduce the mercury emissions from the exhaust gases at these plants, activated carbon can be injected into the exhaust gas to react with the mercury, and the combined elements can be collected with particulate removal equipment. The presence of acid gases, specifically sulfur trioxide ("SO_3"), inhibits the reaction between mercury and activated carbon, but industry testing has revealed that injecting a dry sorbent such as hydrated lime or trona to capture SO_3 ahead of the activated carbon would restore the reaction between the carbon and mercury. The S&L study determined that dry sorbent injection ahead of the activated carbon into the outlet gases from these units would reduce their mercury emissions sufficiently to comply with MATS. Since the MATS rule also requires companies to provide evidence of compliance, continuous emissions monitors must be installed to sample and analyze the exhaust gases. These monitors are included in Project Numbers 8, 9 and 10.

Q. Please describe the proposed construction schedules, capital costs, and O&M costs for these projects.

A. Preliminary engineering and design for this project will begin in 2013 with final drawings completed and approved by mid-2014. Fabrication and construction will begin in 2014 with completion and acceptance scheduled for January 1, 2016. The estimated capital costs for these three projects are $58.2 million, and O&M expenses are estimated at approximately $10 million in 2016.

F. PROJECT 11: MONITORS AT HMP&L UNITS 1 & 2

Q. Please describe Project Number 11.

A. Although testing has proven the two HMP&L Units are low mercury emitters, continuous emission monitors must be installed to demonstrate constant compliance. Project Number 11 is to install continuous emissions monitors to sample and analyze the exhaust gases.

Q. Please describe the proposed construction schedules, capital costs, and O&M costs for this project.

A. Engineering, design, procurement and installation for Project Number 11 will all be completed in 2015 with completion and acceptance scheduled for January 1, 2016. The estimated capital costs for this project are $480,000, and ongoing O&M expenses are estimated at approximately $40,000 per year. These costs include HMP&L's share of those costs. Big Rivers' share of capital costs net of HMP&L is estimated to be $280,000, and its share of O&M costs net of HMP&L is estimated to be $25,250.

Q. Please describe in detail the parasitic load associated with operating each of the capital additions.

A. The S&L study did not include calculating actual auxiliary power consumption for the recommended compliance strategies. Detailed engineering for each project will have to be completed before actual power consumption can be determined, but Big Rivers believes it will be insignificant. The study did include estimated auxiliary power requirements for calculating the projected future O&M costs in the net present value ("NPV") evaluation. The estimated auxiliary power requirements were based on S&L's knowledge of the quantity and cost of the utilities required to operate various other new or upgraded control equipment. Big Rivers will consider parasitic load as part of the evaluation criteria before choosing a specific supplier for each project.

Q. Is Big Rivers seeking to recover costs associated with this reduction in net generation due to parasitic load in this application?

A. No. Parasitic load was not included in any of the production cost models that Big Rivers used to calculate the estimated O&M cost that Big Rivers is seeking to recover through its environmental surcharge mechanism.

V. DETERMINATION OF PROJECTS: S&L STUDY

Q. How did Big Rivers determine which technology options should be implemented to comply with the environmental requirements noted in this application?

A. Big Rivers retained S&L, an engineering and consulting firm specializing in professional services for the electric power industry, to perform a focused compliance study addressing recently-issued, proposed and pending environmental regulations and legislation, and the potential impacts these initiatives may have on operations at Big Rivers' Coleman, Wilson, and Sebree (Reid, Green and HMP&L Units) generating stations.

Q. Please describe the S&L study.

A. The S&L study was a focused three-phase effort to determine the best methods and technologies for Big Rivers to achieve compliance with environmental regulations. Phase I was a review of existing, proposed and expected future EPA regulations, Phase II was for identification of compliance options, and Phase III was for screening and analyzing the available options for the purpose of choosing the most cost effective approach for Big Rivers to meet the requirements of the existing and proposed regulations. This study is described more fully in the direct testimony of Mr. DePriest.

Q. Did S&L conduct a technology screening analysis to determine which set of alternatives would allow Big Rivers to comply with the applicable environmental requirements on a cost-effective basis?

A. Yes. Phase III of the S&L study was dedicated to technology evaluation, including a NPV analysis based on capital and O&M costs, for the purpose of selecting the optimum solution for Big Rivers to reduce its emissions sufficiently to comply with the new, proposed and existing EPA regulations.

Q. What material information did Big Rivers provide to S&L for use in its study?

A. Big Rivers provided S&L with plant facility descriptions, historical plant operating data, recent emissions test data and other key input information that is shown in Exhibit Berry-3 (Tables 1-2 through 1-4).

Q. What technology alternatives are recommended by S&L in order for Big Rivers to achieve compliance with the applicable environmental requirements?

A. Exhibit Berry-4 (Table 5-1) shows all of the screened technologies that were considered in the S&L study with estimated capital and O&M costs for the different options. All of the options that appear on Exhibit Berry-4 (Table 5-1), but that are not included in Exhibit Berry-2 (2012 Plan), are considered alternative technologies.

Q. What options were considered by S&L for compliance with the CSAPR and National Ambient Air Quality Standards ("NAAQS") requirements that were not recommended for inclusion in the 2012 Plan?

A. As Exhibit Berry-5 (Tables 6-1, 6-2, and 6-3) shows, advanced low NOx burner systems on the Coleman Units and an SCR on the Green Unit 1 were considered for CSAPR and NAAQS compliance, but were not recommended for inclusion in the 2012 Plan because potential NAAQS reductions are not expected to be published until 2016 with compliance possibly due in 2018. At this time, anticipated NAAQS reductions are merely speculative and will be addressed in future environmental compliance plans.

Q. What options were considered by S&L for compliance with the MATS Rule that were not recommended for inclusion in the 2012 Plan?

A. Exhibit Berry-6 (Table 6-5) shows that electrostatic precipitator upgrades at Coleman, Green, Wilson and HMP&L, along with low oxidation catalyst in the existing Wilson and HMP&L SCR's, were considered for compliance with the Hazardous Air Pollutant Maximum Achievable Control Technology ("HAPS MACT") rule, but not recommended for inclusion in the 2012 Plan. While the study was in progress, the HAPS MACT rule was replaced with the more recent MATS regulation that exempted condensable particulate emissions from the total particulate emission limit set by HAPS MACT, and these options were no longer necessary for compliance. However, additional precipitator testing was recommended to determine if the existing equipment could handle the additional particulate loading from the activated carbon and dry sorbent injections.

Q. What other issues, if any, did S&L consider that are not included in this application?

A. The S&L study included consideration of EPA-proposed regulations under §316(b) of the Clean Water Act - Waste Water Intake Impingement

Mortality & Entrainment, Waste Water Discharge, and Coal Combustion Residuals ("CCR"). Mr. Shaw's direct testimony discusses the recommendations regarding these rules. Big Rivers will continue to monitor the rules and will consider mitigation strategies in future environmental compliance plans.

Q. Will the installation of the projects in the 2012 Plan replace or cause existing facilities to be removed from service?

A. Yes. The new FGD system at the Wilson facility will replace some existing FGD assets that have been in service since the plant's commissioning. The assets being removed from service will be retired.

Q. Did Big Rivers consider Demand Side Management ("DSM") and energy efficiency as options for complying with CSAPR and MATS?

A. Yes. Big Rivers recently filed tariffs for DSM/energy efficiency programs with the Commission, and although DSM and energy efficiency is and will continue to be an area of focus for Big Rivers, the magnitude of potential savings from DSM and energy efficiency is insufficient to materially assist Big Rivers in complying with CSAPR and MATS.

Q. Did Big Rivers look at other options to comply with CSAPR and MATS?

A. Yes. The other options that were considered are discussed in the testimonies of Mr. Hite and Mr. DePriest.

VI. CERTIFICATES OF PUBLIC CONVENIENCE & NECESSITY

Q. Is Big Rivers requesting CPCNs in this proceeding?

A. Yes.

Q. Specifically, which components of the 2012 Plan are the subjects of requests for CPCNs?

A. Referring to Exhibit Berry-2, all of the projects listed in Big Rivers' 2012 Plan are the subjects of a request for CPCNs, except for the projects that will be installed at HMP&L Station Two.

Q. How does Big Rivers plan to construct the facilities included in the 2012 Plan?

A. Big Rivers will use a variety of methods to construct these projects. It is Big Rivers' intention to hire an Architectural/Engineering ("A/E") firm to develop technical specifications for the projects. Based on bids received from these A/E specifications, contracts will be awarded to equipment suppliers and construction firms. Although it is anticipated that the majority of these projects will be separated into equipment supply and installation components, there may be some smaller contracts that could be supply and install contracts.

Q. Will Big Rivers begin planning for the commencement of construction for the projects in the 2012 Plan prior to the conclusion of this proceeding and the issuance of the requested CPCNs?

A. Yes. Big Rivers has begun to execute project management details for some of the projects in the 2012 Plan such as interviewing A/E firms for preparation of detailed project specifications. No financing arrangements will be finalized, nor will any construction begin, prior to Big Rivers receiving the requested CPCNs.

Q. Given the tight compliance and construction timeline that you have outlined, could Big Rivers have reasonably filed this application sooner?

A. No. The requirements of the current proposed EPA regulations have been a moving target for the last several years. First, CAIR was proposed with its emission limits and allowance allocations, CAIR changed to the Clean Air Transport Rule ("CATR") and a new set of values, CATR was remanded and CAIR reemerged, CATR was replaced with CSAPR, CSAPR was stayed by the courts and CAIR reemerged again. Big Rivers determined it was appropriate to delay publishing an environmental compliance plan until now, when there is a higher degree of certainty regarding future requirements.

Although CSAPR has been stayed, Big Rivers does not expect the requirements to change materially. In addition, Big Rivers does not expect MATS to change materially, although legal challenges could delay the implementation date of this regulation.

Q. Are there other timing considerations associated with the construction of the projects included in the 2012 Plan?

A. Before Big Rivers can actually begin construction of the projects in its 2012 Plan, it must obtain revised Title V permits from the EPA, secure the CPCNs from the Commission, acquire Commission approval to recover its investment and increased operating costs through the environmental surcharge mechanism, and arrange for financing of the projects.

Q. Can Big Rivers complete construction of the projects you have described in time to use the facilities to meet the compliance requirements in the 2012 Plan?

A. Big Rivers will not be able to complete construction of its FGD projects at Wilson and HMP&L, or its SCR project at Green Unit 2, in time to meet current CSAPR compliance requirements for SO_2 and NO_X in 2014. However, the CSAPR rule has been stayed by the DC Circuit Court of Appeals. If the CSAPR rule is reinstated as written in 2012, compliance dates are expected to be delayed at least one year. If the new compliance requirements are put into effect in 2015 as currently written and Big Rivers does not have sufficient quantities of allowances banked, it will either purchase allowances or curtail generation to achieve compliance until all of the projects are completed. Big Rivers expects to have its projects for MATS compliance completed prior to the expected effective date in the first quarter of 2016.

VII. CONCLUSION

Q. What are your conclusions and recommendations to the Commission in this proceeding?

A. Based on the results of the technology screening and cost estimating performed in the S&L study, the Big Rivers 2012 Plan is the most cost effective approach to meet the requirements of the existing and proposed regulations. I recommend that the Commission approve Big Rivers' 2012 Plan, grant the CPCNs as requested, and approve recovery of Big Rivers' prudently-incurred costs through the environmental surcharge mechanism as proposed. The facilities and actions contained in the 2012 Plan are necessary to comply with the environmental laws and regulations. The proposed timelines and costs associated with implementing the 2012 Plan are fair, just and reasonable.

Q. Does this conclude your testimony?

A. Yes.

BIG RIVERS ELECTRIC CORPORATION

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

CASE NO. 2012-00063

VERIFICATION

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

Robert W. Berry
Robert W. Berry

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Robert W. Berry on this the 26th day of March, 2012.

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

Professional Summary

Robert W. Berry
Vice President, Production
Big Rivers Electric Corporation
201 3rd Street
Henderson, Kentucky 42420
(270) 844-6031

Professional Experience

Big Rivers Electric Corp. 2009 to present

Vice President, Production

Western Kentucky Energy 1998 - 2009

General Manager

Plant Manager, Reid/Green/HMP&L Station

Plant Manager, Coleman Station

Maintenance Manager, Reid/Green/HMP&L Station

Big Rivers Electric Corp. 1981 - 1998

Maintenance Superintendent, Green Station

Maintenance Supervisor, Green Station

Various and Sundry Maintenance and Operations Positions

Education

BS Business Management

Mid-Continent University

Associate in Applied Science, Mechanical Engineering Technology

University of Kentucky Community College System

Mechanical Maintenance Apprentice Program

Certified by Kentucky Department of Higher Education

Management, Leadership and Communication Training

Employer-sponsored programs

Big Rivers Electric Corporation
2012 Environmental Compliance Plan

Project Number	Pollutant	Control Facility	Plant	Environmental Regulation or Regulatory Requirement	Permit	CPCN Filed	Projected Completion	Projected Capital Cost ($ Million) [1]
4	SO_2	Flue Gas Desulfurization ("FGD" or "Scrubber")	Wilson Unit 1	Clean Air Act (1990), Cross State Air Pollution Rule ("CSAPR")	Title V Permit	Yes	2016	139.00
5	NO_X	Selective Catalytic Reduction ("SCR") @85% Removal	Green Unit 2	Clean Air Act (1990), Cross State Air Pollution Rule ("CSAPR")	Title V Permit	Yes	2015	81.00
6	SO_2, NO_X	Convert Burners to Natural Gas	Reid Unit 1	Clean Air Act (1990), Cross State Air Pollution Rule ("CSAPR")	Title V Permit	Yes	2014	1.20
7	SO_2	Install Additional Recycle Pump & New Motors On ID Fans	HMP&L Unit 1 [1,2]	Clean Air Act (1990), Cross State Air Pollution Rule ("CSAPR")	Title V Permit	No	2015	3.15
			HMP&L Unit 2 [1,2]		Title V Permit		2015	3.15
8	Mercury	Activated Carbon Injection, Dry Sorbent Injection and Monitors	Coleman Unit 1	Clean Air Act (1990), Mercury and Air Toxics Standards ("MATS") Rule	Title V Permit	Yes	2016	9.48
			Coleman Unit 2		Title V Permit		2016	9.48
			Coleman Unit 3		Title V Permit		2016	9.48
9	Mercury	Activated Carbon Injection, Dry Sorbent Injection and Monitors	Wilson Unit 1	Clean Air Act (1990), Mercury and Air Toxics Standards ("MATS") Rule	Title V Permit	Yes	2016	11.24
10	Mercury	Activated Carbon Injection, Dry Sorbent Injection and Monitors	Green Unit 1	Clean Air Act (1990), Mercury and Air Toxics Standards ("MATS") Rule	Title V Permit	Yes	2016	9.24
			Green Unit 2		Title V Permit		2016	9.24
11	Mercury	Particulate Monitors	HMP&L Unit 1 [1,2]	Clean Air Act (1990), Mercury and Air Toxics Standards ("MATS") Rule	Title V Permit	No	2016	0.24
			HMP&L Unit 2 [1,2]		Title V Permit		2016	0.24

Total ($ Million) 286.14

Footnotes - 1.- Cost shown includes HMP&L's share of capital project.
2.- Cost shown includes HMP&L's share of the O&M expenses.

Big Rivers Electric Corporation
2012 Environmental Compliance Plan

Project Number	Pollutant	Control Facility	Plant	Projected Annual Incremental O&M Costs ($ Million) as Calculated by S&L on a Generation Baseline from Big Rivers 2010 Performance Metrics [2]											
				2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
4	SO_2	Flue Gas Desulfurization ("FGD" or "Scrubber")	Wilson Unit 1					0.76	0.78	0.80	0.82	0.84	0.86	0.88	0.91
5	NO_X	Selective Catalytic Reduction ("SCR") @85% Removal	Green Unit 2				1.58	1.62	1.66	1.70	1.75	1.79	1.84	1.88	1.93
6	SO_2, NO_X	Convert Burners to Natural Gas	Reid Unit 1			0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	SO_2	Install Additional Recycle Pump & New Motors On ID Fans	HMP&L Unit 1 [1,2]				0.41	0.42	0.43	0.44	0.45	0.46	0.47	0.49	0.50
			HMP&L Unit 2 [1,2]				0.41	0.42	0.43	0.44	0.45	0.46	0.47	0.49	0.50
8	Mercury	Activated Carbon Injection, Dry Sorbent Injection and Monitors	Coleman Unit 1					1.24	1.27	1.30	1.33	1.36	1.40	1.43	1.47
			Coleman Unit 2					1.24	1.27	1.30	1.33	1.36	1.40	1.43	1.47
			Coleman Unit 3					1.24	1.27	1.30	1.33	1.36	1.40	1.43	1.47
9	Mercury	Activated Carbon Injection, Dry Sorbent Injection and Monitors	Wilson Unit 1					2.99	3.07	3.14	3.22	3.30	3.38	3.47	3.56
10	Mercury	Activated Carbon Injection, Dry Sorbent Injection and Monitors	Green Unit 1					1.63	1.67	1.72	1.76	1.80	1.85	1.89	1.94
			Green Unit 2					1.63	1.67	1.72	1.76	1.80	1.85	1.89	1.94
11	Mercury	Particulate Monitors	HMP&L Unit 1 [1,2]					0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.03
			HMP&L Unit 2 [1,2]					0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.03
							2.40	13.23	13.57	13.90	14.25	14.61	14.97	15.35	15.73

Footnotes - 1.- Cost shown includes HMP&L's share of capital project.
2.- Cost shown includes HMP&L's share of the O&M expenses.

Big Rivers Electric Corporation
2012 Environmental Compliance Plan
Plant Facility Information provided to Sargent & Lundy

Table 1-2 — Facility Baseline Summary for Coleman & Wilson

Parameter	Coleman Unit C01		Coleman Unit C02		Coleman Unit C03		Wilson Unit W01	
Gross Unit Output (MW)	160		160		165		440	
Full Load Heat Input (MMBtu/hr)	1,800		1,800		1,800		4,585	
Primary Fuel	Illinois Basin bituminous		Illinois Basin bituminous		Illinois Basin bituminous		Illinois Basin bituminous	
Secondary Fuel	N/A		N/A		N/A		Pet Coke Pelletized Fines #2 Fuel Oil	
Unit Description	Dry bottom wall-fired boiler		Dry bottom wall-fired boiler		Dry bottom wall-fired boiler		Dry bottom wall-fired boiler	
NO_x Control	LNB & ROFA		LNB & OFA		LNB & OFA		LNB/OFA/SCR	
PM Control	ESP		ESP		ESP		ESP	
SO_2 Control	Wet Limestone FGD		Wet Limestone FGD		Wet Limestone FGD		Wet Limestone FGD	
Condenser Cooling System	Once-through cooling		Once-through cooling		Once-through cooling		Closed cycle cooling	
Baseline Average Annual Heat Input(1) (MMBtu)	11,784,789		11,787,242		12,570,106		37,043,481	
2010 Annual Heat Input (MMBtu)	11,254,853		9,544,382		12,195,952		36,221,670	
Baseline Annual SO_2 Emissions(2) (tpy) / (lb/MMBtu)	1,473	0.25	1,473	0.25	1,571	0.25	9,438	0.51
Annual NO_x Emissions (2010) (3) (tpy) / (lb/MMBtu)	1,858	0.33	1,585	0.33	2,044	0.34	934	0.053
Ozone Season NO_x Emissions (2010) (3) (tons) / (lb/MMBtu)	733	0.33	735	0.34	857	0.34	378	0.050

(1) Baseline average annual heat inputs provided in this table represent the average of the three highest heat input years during the baseline years 2006-2010.

(2) Baseline annual SO_2 emissions represent the average of the three highest emission years (2006 – 2010); however, baseline SO_2 emissions from Coleman Units C01, C02, and C03 were adjusted to an annual average emission rate of 0.25 lb/MMBtu based on information provided by BREC.

(3) Baseline NO_x emission rates are calculated using 2010 NO_x emissions and 2010 heat inputs.

Big Rivers Electric Corporation
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Plant Facility Information provided to Sargent & Lundy

Table 1-3 — Facility Baseline Summary for Sebree

Parameter	Green Unit G01		Green Unit G02		Henderson Unit H01		Henderson Unit H02		Reid Unit R01		Reid Unit RT	
Gross Unit Output (MW)	252		244		172		165		72		70	
Full Load Heat Input (MMBtu/hr)	2,569		2,569		1,624		1,624		911		803	
Primary Fuel	Illinois basin bituminous		Illinois basin bituminous		Illinois basin bituminous		Illinois basin bituminous		Illinois basin bituminous		Natural Gas	
Secondary Fuel	Pet Coke		Pet Coke		N/A		N/A		N/A		Oil	
Unit Description	Dry bottom wall-fired boiler		Dry bottom wall-fired boiler		Dry bottom wall-fired boiler		Dry bottom wall-fired boiler		Dry bottom wall-fired boiler		Combustion Turbine	
NOx Control	LNB		LNB		LNB/SCR		LNB/SCR		LNB			
PM Control	ESP		ESP		ESP		ESP		Cyclone ESP			
SO_2 Control	Wet Lime FGD		Wet Lime FGD		Wet Lime FGD		Wet Lime FGD					
Condenser Cooling System	Closed cycle cooling		Closed cycle cooling		Closed cycle cooling		Closed cycle cooling		Once-through cooling			
Baseline Average Annual Heat Input(1) (MMBtu)	20,128,359		20,347,531		12,823,005		13,214,893		2,240,807		87,379	
2010 Annual Heat Input (MMBtu)	19,866,020		20,128,970		13,003,466		12,118,692		1,962,424		126,361	
Baseline Annual SO_2 Emissions(2) (tpy) / (lb/MMBtu)	1,873	0.19	1,414	0.14	2,227	0.35	2,745	0.42	5,066	4.52	5	0.12
Annual NOx Emissions (2010) (3) (tpy) / (lb/MMBtu)	2,050	0.21	2,168	0.22	460	0.071	418	0.069	512	0.52	45	0.71
Ozone Season NOx Emissions (2010) (3) (tons) / (lb/MMBtu)	789	0.20	890	0.21	208	0.074	179	0.066	193	0.47	33	0.70

Big Rivers Electric Corporation
2012 Environmental Compliance Plan
Plant Facility Information provided to Sargent & Lundy

Table 1-4 — MACT Emission Test Data

Proposed MACT Emission Limits		Stack Emission Test Data[1]						
		Coleman	Wilson	Green 1	Green 2	HMP&L 1	HMP&L 2	Reid 1
a. Total particulate matter (TPM)	0.030 lb/MMBtu	0.0398	0.0196	0.0195	0.0169	0.0319	0.0324	0.269[2]
OR								
Total non-Hg HAP metals	0.000040 lb/MMBtu	0.0000910	0.0000591	0.0000906	0.0000678	0.0000959	0.0001203	N/A
b. Hydrogen chloride (HCl)	0.0020 lb/MMBtu	0.000236	0.000074	0.000281	0.000334	0.001670	0.001370	0.068
OR								
Sulfur dioxide (SO_2)	0.20 lb/MMBtu	0.250	0.510	0.186	0.139	0.347	0.415	4.52
c. Mercury (Hg)	1.2 lb/TBtu	3.52	1.77	3.09	2.58	0.62	0.47	6.5

(1) Green cells indicate baseline emissions below the applicable MACT emission limit. Red cells indicate baseline emissions above the applicable MACT emission limit.

(2) Condensable particulate emission data was not available for Reid. Value shown is filterable particulate matter only.

Big Rivers Electric Corporation
2012 Environmental Compliance Plan
Screened Technologies considered in Sargent & Lundy Study

Table 5-1 — Estimated Costs for Technologies Considered (Air Pollution Compliance) (Additional Costs to the Current Budgets and Expenses)

Pollutant	Station / Unit	Technology	Capital Cost (2011 $ Millions)	O&M Cost (2011 $ Millions)	Comments
SO_2 Control	Wilson	New WFGD Absorber Vessel	139.0	0.69	Replacement of the existing horizontal scrubber with a new state-of-the-art vertical scrubber. Existing limestone preparation and dewatering systems would be reused to support new vessel. (Capital cost estimate was based on SESS budget proposal number 4296 provided 11/11/11)
	Reid 1	Natural Gas Conversion	1.2	3.84 [1] (Fuel Cost - 5.61, Other:- 1.77)	Reid already has natural gas supply and burners in place. Based on discussions with Big Rivers these have not been placed into service. The capital allowance is an approximation of maintenance, testing and other incurred fees to start up the existing system.
	Green 1/2	Natural Gas Conversion	25.6 – 27.6 (per unit)	47.2 [1] (per unit)	The available gas supply line near Green currently has capacity for conversion of one (1) of the green units. If both are converted, the higher capital value would need to be applied to both for a new supply line. The conversion cost includes installation of new burners, a flue gas recirculation system and a natural gas supply system.
	HPM&L 1/2	Existing WFGD with Increased L/G Upgrades	3.15 (per unit)	0.38 (per unit)	Based on received data the current HMP&L scrubbers are capable of increasing removal efficiency by operating a second recirculation pump. The capital cost for this modification includes installation of a third recycle pump to maintain system redundancy and tipping of the existing ID fans with installation of new motors to account for additional system pressure losses as a result of increased removal spray flow.

Big Rivers Electric Corporation
2012 Environmental Compliance Plan
Screened Technologies considered in Sargent & Lundy Study

Table 5-1 — Estimated Costs for Technologies Considered (Air Pollution Compliance)
(Additional Costs to the Current Budgets and Expenses)

Pollutant	Station / Unit	Technology	Capital Cost (2011 $ Millions)	O&M Cost (2011 $ Millions)	Comments
NO_X Control	Coleman 1/2/3	SNCR (Unit 1)	2.4	1.56	Unit 1 currently has the ROFA system installed for NOX control. Installation of a SNCR system would provide the desired removal efficiencies at a reduced cost over conventional SNCR technologies.
		SNCR (Unit 2 & 3)	2.7 (per unit)	1.58 (per unit)	Cost is based on a complete system with necessary piping, valves, heating units, reagent preparation equipment, etc.
		Advanced (3rd Generation) Low-NO_X Burners	5.94 (per unit)	0	Upgrade includes replacement of existing first generation Low-NOX burners with new advanced burners.
	Wilson	Advanced (3rd Generation) Low-NO_X Burners	8.61	0	Upgrade includes replacement of existing first generation Low-NOX burners with new advanced burners.

Big Rivers Electric Corporation
2012 Environmental Compliance Plan
Screened Technologies considered in Sargent & Lundy Study

Table 5-1 — Estimated Costs for Technologies Considered (Air Pollution Compliance)
(Additional Costs to the Current Budgets and Expenses)

Pollutant	Station / Unit	Technology	Capital Cost (2011 $ Millions)	O&M Cost (2011 $ Millions)	Comments
NO_X Control	Green 1/2	SNCR	3.5 (per unit)	1.61 (per unit)	Cost is based on a complete system with necessary piping, valves, heating units, reagent preparation equipment, etc.
		SCR	81 (per unit)	1.47 (per unit)	Capital cost for installation of an SCR at Green includes foundations, duct modifications, steel structures, SCR catalyst and new ID fans for the increased pressure loss.
		SCR Catalyst	2.43	0	The catalyst cost for replacement of all three (3) layers (not including labor). It's anticipated that a single layer would have to be replaced every two (2) years and the remaining layers would be rotated. A new set of catalyst would be required every six (6) years. $0.41M is the annualized cost for the 6-year cycle life of the catalyst.
		Natural Gas Conversion	See SO_2 Above	See SO_2 Above	Conversion to natural gas will provide a reduction in NOX emissions in addition to the SO2 reductions. See SO2 section above for details of installation.
		Advanced (3rd Generation) Low-NO_X Burners + OFA	8.64	0	Upgrade includes replacement of existing first generation Low-NOX burners with new advanced burners and over fire air.
	Reid 1	Natural Gas Conversion	See SO_2 Above	See SO_2 Above	Conversion to natural gas will provide a substation reduction in NOX emissions in addition to the SO2 reductions. See SO2 section above for details of installation.

Big Rivers Electric Corporation
2012 Environmental Compliance Plan
Screened Technologies considered in Sargent & Lundy Study

Table 5-1 — Estimated Costs for Technologies Considered (Air Pollution Compliance)
(Additional Costs to the Current Budgets and Expenses)

Pollutant	Station / Unit	Technology	Capital Cost (2011 $ Millions)	O&M Cost (2011 $ Millions)	Comments
HCl	All Units	HCl Monitor	0.24 (per stack)	0.02 (per stack)	Typical cost for installation of an HCl monitor is shown. Installation is not usually dependant on unit size or other operational parameters. Required for units not able to use SO2 emissions for MACT compliance.
Hg	Coleman 1/2/3	Activated Carbon Injection System	4.0 (per unit)	0.81 (per unit)	Complete carbon injection systems are included in the estimated capital costs provided. System includes foundations, silo, transport piping, injection lances, blowers and all other necessary components of a complete activated carbon injection system.
	Wilson		4.5	2.19	
	Green 1/2		4 (per unit)	1.14 (per unit)	
Condensable Particulates	Coleman 1/2/3	Hydrated Lime DSI	5.0 (per unit)	0.27 (per unit)	Complete dry sorbent injection systems are included in the estimated capital costs provided. System includes foundation, silo, transport piping, injection lances, blowers and all other necessary components of a complete hydrated lime injection system.
	Green 1/2		5.0 (per unit)	0.32 (per unit)	
	Wilson	Hydrated Lime DSI + Low Oxidation Catalyst	6.5	0.50	Complete dry sorbent injection systems as well as upgrading the existing catalyst are included in total cost estimate. The costs are on a per unit basis and include complete unitized systems with all necessary components (silo, blowers, piping, lances, etc.)
	HMP&L 1/2		6.0 (per unit)	0.29 (per unit)	

Big Rivers Electric Corporation
2012 Environmental Compliance Plan
Screened Technologies considered in Sargent & Lundy Study

Table 5-1 — Estimated Costs for Technologies Considered (Air Pollution Compliance)
(Additional Costs to the Current Budgets and Expenses)

Pollutant	Station / Unit	Technology	Capital Cost (2011 $ Millions)	O&M Cost (2011 $ Millions)	Comments
Filterable Particulates	Coleman 1/2/3	Upgrade Existing with Advanced Electrodes and High Frequency TR Sets	2.4 (per unit)	0.06 (per unit)	Implementation of advanced electrode technology and the addition of high frequency transformer rectifier sets may be needed for each of the units listed. Choice of modification of the existing ESP at each unit will be decided based on the particular unit's present performance capability and the chosen technologies for mitigating other regulated pollutants.
	Wilson		4.3	0.15	
	Green 1/2		3.1 (per unit)	0.05 (per unit)	
	HMP&L 1/2		2.5 (per unit)	0.08 (per unit)	
Total Particulates	Coleman 1/2/3	Particulate Matter Monitor	0.24 (per stack)	0.02 (per stack)	Particulate monitors will be needed at the listed sites to demonstrate compliance with the anticipated MACT regulations. Typical cost for installation of an PM monitor is shown. Installation is not usually dependent on unit size or other operational parameters.
	Wilson				
	Green 1/2				

Footnote(s):

1. Natural gas O&M cost includes fuel cost and were developed based on baseline heat inputs and the economic parameters shown in Table 1-1. O&M savings that are associated with day-to-day operation and outage work from conversion to natural gas have been estimated based on information provided by Big Rivers and S&L's experience.

Big Rivers Electric Corporation
2012 Environmental Compliance Plan
Options to Comply with CSPAR and NAAQS

Table 6-1 – SO_2 Compliance Summary

Unit	Baseline Heat Input (MMBtu)	Baseline SO_2 Emissions (tpy)	Current Annual SO_2 Emission Rate (lb/MMBtu)	Technology Selection	Estimated New SO_2 Emissions (tpy)	Estimated New Annual SO_2 Emission Rate (lb/MMBtu)	Net Present Value (2011 $ Million)
Coleman Unit C01	11,784,789	2,331	0.396	Return to As-Designed Operation	1,473	0.250	N/A
Coleman Unit C02	11,787,242	2,411	0.409	Return to As-Designed Operation	1,473	0.250	N/A
Coleman Unit C03	12,570,106	2,406	0.383	Return to As-Designed Operation	1,571	0.250	N/A
Wilson Unit W01	37,043,481	9,438	0.510	New Tower Scrubber - 99% removal	1,049	0.057	$82.5
Green Unit G01	20,128,359	1,873	0.186	None	1,873	0.186	N/A
Green Unit G02	20,347,531	1,414	0.139	None	1,414	0.139	N/A
HMP&L Unit H01	12,823,005	2,227	0.347	Run both pumps install third pump as spare	788	0.123	-$2.1
HMP&L Unit H02	13,214,893	2,745	0.415	Run both pumps install third pump as spare	835	0.126	-$2.1
Reid Unit R01	2,240,807	5,066	4.522	Natural Gas with Existing Burners	1	0.001	$8.9
Reid Unit RT	87,379	5	0.117	None	5	0.117	N/A
TOTAL	142,027,592	29,916	0.421	N/A	10,482	0.148	$87.2

Big Rivers Electric Corporation
2012 Environmental Compliance Plan
Options to Comply with CSPAR and NAAQS

Table 6-2 – NO_x CSAPR Compliance Summary

Unit	Baseline Heat Input (MMBtu)	Baseline NO_X Emissions (tpy)	Current Annual NO_X Emission Rate (lb/MMBtu)	Technology Selection	Estimated New NO_X Emissions (tpy)	Estimated New Annual NO_X Emission Rate (lb/MMBtu)	Net Present Value (2011 $ Million)
Coleman Unit C01	11,254,853	1,858	0.330	Advanced Burners	1,672	0.297	$0.32
Coleman Unit C02	9,544,382	1,585	0.332	Advanced Burners	1,427	0.299	$0.32
Coleman Unit C03	12,195,952	2,044	0.335	Advanced Burners	1,840	0.302	$0.32
Wilson Unit W01	36,221,670	934	0.052	None	934	0.052	N/A
Green Unit G01	19,866,020	2,050	0.206	None	2,050	0.206	N/A
Green Unit G02	20,128,970	2,168	0.215	SCR @ 85% Removal	325	0.032	$43.9
HMP&L Unit H01	13,003,466	460	0.071	None	460	0.071	N/A
HMP&L Unit H02	12,118,692	418	0.069	None	418	0.069	N/A
Reid Unit R01	1,962,424	512	0.522	Natural Gas with Existing Burners	292	0.298	See SO_2
Reid Unit RT	126,361	45	0.708	None	45	0.708	N/A
TOTAL	136,422,791	12,074	0.177	N/A	9,462	0.139	$44.9

Big Rivers Electric Corporation
2012 Environmental Compliance Plan
Options to Comply with CSPAR and NAAQS

Table 6-3 – NO_x NAASQ Compliance Summary

Unit	Baseline Heat Input (MMBtu)	Baseline NO_X Emissions (tpy)	Current Annual NO_X Emission Rate (lb/MMBtu)	Technology Selection	Estimated New NO_X Emissions (tpy)	Estimated New Annual NO_X Emission Rate (lb/MMBtu)	Net Present Value (2011 $ Million)
Coleman Unit C01	11,254,853	1,858	0.330	Advanced Burners	1,672	0.297	$0.32
Coleman Unit C02	9,544,382	1,585	0.332	Advanced Burners	1,427	0.299	$0.32
Coleman Unit C03	12,195,952	2,044	0.335	Advanced Burners	1,840	0.302	$0.32
Wilson Unit W01	36,221,670	934	0.052	None	934	0.052	N/A
Green Unit G01	19,866,020	2,050	0.206	SCR @ 85% Removal	307	0.031	$46.5
Green Unit G02	20,128,970	2,168	0.215	SCR @ 85% Removal	325	0.032	$43.9
HMP&L Unit H01	13,003,466	460	0.071	None	460	0.071	N/A
HMP&L Unit H02	12,118,692	418	0.069	None	418	0.069	N/A
Reid Unit R01	1,962,424	512	0.522	Natural Gas with Existing Burners	292	0.298	See SO_2
Reid Unit RT	126,361	45	0.708	None	45	0.708	N/A
TOTAL	136,422,791	12,074	0.177	N/A	7,720	0.113	$91.4

Big Rivers Electric Corporation
2012 Environmental Compliance Plan

Table 6-5 - MACT TPM Compliance Summary

Unit	Baseline Filterable PM Emission Rate (lb/MMBtu)	Baseline Condensable PM Emission Rate (lb/MMBtu)	Baseline Total PM Emission Rate (lb/MMBtu)	Required Percent Reduction for MACT Compliance	Technology Selection	Net Present Value (2011$ Million)
Coleman Unit C01	0.0220	0.0178	0.0398	25%	Hydrated Lime DSI & ESP Upgrades	$10.3
Coleman Unit C02						$10.3
Coleman Unit C03						$10.3
Wilson Unit W01	0.00912	0.01043	0.0196	N/A	Low Oxidation Catalyst & ESP Upgrades	$11.2
Green Unit G01	0.0084	0.0111	0.0195	N/A	Hydrated Lime DSI & Potential ESP Upgrades	$11.2
Green Unit G02	0.0046	0.0123	0.0169	N/A	Hydrated Lime DSI & Potential ESP Upgrades	$11.2
HMP&L Unit H01	0.0177	0.0142	0.0319	6%	Hydrated Lime, Low Oxidation Catalyst, & ESP Upgrades	$11.2
HMP&L Unit H02	0.0120	0.0204	0.0324	7%	Hydrated Lime, Low Oxidation Catalyst, & ESP Upgrades	$11.2
Reid Unit R01	0.269	N/A	>0.030	90%	Natural Gas Conversion	N/A
TOTAL						$86.9

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

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

DIRECT TESTIMONY

OF

WILLIAM DePRIEST
PRESIDENT AND DIRECTOR, DePRIEST CONSULTING, INC.

ON BEHALF OF

BIG RIVERS ELECTRIC CORPORATION

FILED: April 2, 2012

DIRECT TESTIMONY
OF
WILLIAM DePRIEST

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DIRECT TESTIMONY
OF
WILLIAM DePRIEST

I. INTRODUCTION

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

A. My name is William DePriest, and my Sargent & Lundy, LLC ("S&L") business address is 55 East Monroe Street, Chicago, Illinois, 60603. My position at S&L, prior to January 1, 2012, was Senior Vice President and Director of the Environmental Services Section in the Fossil Power Technologies Group. I held this position during the subject compliance planning study work performed for Big Rivers Electric Corporation ("Big Rivers"). I retired from S&L on January 1, 2012, and subsequently started working for a company by the name of DePriest Consulting, Inc. ("DPI"), which I started and which was retained by S&L for their continued support of Big Rivers. My position at DPI is President and Director, and the company address is 312 North East Avenue, Oak Park, Illinois, 60302.

Q. Please describe your job responsibilities.

A. While employed by S&L and during the time of the subject compliance planning work for Big Rivers, I directed the Environmental Services section of the Fossil Power Technologies Group at S&L. This group provided the technical and technology expertise to the Big Rivers project team during the course of the compliance planning study. I directly supervised these staff and reviewed their work as it pertained to the Big Rivers compliance study. Subsequent to my retirement on January 1, 2012, I have reviewed the ongoing study work as it pertains to the finalization of the hazardous air pollutant rules now known as the Mercury and Air Toxic Standard ("MATS") rule.

Q. Briefly describe your education and work experience.

A. In 1972, I graduated from Michigan Technological University with a Bachelor of Science Degree in Chemical Engineering. I have worked in the power industry for 39 years. The first 13 years after college were with the Babcock and Wilcox Company ("B&W") out of Barberton, Ohio. My responsibilities with B&W ranged from a field service engineer for coal-fired power plant emission control systems to Manager of Technology for the Environmental Controls Division. I have worked the last twenty-six years for S&L in a capacity that ranged from Environmental Technology Consultant in the Mechanical Analytical Division to Senior Vice President and Director of Environmental Services in the Fossil Power Technologies Group. Although I have retired from S&L, I have continued my working relationship with S&L as a consultant. A summary of my work experience, pertinent to my position at the time the study was performed, is provided in Exhibit DePriest-1.

Q. Are you a Registered Professional Engineer?

A. Yes. I am a Registered Professional Engineer from the State of Wisconsin.

Q. Have you previously testified before the Kentucky Public Service Commission ("Commission")?

A. No. However, as described in Exhibit DePriest-1, I have provided testimony and/or depositions regarding similar regulatory issues for the following clients:

1. Indianapolis Power & Light ("IPL") – Indiana Utility Regulatory Commission Cause No. 42170, regarding IPL's request for approval of a Certificate of Public Convenience and Necessity ("CPCN") to construct various Clean Coal Technology ("CCT") projects to address the NO_X State Implementation Plan ("SIP") call.
2. Indianapolis Power & Light ("IPL") – Indiana Utility Regulatory Commission Cause No. 42700, regarding IPL's request for modification of its CPCN issued in Cause No. 42170 to construct two additional CCT projects (the first step of IPL's Multi-Pollutant Plan).
3. Reliant Energy – Petition of Reliant Energy, Inc. for Approval of Environmental Cleanup Costs Plan in the State of Texas State Office of Administrative Hearing (SOAH) Docket No. 473-02-0473, PUC Docket No. 24835.
4. Texas Genco & Centerpoint Energy – Application of Texas Genco, LP and Centerpoint Energy Houston Electric, LLC, and Texas Genco, LP to determine stranded costs and other True-up balances pursuant to the Public Utilities Regulatory Policy Act ("PURPA") 39.262 PUC Docket No. 29526.
5. Mid America Energy – Their "Multi-Pollutant" Environmental Plan in the State of Iowa, Iowa Dept. of Commerce before the Iowa Utilities Board. Docket No. EPB-02-156.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the process that S&L used to identify candidate control technologies (including emission control equipment, gas conversion and coal switching at selected stations), evaluate these options, and select the most appropriate and cost-effective emissions reduction multi-pollutant emission compliance strategy for Big Rivers.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

1. Exhibit DePriest-1 – William DePriest Resume;
2. Exhibit DePriest-2 – Big Rivers Environmental Compliance Study SL-010881 dated February 13, 2012;
3. Exhibit DePriest-3 – Big Rivers Environmental Compliance Study Supplement - ESP Performance Based on Final MACT; and
4. Exhibit DePriest-4 – Big Rivers Environmental Compliance Study Supplement - Fuel Switching for CSAPR Compliance.

Q. Was the Environmental Compliance Study included in Exhibit DePriest-2 prepared under your direction and supervision?

A. Yes

III. QUALIFICATIONS OF SARGENT & LUNDY

Q. What analysis did Big Rivers ask S&L to perform?

A. Big Rivers asked S&L to perform a focused compliance study for its fossil-fired power plants addressing the recently issued, proposed, and pending environmental regulations as further described below, and the potential impacts these initiatives may have on control technology applications and operations at Big Rivers' Kenneth C. Coleman, D.B. Wilson, and Sebree generating stations. Note that the Sebree Station includes Big Rivers' Green Units 1 and 2, Reid Unit 1, the Reid Combustion Turbine Unit, and Henderson Municipal Power & Light's ("HMP&L's") Station Two Units 1 and 2, which are operated by Big Rivers. The purpose was to develop a cost-effective strategy for the above-mentioned generating stations to primarily comply with the Cross-State Air Pollution Rule ("CSAPR") and National Emissions Standards for Hazardous Air Pollutants (also known as Utility Maximum Achievable Control Technology ("Utility MACT")), although the impacts of other proposed and potential regulations were also considered.

Q. Why is S&L qualified to perform the environmental compliance study requested by Big Rivers?

A. S&L has considerable experience assisting utility clients with developing system-wide and unit-specific emission reduction programs to meet federal and state mandated emission compliance requirements. At the time that S&L began this work for Big Rivers, S&L had completed similar compliance planning activities for more than 40 other electric utilities. S&L also has considerable experience with the federal and state environmental regulations affecting power plant operations, as well as the specification, evaluation, selection and implementation of emission control technologies for both gas- and coal-fired utility power facilities. For example, S&L has provided, or is providing, engineering services for the implementation of over 75 flue gas desulfurization ("FGD") retrofit projects, over 60 selective catalytic reduction ("SCR") projects, over 70 mercury control projects, and over 15 sorbent injection projects, all of which are technologies that are recommended as part of the Big Rivers 2012 environmental compliance plan, which is provided as Exhibit Berry-2 in the Direct Testimony of Robert W. Berry (the "2012 Plan"). Note that S&L is an independent engineering and consulting company with no ties to any of the suppliers of the aforementioned technologies.

Q. Why is S&L considered by the utility industry to be independent and fair in the evaluation of environmental compliance plans for electric power plant operators?

A. Throughout our history (over 120 years) S&L has elected to take no vested interest in any technology or system that a utility may use to generate electricity or facilitate the generation of electricity, including air pollution control equipment. S&L's focus has always been providing consulting services to assist utilities with their generation planning and technology selection and engineering services to help implement those generation plans. Our history reflects this commitment to be an independent and fair evaluator of the candidate technologies available to meet a utility's ongoing generation needs.

IV. ENVIRONMENTAL COMPLIANCE STUDY

Q. Please provide an overview of the environmental compliance study that S&L performed.

A. The environmental compliance study that S&L performed identified and assessed the potential impacts of current, pending, and proposed environmental regulations on the generating stations owned or operated by Big Rivers, and identified candidate technologies that could contribute to Big Rivers' overall compliance strategy. We estimated the capital and operations & maintenance ("O&M") costs to apply the candidate technologies, and recommended the combination of technologies at each facility that would comprise the most cost-effective overall compliance strategy for Big Rivers' generating stations and HMP&L Station Two.

Q. Please describe the S&L study.

A. The environmental compliance study conducted by S&L was conducted in three phases. Phase I consisted of a focused evaluation of current, pending, and proposed environmental regulations as they apply to Big Rivers. Phase II of this study consisted of an evaluation of possible compliance strategies applicable to the regulatory requirements identified in Phase I. The candidate strategies developed were based on either installing new technologies to reduce emissions, upgrading existing equipment currently installed at the Big Rivers facilities to further reduce emissions, fuel (gas conversion or coal switching) changes, or combinations of the these strategies. Phase III of the study evaluated the costs and installation schedules associated with the candidate strategies, and included a recommendation for the most cost-effective compliance strategy for the Big Rivers facilities based on a Net Present Value ("NPV") analysis accounting for capital and O&M expenditures for each technology.

Q. What environmental regulations did S&L take into account in this study?

A. In the initial review, S&L accounted for the following rules and regulations as part of our study:

1. The Clean Air Interstate Rule ("CAIR");
2. CSAPR;
3. Utility MACT;
4. The Regional Haze Rule;
5. National Ambient Air Quality Standards ("NAAQS");
6. Multi-Pollutant and Greenhouse Gas Legislation;
7. Greenhouse Gas Tailoring Rule;
8. Section 316(b) Cooling Water Intake Regulations;
9. Coal Combustion Residuals Regulations; and
10. Wastewater Discharge Standards for the Steam Electric Power Point Source Category.

It is important to note, however, that the focus of the study was to recommend a compliance strategy for CSAPR and the Utility MACT rule.

Q. Did S&L conduct a technology screening analysis to determine which set of alternatives would allow Big Rivers to comply with the applicable environmental requirements on a cost-effective basis?

A. Yes. In Phase II of the study S&L considered commercially available technologies and combinations of technologies that had the potential to reach the goals of the regulatory requirements; and in Phase III of the study, S&L developed an NPV analysis of the candidate technologies accounting for capital and O&M expenditures for each. S&L used the NPV evaluation to determine which candidate strategy would allow Big Rivers to comply with the applicable environmental requirements on the most cost-effective basis.

Q. How did S&L determine which technology options could be implemented to comply with the environmental requirements noted in this application?

A. S&L has extensive experience with each of the candidate technologies included in the study, and a thorough understanding of the design, installation, operation, and effectiveness of each technology. S&L analyzed operating data and stack test data provided by Big Rivers to determine each facility's current emissions and what, if any, additional removal rates would be required to comply with the applicable regulatory requirements. In addition, we visited each facility to gain a better understanding of the site-specific operating conditions and limitations. We then applied our experience from past projects to determine the technologies, or combination of technologies, that would achieve the required removal rates to comply with the regulatory requirements.

Q. How did S&L estimate the capital costs of the various technology alternatives considered?

A. S&L maintains a cost database for past projects, and we were able to apply capital costs from recent similar projects, adjusting for boiler size and site-specific requirements at the Big Rivers facilities and HMP&L Station Two, to estimate the capital costs of the various technologies.

Q. How did S&L estimate the O&M costs of the various technology alternatives considered?

A: S&L estimated both the fixed and variable components of O&M costs for each candidate technology. Our fixed O&M cost estimates, which include operating and maintenance labor, maintenance materials and administrative labor, were based on our experience on similar projects, Big Rivers' operation and maintenance practices, and cost factors commonly used in the utility industry. Variable O&M costs are costs that tend to be directly proportional to the quantity of exhaust gas processed by the control system and to the composition of the fuel burned, including the cost of consumable commodities such as reagents and catalyst, and utilities, such as steam and auxiliary power required to operate the control systems. Our variable O&M cost estimates were based on a calculation of the quantity of reagent or catalyst consumed by the operation of the control technology, and our in-house database including information from Big Rivers on recent consumable pricing. Similarly, variable O&M costs associated with utilities (power, steam, *etc.*) consumption was estimated based on our knowledge of the quantities and costs of the utilities required to operate the various new or upgraded control equipment.

Q. How did S&L identify which of the technology alternatives to recommend to Big Rivers?

A. After identifying the candidate technologies and determining which technologies were capable of meeting the applicable regulatory requirements, S&L evaluated the costs of each candidate technology to identify the most cost-effective compliance approach. The recommendations that S&L made for technologies to comply with CSAPR were based on the combination of technologies capable of meeting Big Rivers' sulfur dioxide ("SO_2") and nitrogen oxide ("NO_X") allowance caps at the lowest NPV cost over a 20-year period. For example, for mercury compliance under Utility MACT, activated carbon in combination with dry sorbent injection was recommended based on (1) its well-demonstrated ability to consistently reduce mercury emissions while firing bituminous fuels such as those fired at the Big Rivers generating stations and HMP&L Station Two and (2) its more cost effective application compared to the other alternatives.

Q. Please describe the model(s) that S&L used to evaluate the cost effectiveness of the technology alternatives that were considered.

A: S&L used models and worksheets developed in-house to generate the capital and O&M cost estimates used in the compliance study. The basis of the models/worksheets used to develop the estimates for the Big Rivers plants and HMP&L Station Two was a compilation of actual cost data from recent S&L FGD, SCR, activated carbon injection ("ACI"), dry sorbent injection ("DSI"), and other comparable projects. These models/worksheets were used to calculate costs for each of the technology alternatives, and to determine the NPV of each technology over a projected 20-year life, taking into account economic data provided by Big Rivers. Alternatives were then compared to determine which had the lowest net present value while still complying with the applicable regulatory requirements.

Q. What types of input parameters and data did S&L use in its study? What material information did Big Rivers provide to S&L for use in its study?

A. S&L used existing plant design information including boiler size, capacity factors, heat input, fuel characteristics, existing plant configuration, and design drawings as inputs to its compliance study. Other inputs to the study included capital costs and O&M costs from other recent and similar projects. Information provided by Big Rivers for use in the study included boiler operating data and emissions test data, as well as economic inputs to the cost evaluation including discount rates, capital and O&M escalation rates, levelized fixed charge rates, operating labor rates, and auxiliary power costs.

Q. Please summarize the technology alternatives that were recommended by S&L in order for Big Rivers to achieve compliance with the applicable environmental requirements

A. To reduce SO_2 emissions as part of a CSAPR compliance strategy, the following technologies were recommended by S&L:

1. At Wilson Unit 1, S&L recommended replacing the existing wet FGD absorber, which is an older technology that is limited in its emission reduction capabilities, with a new absorber based on current technology that will achieve a higher SO_2 removal rate.
2. At HMP&L Station Two, S&L recommended upgrading the existing wet FGD control systems to increase removal of SO_2. This would be achieved by operating the existing spare spray level in the absorbers

along with adding a spare pump to maintain sufficient equipment redundancy.

3. At Reid Unit 1, natural gas conversion was recommended as part of the CSAPR compliance strategy to reduce system-wide emissions of SO_2 and NO_X. Conversion to natural gas would also exempt Reid Unit 1 from the Utility MACT requirements, and eliminate the need to install acid gas, mercury, and particulate matter controls.

To reduce NO_X emissions as part of a CSAPR compliance strategy, the following technologies were recommended by S&L:

1. At Green Unit 2, S&L recommended an SCR control system.
2. At Coleman Units 1, 2, and 3, S&L recommended low NOx burners. Note that this recommendation is based on two reasons. One is to provide Big Rivers with a degree of margin in its NO_X compliance strategy because the SCR at Big Rivers' Green generating station will result in only approximately 100 tons of NO_X emissions for the Big Rivers system below the CSAPR allocation. The second reason is that the SCR at Green will not be ready for service until 2015, and CSAPR requires compliance in 2012 resulting in 3 years of allowance purchases to meet the CSAPR allocation for NO_X. The burners at Coleman will provide an opportunity to reduce this burden on Big Rivers. Future allowance pricing will play a role in whether this recommendation should be exercised.

To reduce mercury and condensable particulate emissions as part of the original Utility MACT compliance strategy, activated carbon injection and dry sorbent injection were recommended by S&L at Coleman Units 1, 2, and 3, Wilson Unit 1, and Green Units 1 and 2. Although condensable particulate matter is no longer a concern under the MATS rule, we continue to recommend dry sorbent injection at Coleman Units 1, 2, and 3, Wilson Unit 1, and Green Units 1 and 2, as the presence of the dry sorbent lowers the activated carbon injection rates required to achieve mercury compliance. This change is described in an addendum to our report, which is included in this testimony as Exhibit DePriest-3 and which was prepared to address the final MATS requirements.

Also, low oxidation catalyst was originally recommended by S&L for the existing SCR control systems at the Wilson and HMP&L stations to reduce condensable particulate emissions. However, the final MATS rule includes only filterable particulate emissions requirements. Thus, we no longer recommend low oxidation catalyst for the existing SCR control systems at the Wilson and HMP&L stations. This change is also described in the above-mentioned addendum.

In further consideration of the total particulate emission requirements of the MATS rule, Electro-Static Precipitator ("ESP") upgrades, including advanced electrodes and high frequency transformer rectifier ("TR") sets were originally recommended for compliance at the Coleman and Wilson stations. However, as mentioned above, the final MATS rule includes only filterable particulate emissions requirements and therefore, we would no longer recommend ESP upgrades at the Coleman and Wilson stations. In the addendum prepared to address the final MATS requirements, S&L recommends testing ESP performance while injecting activated carbon and dry sorbent injection at Coleman Units 1, 2, and 3, Wilson Unit 1, and Green Units 1 and 2 to determine whether ESP upgrades will be required to maintain filterable particulate emissions below the MATS requirements.

Q. What options were considered by S&L for compliance with the CSAPR and NAAQS requirements that were not recommended for implementation?

A. The final study report attached as Exhibit DePriest-2 describes the commercially available technologies that were considered for compliance with the various regulatory requirements. I will describe below some of the noteworthy technologies or combinations of technologies that were considered but not chosen as the most cost effective.

To reduce SO_2 emissions as part of a CSAPR compliance strategy, the following technologies were among those considered, but not recommended by S&L:

1. Wet FGD additives such as dibasic acid to improve SO_2 removal rates at the existing wet FGD control systems at Coleman Units 1, 2, and 3.
2. In an addendum to the S&L report, switching from bituminous coal to subbituminous Power River Basin ("PRB") coal was considered, but not recommended, for the HMP&L, Wilson, and Green stations to reduce NO_X and SO_2 emissions.
3. To reduce nitrogen oxide emissions as part of a CSAPR compliance strategy, Selective Non-Catalytic Reduction ("SNCR") technology was considered, but was not recommended by S&L.

Q. Please explain the reason these options were not recommended.

A. The use of performance enhancing additives in wet FGD systems has been used to achieve modest improvements in SO_2 capture performance. However, the incremental improvement achievable at Coleman was not as cost effective as the incremental improvement achievable with the new FGD system at Wilson. In addition, the SO_2 reduction from the new FGD at Wilson, the HMP&L FGD improvements, and the Reid natural gas conversion satisfied the requirements of CSAPR at a lower cost than achievable with the additives at Coleman.

Switching from the current bituminous coal to a PRB coal was not recommended as a compliance option for CSAPR because PRB coal has a significantly higher cost, on a dollar-per-Btu basis, and the PRB option resulted in a significantly higher NPV as compared to the recommended compliance strategy. This subject is described in an addendum to the report and included as Exhibit DePriest-4.

The SNCR strategy was similar in NPV to the SCR strategy but was not recommended for a variety of factors. In part, SNCR was not recommended because of the high costs associated with the urea reagent, which is consumed at a high rate compared to the modest NOx removal capability. In addition, SNCR systems can have high ammonia slip levels, which can lead to increased air heater fouling due to ammonium bisulfate formation. Finally, SNCR systems have a slow response to load shifts because they are very dependent upon operating in the optimal temperature range.

Q. What options were considered by S&L for compliance with the MATS Rule that were not recommended for implementation?

A. The final study report attached as Exhibit DePriest-2 describes the commercially available technologies that were considered for compliance with the various regulatory requirements. Below, I describe some of the noteworthy technologies or combinations of technologies that were considered but not chosen as the most cost effective.

To reduce particulate emissions as part of a MATS compliance strategy, fabric filters or baghouses were considered, but not recommended by S&L.

Also, to reduce mercury emissions as part of a MATS compliance strategy, halogen fuel additives were considered, but not recommended by S&L.

Q. Please explain the reason these options were not recommended.

A. Big Rivers emissions test data show that the final MATS filterable particulate emissions requirements are being met with the existing electrostatic precipitators. While some ESP upgrades may be required to handle the additional particulate loading due to the activated carbon and sorbent injection that will be used for mercury control, the capital cost for new fabric filters was significantly higher than upgrades to the existing electrostatic precipitators and could not be justified.

Halogen fuel additives are used to increase the oxidation of mercury in the flue gas since oxidized mercury is more readily removed in wet FGD control systems. Fuel additives are generally not recommended by S&L for units firing bituminous coals, such as the Big Rivers facilities, because bituminous coals generally have relatively high halogen concentrations that inherently support mercury oxidation and mercury capture in the FGD control system. Our expectation is that mercury oxidation level and subsequent capture in the FGD system is at its optimum level without the use of additives to the fuel or the flue gas. Note that this "optimum" level of mercury capture and retention in the FGD system will not be adequate to meet the regulatory requirements and thus the need for activated carbon injection.

Q. What technologies are not included in Big Rivers' 2012 Plan that were recommended by S&L?

A. Advanced low NO_X burners were originally recommended by S&L for installation on Coleman Units 1, 2 and 3 for reasons discussed earlier, but Big Rivers elected not to implement this technology. Because CSAPR is a cap-and-trade program, Big Rivers will have the option of purchasing additional NO_X compliance allowances in lieu of using low NO_X burners, if needed, for CSAPR compliance.

Q. What other issues did S&L consider that are not included in this application, if any?

A. S&L considered the potential impacts to the Big Rivers generating stations from the United States Environmental Protection Agency's ("EPA") proposed rules for implementing Section 316(b) of the Clean Water Act, EPA's proposed regulation for the management of Coal Combustion Residuals ("CCR"), and the potential for new wastewater effluent guidelines that may be issued by EPA in the future.

V. CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY

Q. What are the timing considerations associated with the construction of the projects included in the 2012 Plan?

A. The implementation timeline for the strategy recommended to comply with CSAPR follows Big Rivers' planned unit outage schedules for the facilities, and is tailored to minimize periods when Big Rivers would need to purchase additional CSAPR allowances to meet its CSAPR allowance requirements. For technologies recommended to comply with MATS, the implementation timeline is governed by the 2015 compliance deadline established by the regulation.

Q Can Big Rivers complete construction of the projects you have described in time to use the facilities to meet the compliance requirements in the 2012 Plan?

A. Big Rivers will not be able to complete construction of its FGD project at Wilson or its SCR project at Green Unit 2 in time to meet current CSAPR compliance requirements for SO_2 and NO_X in 2014. Big Rivers will need to either purchase additional NO_X credits, as permitted by CSAPR, or curtail generation to offset NO_X emissions in excess of its allowance allocations until the Green SCR is complete. If Big Rivers does not have sufficient quantities of SO_2 allowances banked, it will need to either purchase allowances or curtail generation to achieve compliance until the Wilson FGD project is completed.

VI. CONCLUSION

Q. What are your conclusions and recommendations to the Commission in this proceeding?

A. Based on the environmental regulation review, technology screening and cost estimating that S&L has performed for Big Rivers, and based on the data input and assumptions considered as outlined in Exhibit DePriest-2, the recommendations provided by S&L will allow Big Rivers to meet the requirements of the existing and proposed regulations in the most cost effective manner. The facilities and actions recommended in the study are necessary to comply with the environmental laws and regulations.

Q. Does this conclude your testimony?

A. Yes.

BIG RIVERS ELECTRIC CORPORATION

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

CASE NO. 2012-00063

VERIFICATION

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

William DePriest

William DePriest

STATE OF ILLINOIS)
COUNTY OF COOK)

SUBSCRIBED AND SWORN TO before me by William DePriest on this the 29th day of March, 2012.

Tira L. Seals

Notary Public,
State of Illinois
My Commission Expires May 4, 2015

OFFICIAL SEAL
TIRA L SEALS
NOTARY PUBLIC - STATE OF ILLINOIS
MY COMMISSION EXPIRES:05/04/15

Case No. 2012-00063
Exhibit DePriest-1 – DePriest Professional Summary

WILLIAM DEPRIEST
Senior Vice President and Director
Environmental Services
Fossil Power Technologies

EDUCATION

Michigan Technological University - B. S. Chemical Engineering - 1972

REGISTRATION

Professional Engineer - Wisconsin

EXPERTISE

Air toxic control technologies
Combined NO_X and SO_2 control technologies
Coal gasification and its integration with combustion turbines and combined cycles (IGCC)
Condition assessment of emission control systems and equipment
Combustion and post-combustion NO_X control technologies (LNB, OFA, SNCR, SCR, etc.)
ESP and FF particulate control technologies
Emission control byproduct development (gypsum, fertilizer, etc.)
Emission control technologies
Flue gas desulfurization (FGD)
Repowering with advanced combustion technologies

RESPONSIBILITIES

As Senior Vice President and Director of Environmental Services, Mr. DePriest is responsible for ensuring that all fossil-related projects are fully supported with the appropriate environmental related expertise for successful execution of the project. He is also responsible for maintaining current expertise in environmental technologies for fossil fired power facilities including PC, CFB, and IGCC plants.

EXPERIENCE

Mr. DePriest has more than 30 years of experience dedicated to the application of emission control technology in the utility industry. This expertise primarily focuses on the areas of NO_X, SO_2, and particulate control with expanding expertise in air toxin and CO_2 control.

As Sr. Vice President and Director of Environmental Services, Mr. DePriest has directed the application of both combustion-based and post-combustion-based NO_x control technologies on a variety of coal and gas fired utility plants representing well over 30,000 MW of capacity. These NO_X control technologies covered the spectrum of commercially available technologies including low-NO_X burners (LNBs), over-fire air (OFA) systems, neural networks, selective non-catalytic reduction (SNCR), selective catalytic reduction (SCR), reburning, and combinations of these.

In addition, Mr. DePriest has directed, or is currently directing, the application of flue gas desulfurization (FGD) technology on 20 recent retrofit FGD projects representing over 12,000 MW of coal-fired generating capacity.

Mr. DePriest has also directed S&L's IGCC Program through work with utility clients, EPRI, and permitting agencies.

Mr. DePriest is a recognized expert in the industry on environmental control technology and he has written and published extensively on the subject.

Before joining Sargent & Lundy, he was the environmental product manager for a major equipment supplier to the utility industry. He had responsibility for the company's environmental product lines, including, NO_X reduction systems, FGD systems (wet and dry), precipitators and baghouses. In this capacity he managed the functional engineering on more than 10 wet and dry FGD systems. This functional engineering involved equipment sizing, specifications, material of construction, and overall process design from the air heater outlet to the stack. Also included was similar design work on auxiliaries, such as reagent preparation systems and waste dewatering and disposal systems. Two of these systems produce gypsum as a byproduct, which is currently being used by leading wallboard manufacturers.

Mr. DePriest managed a field process-engineering group in conjunction with this design work, which started up and serviced utility emission control systems. He also supervised the operation of two emission control pilot projects operated at coal-fired utility sites. One used magnesium-promoted lime as the reagent and the other used waste soda liquor. Information generated from these pilots was then used in the process design of full-scale FGD systems.

His specific experience over his 20 years with Sargent & Lundy includes:

TESTIMONY SUPPORT

I have provided testimony and/or depositions regarding similar regulatory issues for the following clients :

- **Indianapolis Power & Light ("IPL"),** Indiana Utility Regulatory Commission Cause No. 42170, regarding IPL's request for approval of a Certificate of Public Convenience and Necessity ("CPCN") to construct various Clean Coal Technology ("CCT") projects to address the NOx State Implementation Plan ("SIP") call.
- **Indianapolis Power & Light ("IPL"),** Indiana Utility Regulatory Commission Cause No. 42700, regarding IPL's request for modification of it Certificate of Public Convenience and

Necessity ("CPCN") issued in Cause No. 42170 to construct two additional Clean Coal Technology ("CCT") projects (the first step of IPL's Multi-Pollutant Plan, hereinafter referred to as "MPP-1").

- **Reliant Energy** – Petition of Reliant Energy, Inc. for Approval of Environmental Cleanup Costs Plan in the State of Texas State Office of Administrative Hearing (SOAH) Docket No. 473-02-0473, PUC Docket No. 24835.
- **Texas Genco & Centerpoint Energy** – Application of Texas Genco, LP and Centerpoint Energy Houston Electric, LLC, and Texas Genco, LP to determine stranded costs and other True-up balances pursuant to the Public Utilities Regulatory Policy Act ("PURPA") 39.262 PUC Docket No. 29526.
- **Mid America Energy** – Their "Multi-Pollutant" Environmental Plan in the State of Iowa, Iowa Dept. of Commerce before the Iowa Utilities Board. Docket No. EPB-02-156.

COAL GASIFICATION EXPERIENCE (IGCC)

- Minnesota Power

  - Advanced integrated gasification/pressurized fluid bed combustion.

    Project Manager. Development of an advanced integrated gasification/pressurized fluid bed combustion conceptual design with a major boiler manufacturer. Project included hot/pressurized particulate and sulfur clean-up processes as well as advanced combustion turbine technology. (1992 to 1994)

- Electric Power Research Institute

  - PRENFLO-based integrated-gasification combined cycle (IGCC) study.

    Project Manager. Study investigating the advantages and disadvantages of integration of the air separation plant with the combustion turbine on a PRENFLO-based IGCC power plant. Study also included the use of advanced high-temperature particulate control of the raw syngas prior to desulfurization and combustion. (1989 to 1993)

  - Advanced IGCC concepts study.

    Project Engineer. Study of advanced concepts of IGCC power facilities. Study quantified the heat rate improvements expected from employing advanced cycle designs and the related costs for a nominal 400-MW plant. (1987 to 1989)

- IGCC Site Selection

  - Under Mr. DePriest's direction, S&L has assisted utilities with the selection of sites for IGCC deployment in Indiana, Virginia, Oklahoma, Kentucky, Louisiana, Arkansas, Ohio, Tennessee, West Virginia, Virginia and Indiana.

- IGCC Permit Application and Support

  - Under Mr. DePriest's direction, S&L has written permit applications and/or performed BACT analysis for IGCC deployment in IL, MT, NT, ND, WY, and MI.

RECENT EMISSION CONTROL PROJECT EXPERIENCE

- SO_2 Control Projects

  20 FGD projects representing over 12,000 MW of coal-fired capacity. Included in this experience are the following examples of utility FGD programs:

  - Cinergy
  - Kentucky Utilities (LGE)
  - American Electric Power
  - Santee Cooper

- Strategic Planning Projects

  Strategic Compliance (NO_X, SO_X, particulate and Hg) Plan Development for 36 different utility systems representing over 40,000 MW of capacity. Included in this experience are the following examples of utility system-wide emission compliance plans:

  - Ameren UE/Ameren CIPS
  - Associated Electric
  - Cinergy
  - MidAmerican
  - Reliant Energy
  - TXU

- NO_X Control Projects

  Over 30 LNB projects representing over 6,000 MW of capacity, 30 SCR retrofit design projects for coal fired units representing 16,000 MW of capacity, and 13 gas-fired units representing over 8000 MW of capacity. Some recent examples are:

- Dynegy (LNB, OFA, SCR, ESP)
- Reliant Energy (LNB, OFA, SCR)
- Santee Cooper (SCR, FGD)
- Cinergy (LNB, SCR, FGD)

• Electric Power Research Institute
  - Development of advanced retrofit FGD concepts for compliance with the 1990 Clean Air Act Amendments. (1991 to 1992)
  - Development of the Clean Air Technology (CAT) computer workstation to identify least-cost SO_2 and NO_X compliance strategies. (1991 to 1992)
  - Project Manager: Study involves the screening of over 60 advanced combined NO_X/SO_2 processes, selecting the eight most promising for utility application, performing conceptual design and cost estimates, and identifying research and development requirements to bring to commercial viability. (1988 to 1992)
  - Project Manager. Study of FGD systems in cycling service that investigated the effect that various types of unit cycling will have on six different generic types of FGD processes. Guidelines for design and operation resulted from the study. (1988 to 1991)
  - Project Consultant. Retrofit FGD design improvement study to identify and investigate design improvements to reduce the cost of retrofitting FGD to utility power plants. (1988 to 1990)

Some specific examples of Mr. DePriest's work with the control of SO_2 while with Sargent & Lundy follow:

As Manager of Environmental Services, Mr. DePriest has managed the process design on all of S&L's 20 FGD projects since 1990. The following five FGD retrofit projects are examples of these projects:

- Kentucky Utilities: Ghent 1, coal, 550 MW
- Owensboro Municipal Utilities: Elmer Smith 1 and 2, coal, 416 MW total
- TXU: Monticello 3, coal, 750 MW and Martin Lake 1-3, coal, 720 MW each
- Cinergy: Gibson 4, coal, 650 MW
- Santee Cooper Winyah 1 and 2, coal, 320 MW each

The following are other examples of Mr. DePriest's experience with SO_2 control on coal-fired power plants:

- Owensboro Municipal Utilities

  - Elmer Smith 1 and 2, coal, 416 MW total

    Emission Control Consultant. Acid rain legislation compliance study. (1989 to 1990)

- Ameren

  - Systemwide coal-fired units.

    Project Manager. System Strategic NO_X and SO_2 compliance planning study. (1989 to 1990)

- Northern Indiana Public Service Company

  - Bailly 7 and 8, coal, 616 MW total

    Provided expert advice on the retrofit of a Mitsubishi wet FGD system (Pure Air) to the combined flue gases from these two units. (1988 to 1989)

- Central Louisiana Electric Company, Inc.

  - Dolet Hills 1, lignite, 719 MW

    Provided expert advice on performance test methodologies, interpretations of testing results, and comparison of results with contract guarantees. Systems tested included the electrostatic precipitator and FGD systems. (1987 to 1989)

- TXU

  - Sandow 4, lignite, 591 MW

    Designed process to recover di-basic acid from the spent slurry leaving a limestone-based FGD system. This facilitated recycling the di-basic acid for reduced plant operating expense. (1986 to 1987)

- Southwestern Electric Power Company

  - Pirkey 1, lignite, 720 MW

    Developed a performance test specification and methodologies for contract guarantee testing of the air heaters, precipitators, and FGD system. Interpreted test results and system suppliers' compliance with guarantees. Provided general process expertise for solving performance problems that were causing load reductions to maintain compliance with emission regulations. (1985 to 1986)

OTHER FLUE GAS DESULFURIZATION PROJECT EXPERIENCE PRIOR TO JOINING SARGENT & LUNDY

- Pacific Power & Light Company/Idaho Power Company

  - Jim Bridger 2, coal, 508 MW

    Managed the process design and functional engineering of the backfitted sodium-based FGD system. Managed the one-year/$1,000,000 pilot project at the station, the results of which were used in the full-scale equipment design. (1983 to 1985)

- Lakeland Department of Electric & Water Utilities

  - McIntosh 3; coal, oil, and municipal refuse; 350 MW

    Managed the process design and functional engineering of the FGD system on this multi-fueled power plant. Plant typically operates on high-sulfur augmented with refuse. (1978 to 1982)

- San Miguel Electric Cooperative

  - San Miguel 1, lignite, 400 MW
    (1976 to 1982)

- Sikeston, Board of Municipal Utilities

  - Sikeston 1, coal, 235 MW
    (1978 to 1981)

- South Carolina Public Service Authority/Santee Cooper

  - Winyah 2 and 3, coal, 270 MW each
    (1975 to 1980)

- Southern Illinois Power Cooperative

  - Marion 4, coal, 173 MW

    Process Design Engineer and Supervisor. Control and instrumentation systems design and supervisor of field process engineering and startup services for limestone-based FGD systems. (1976 to 1978)

- Allegheny Power System/Monongahela Power Company

  - Pleasants 1 and 2, coal, 626 MW each

    Process Design Engineer and Supervisor. Control and instrumentation systems design as well as supervisor of field process engineering and startup services for limestone-based FGD system. Designed a 5,000 cfm pilot to simulate the full-size unit and develop data for use in its ultimate design. (1977 to 1980)

- Kansas City Power & Light Company/Kansas Gas and Electric Company

  - LaCygne 1, coal, 848 MW

    Field Service Engineer. Pioneering (5% to 7%) limestone-based FGD system. (1973 to 1975)

- Commonwealth Edison Company

  - Will County 1, coal, 188 MW

    Field Service Engineer. Company's first FGD system, which was also a retrofit application. (1972 to 1973)

NO_X CONTROL EXPERIENCE

Mr. DePriest has been the Environmental Services Director both for combustion-based and post-combustion-based NO_X control projects.

Following are example utilities where Mr. DePriest has experience with retrofit of LNBs and overfire air (OFA) systems:

- Reliant Energy (Texas Genco)
- Owensboro Municiple Utilities
- Mid American

Following are example utilities where Mr. DePriest has experience with the design of post-combustion SCR projects:

- Dynegy
- Reliant Energy (Texas Genco)
- Santee Cooper

EMISSION CONTROL BYPRODUCT DEVELOPMENT

- Owensboro Municipal Utilities

  - Elmer Smith 1 and 2, coal, 450 MW

    Conversion of forced oxidation system to commercial grade gypsum production for wallboard use. (1994)

- Houston Lighting & Power Company

  - Limestone 1 and 2, lignite, 809 MW each

    Performed a detailed technical and economic study for the conversion of the existing FGD system to forced oxidation and the production of a marketable gypsum byproduct. (1986)

- Applied Energy Services

  - Deepwater 1, petroleum coke, 135 MW

    Manager. Process design and functional engineering for the FGD, wet electrostatic precipitator, and pressurized forced oxidation system. Wet precipitator removed sulfuric acid mist resulting from firing a high vanadium petroleum coke. The pressurized oxidation system produced a high-quality wallboard gypsum. Managed field startup service activities. (1983 to 1985)

- Grand Haven Board of Light & Power

  - J. B. Sims 3, coal, 65 MW

    Managed the process design and functional engineering of lime-based FGD system. Design included a unique concept for force oxidizing the sulfite-rich slurry to produce a marketed gypsum product (for wallboard) while enhancing the SO_2 removal capabilities of the system. Managed the field startup and field process engineering activities. (1980 to 1984)

CONDITION ASSESSMENT

- Louisville Gas & Electric Company

  - Cane Run 4-6, coal, 645 MW total.

    Project Engineer for condition assessment of FGD equipment. (1991)

- Duquesne Light Company
    - Elrama 1-4, coal, 425 MW

      Project engineer on the FGD portion of the plant condition assessment study to assess operation to the year 2007. (1987 to 1988)

MEMBERSHIPS

American Society of Mechanical Engineers

Committee PTC-40, Performance Test Code on Flue Gas Desulfurization

Environmental Control Division FGD Subcommittee (chairman)

Environmental Control Division Economic Evaluation Committee

Air & Waste Management Association

PUBLICATIONS

"Technologies and Emission Allowances", Emission Management Association 8th Annual Spring Meeting, New Orleans, May 2004

"Condensable Particulate Matter Emission Sources and Control in Coal-Fired Power Plants", EPRI-DOE-EPA-AWMA Combined Power Plant Air Pollution Control Mega Symposium, Washington, DC, August 2004

"Economics of Lime and Limestone for Control of Sulfur Dioxide", EPRI-DOE-EPA-AWMA Combined Power Plant Air Pollution Control Mega Symposium, Washington, DC, May 2003

"Prospects for Lime in Future FGD Markets", National Lime Association Meeting, Santa Monica, CA, February 2003

"Mercury Speciation and Impact of Current Controls: An Interpretation of the ICR Database", CoalGen Conference, July 2001

"Reliant Energy's NO_X Reduction Program for their Houston Area Generating Facilities", Technology Selection and Design Challenges" EPA-DOE-EPRI Power Plant Air Pollution Control Symposium, Chicago, August 2001

"Development and Maturing of Environmental Control Technologies in the Power Industry", Emissions Trading: Environmental Policy's New Approach, Copyright 2000 University of Illinois at Chicago

"Optimizing SCR Reactor Design for Future Operating Flexibility" ICAC FORUM 2000 on "Cutting NO_X Emissions", March 2000

"Control Technology Selection and Application to Meet NO_X Compliance", Plant Design and Operating Committee Meeting, Galveston, TX, 2000

"Short-Term NO_X Emission Reductions with Combustion Modifications on Low to Medium Sulfur Coal-fired Cyclone Boilers", EPRI-DOE-EPA Combined Utility Air Pollutant Control Symposium, Washington, D.C., 1997

"Revisiting Your NO_X Compliance Strategy: The Impact of Title IV - Phase II, Title I-OTAG, and Proposed New NAAQS", 59th American Power Conference, 1997, Chicago, Illinois

"Impacts of Title III and IV of the Clean Air Act and the Revised NAAQS on Particulate Control Strategies for Year 2000 and Beyond", International Joint Power Generation Conference, Denver, 1997

"Cost Effective Deployment of Technology to Meet Air Emission Compliance in Developing Regulatory Environment" PowerGen Asia Conference, New Delhi, India, 1996

"Options for Repowering the Utility Industry" PowerGen Conference, Anaheim, California 1995

"Compliance and Competition: Obstacle or Opportunity," 1995 Sargent & Lundy Fossil Engineering Conference, Chicago, Illinois, 1995

"Key Issues for Low Cost FGD Installation," Energy and Environment: Transitions in East Central Europe, Prague, 1994

"Cost-Effective Retrofits for Emission Controls," Energy and Environment: Transitions in East Central Europe, Prague, 1994

"CO_2 and Air Toxins: Planning for Future Regulatory Uncertainty," 1994 International Joint Power Generation Conference, Phoenix, Arizona, 1994 (et al.)

"Clean Air Technology (CAT) Workstation: Case Study" 1993 SO_2 Symposium, Boston, Massachusetts, 1993

"Flue Gas Desulfurization Cycling Guidelines" 1993 SO_2 Symposium, Boston, Massachusetts, 1993

"Novel Integration Concepts for GCC Power Plants," Fifth International Power Generation Conference, Orlando, Florida, 1992

"Clean Air Technology Workstation," 1991 SO_2 Control Conference, Washington, D.C., 1991

"Comparison of Coal Gasification Combined-Cycle Integration Concepts," EPRI 10th Annual Conference on Coal Gasification Power Plants, San Francisco, California, 1991

"Engineering Evaluation of Combined NO_x/SO_2 Controls for Utility Application," 1991 SO_2 Control Conference, Washington, D.C., 1991"Acid Rain Compliance Analysis Evaluating Technology Options Within a Market-Based Regulatory Scheme," IJPGC, Boston, Massachusetts, 1990

"Combining SO_2 and NO_x Control Technologies as a Strategy for Environmental Compliance," Clean Power from Coal Conference, Brussels, Belgium, 1990

"Design and Operation of FGD Systems for Cycling Service," EPA/EPRI 1990 SO_2 Control Symposium, New Orleans, Louisiana, 1990

"Engineering Evaluation of Combined NO_x/SO_2 Removal Processes: 2nd Interim Report," EPA/EPRI 1990 SO_2 Control Symposium, New Orleans, Louisiana, 1990

"Integrated Coal Gasification Combined Cycle: Is It Competitive With a Pulverized Coal-Fired Boiler for Power Generation?" Sargent & Lundy Engineering Conference, Chicago, Dallas, and Houston, Texas, 1990

"A Second Look at Cogeneration in a Coke Oven Plant," Annual Association of Iron and Steel Engineers Convention, Pittsburgh, Pennsylvania, 1989

"Conceptual Design and Economic Evaluation of a Coal Dechlorination Plant," EPRI First International Conference on Chlorine in Coal, Chicago, Illinois, 1989

"Engineering Evaluation of Combined NO_X/SO_2 Removal Processes: Interim Report" Joint Symposium on Stationary Combustion NO_X Control, San Francisco, California, 1989

"Review of Potential Cycle Improvements for an IGCC Plant" 8th EPRI Coal Gasification Conference, Palo Alto, California, 1988

"Flue Gas Desulfurization: Growing Pains/Proven Remedies," Sargent & Lundy Engineering Conference, Dallas, Texas, 1987

"Gypsum - An FGD Byproduct," Coal Technology '85, Pittsburgh, Pennsylvania, 1985

"Wet Lime FGD System Design and Early Operating Experience at the City of Grand Haven, Michigan, Board of Light and Power's J. B. Sims Unit 3," National Lime Association, Denver, Colorado, 1983

"Dry SO_2 System Design and Early Operation Experience at Basin Electric's Laramie River Station," 32nd Canadian Chemical Engineering Conference, Vancouver, British Columbia, Canada, and the Joint Power Conference, Denver, Colorado, 1982

"Wet SO_2 Removal Operating Experience at Cincinnati Gas & Electric Company's East Bend Station," American Power Conference, Chicago, Illinois, 1982

"Three Years of SO_2 Control Experience at Winyah Station, South Carolina Public Service Authority," American Power Conference, Chicago, Illinois, 1981

"Lime and Limestone Wet Scrubber Performance," Third International Coal Utilization Exhibition and Conference, Houston, Texas, 1980

Case No. 2012-00063
Exhibit DePriest-2 – Sargent & Lundy Study

Big Rivers Electrical Corporation Environmental Compliance Study

Prepared by: Sargent & Lundy, LLC
Revision: Final
Date: February 13th, 2012

Sargent & Lundy LLC

55 East Monroe Street • Chicago, IL 60603 USA • 312-269-2000

Green, Henderson, Reid, Coleman & Wilson Stations

Environmental Compliance Study

Prepared for
Big Rivers Electric Corporation

SL-010881
February 2012
Project 12845-001

55 East Monroe Street

Sargent & Lundy LLC

Chicago, IL 60603-5780 USA

LEGAL NOTICE

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GLOSSARY OF TERMS

ACI - Activated Carbon Injection: A mercury reduction process system that involves the injection of a very fine dry powdered form of carbon into the flue gas stream of coal burning power plants.

AFUDC – Allowance for Funds Used During Construction: Interest that occurs on capital project loans during the construction period.

BACT – Best Available Control Technology: BACT is a pollution control standard detailed in the Clean Air Act in which the Environmental Protection Agency (EPA) determines what air pollution control technology should be applied to control a specific pollutant to a specified limit.

BREC – Big Rivers Electric Corporation

BTA – Best technology available

CAIR – Clean Air Interstate Rule: A rule issued by the EPA in 2005 that was intended to implement the Clean Air Act requirements concerning the transport of air pollutants across state boundaries, and assist downwind states to attain and maintain the National Ambient Air Quality Standards for ozone and fine particulate matter. The rule was vacated by the U.S. Court of Appeals in 2008. See CATR – Clean Air Transport Rule.

CCR - Coal Combustion Residuals: Byproducts of the coal combustion process, including but not limited to fly ash, bottom ash, and wet flue gas desulfurization waste streams.

Cl – Chloride: Constituent of Coal.

CO - Carbon Monoxide: A flue gas pollutant.

CPM – Condensable Particulate Matter: See PM.

CSAPR – Cross-State Air Pollution Rule: Rule issued by the EPA that replaces the previously issued 2005 Clean Air Interstate Rule.

DSI - Dry Sorbent Injection: A process system that involves the injection of a dry sorbent into the flue gas stream of coal burning power plants. May be used for reduction of sulfur trioxide (SO_3) or other acid gases.

EGU MACT - Electric Generating Utility Maximum Achievable Control Technology: Proposed rule issued in March 2011 by the EPA setting emissions standards for certain pollutants, including mercury, particulate matter, acid gases, and several others. MACT standards for air pollution require a maximum reduction of hazardous emissions, considering cost and feasibility, and are set based on a review of existing sources.

EPA – United States Environmental Protection Agency

GLOSSARY OF TERMS (cont.)

ESP - Electrostatic Precipitator: A particulate matter control device installed in boiler flue gas systems.

FGD – Flue gas desulfurization

FPM – Filterable Particulate Matter: See PM.

fps – Feet per Second: Unit of measure.

HAP – Hazardous Air Pollutants: Hazardous emissions from power plants or other sources.

HCl – Hydrochloric Acid: An acid byproduct of coal combustion.

Hg – Mercury: Constituent of certain coals.

ICR - Information Collection Request: A request by the EPA for operating data from electric generating unit operators. Used to support the development of emission limits.

IM&E - Impingement Mortality and Entrainment: Injury, death, or entrainment of fish and other organisms. See 316 (b).

KPDES - Kentucky Pollutant Discharge Elimination System

lb/MMBtu - Pounds per Million British Thermal Units: A unit of measure.

lb/TBtu – Pounds per Trillion British Thermal Units: A unit of measure.

LNB – Low-NO_X burner

LNCFS - Low NO_X Concentric Firing System: A proprietary combustion system arrangement for Alstom (formerly Combustion Engineering) cyclone boilers. The equipment may include low NO_X burners, separated overfire air systems (see OFA definition, as well as other technologies depending on the generation of LNCFS system being considered. Currently there are four generations of this system that have been developed (LNCFS I, II, III, and IV).

MACT – Maximum Achievable Control Technology

MGD – Million gallons per day

MMBtu – Million British Thermal Units: A unit of measure.

NAAQS – National Ambient Air Quality Standards: Standard developed by the EPA to set the required levels of air quality.

GLOSSARY OF TERMS (cont.)

NO_X – Nitrogen Oxides

NPV – Net Present Value: A present value is the value now of a stream of future cash flows, negative or positive, including initial costs of purchasing an asset.

O&M - Operating and Maintenance

OFA – Overfire Air: Also SOFA or Separated Overfire Air System. Various methods of staging combustion in a boiler for enhanced NO_X reductions.

ORSANCO – Ohio River Sanitation Commission: Discharges to the Ohio River are also regulated by ORSANCO. It sets Pollution Control Standards for industrial & municipal waste water discharges to the Ohio River.

pH: A measure of the acidity or basicity of an aqueous solution.

PM – Particulate Matter: Condensable or filterable particulate matter in flue gas stream. PM2.5 refers to fine particulate matter with diameters less than 2.5 micrometers; PM10 to matter with diameters less than 10 micrometers.

RCRA – Resource Conservation and Recovery Act: The RCRA Act gives the EPA the authority to control hazardous waste from the "cradle-to-grave." This includes the generation, transportation, treatment, storage, and disposal of hazardous waste. Sets the framework for management of non-hazardous wastes.

ROFA – Rotating overfire air

S&L – Sargent & Lundy, LLC

SCR - Selective Catalytic Reduction: A NO_X reduction system that uses a reagent such as ammonia in conjunction with a catalyst reactor to convert NO_X into harmless nitrogen.

Sebree Generating Station: Encompasses the Robert D. Green Station, Robert A. Reid Station, and the HMP&L Station.

SNCR - Selective Non-Catalytic Reduction: A NO_X reduction process technology that involves the injection of a NO_X reduction agent such as ammonia or urea solution into a boiler.

SO_2 – Sulfur Dioxide

SO_3 – Sulfur Trioxide

SSC – Submerged Scraper Conveyor: A dry bottom ash handling technology.

GLOSSARY OF TERMS (cont.)

TBtu – Trillion British Thermal Units: A unit of measure.

Title V: Operating permits for air pollution sources are issued under Title V of the EPA's Clean Air Act

TPM – Total Particulate Matter

tpy – Tons per year

WFGD - Wet Flue Gas Desulfurization: A wet scrubbing process for removing SO_2 from flue gas streams that uses an alkaline reagent introduced as a fine spray in an absorber vessel.

316(b) Regulations: Environmental regulations being developed by the EPA that require the cooling water intake structures to reflect the best technology available for minimizing adverse environmental impact. Adverse environmental impacts include the impinging of fish and other organisms on cooling system intake screens or pumping equipment, as well as the entrainment of fish and other organisms in the cooling systems. See Impingement Mortality and Entrainment (IM&E).

EXECUTIVE SUMMARY

Environmental regulations currently in place and being actively developed by the U.S. Environmental Protection Agency (EPA) and the U.S. Congress are expected to require additional reductions of several air pollutants for many electric utilities. These include sulfur dioxide (SO_2) and nitrogen oxides (NO_X), which are addressed under the Cross-State Air Pollution Rule (CSAPR) regulations, and total particulate matter (TPM), mercury (Hg), and hydrochloric acid (HCl), which are addressed under the EPA's proposed Electric Generating Utility Maximum Achievable Control Technology (EGU MACT) regulations. Additional EPA regulations are proposed to reduce impingement mortality and entrainment of fish, eggs, larvae, and other aquatic organisms that come in contact with a station's cooling water intake system. (Since this study was completed, the EGU MACT was replaced the Mercury and Air Toxins Standard (MATS). This report has not been updated to reflect the new MATS rule.)

The EPA is also proposing alternative approaches for regulating coal combustion residual (CCR) waste products. It is likely that CCR regulatory requirements for pond modification and operation, along with the pending wastewater discharge effluent guideline requirements, will make continued operation of the dewatering ponds impractical. Wastewater discharge effluent guidelines being proposed by the EPA will likely also impact the station's ability to discharge large volumes of ash sluice water to the environment, due to limits on total dissolved solids, metals, pH and other parameters, further necessitating the dry bottom ash conversions.

Phase I of this study provides a thorough assessment of the various expected future regulations as they apply to BREC. Phase II of this study draws on the conclusions developed in the Phase I regulatory assessment, and provides an evaluation of possible compliance strategies, using existing technologies, new technologies, or a combination of technologies. Phase III screens the viable technology selections based on an evaluation using order of magnitude capital and O&M costs. Where the screening results in multiple compliance strategies being proposed, a net present value (NPV) analysis is used to provide the optimal selection. The impact of any changes between the proposed or predicted rules considered in this study and the final rules that are promulgated should be evaluated and the conclusions adjusted accordingly.

The results are summarized along with the associated net present value (NPV). Currently planned O&M improvements are not considered in the costs described in this evaluation since S&L understands them to be already accounted for in the operating budget for current or upcoming fiscal years.

SULFUR DIOXIDE (SO_2)

In order to achieve compliance with their 2012 and 2014 CSAPR allocations, BREC will need to reduce their current SO_2 fleet-wide emissions from 27,286 tpy to 26,478 tpy in 2012–2013 and to 13,643 tpy for 2014 and beyond. Although potential reductions are speculative at this time, additional allocation reductions of 20% may follow the CSAPR regulations as part of National Ambient Air Quality Standards (NAAQS), which will require an even greater reduction in emission to meet the potential 10,914-tpy allocation in 2016–2018. To meet the forthcoming CSAPR emission allocations and the potential NAAQS reductions, BREC will need to make modifications to reduce emissions. A summary of the baseline emissions data, recommended modifications for CSAPR and NAAQS compliance, expected emission reductions, and the estimated NPV associated with the technology selections is provided below.

Table ES-1 — SO_2 CSAPR and NAAQS Compliance Strategy

Unit	Baseline SO_2 Emissions (tpy)	Current Annual SO_2 Emission Rate (lb/MMBtu)	Technology Selection	Estimated New SO_2 Emissions (tpy)	Estimated New Annual SO_2 Emission Rate (lb/MMBtu)	Net Present Value at Baseline Credit Value (2011$ Million)
Coleman Unit C01	1,473	0.250	None**	1,473	0.250	N/A
Coleman Unit C02	1,473	0.250	None**	1,473	0.250	N/A
Coleman Unit C03	1,571	0.250	None**	1,571	0.250	N/A
Wilson Unit W01	9,438	0.510	New Tower Scrubber - 99% removal	1,049	0.057	$82.5
Green Unit G01	1,873	0.186	None	1,873	0.186	N/A
Green Unit G02	1,414	0.139	None	1,414	0.139	N/A
HMP&L Unit H01	2,227	0.347	Run both pumps & spray levels, install 3rd pump as	788	0.123	-$2.1
HMP&L Unit H02	2,745	0.415	Run both pumps & spray levels, install 3rd pump as	835	0.126	-$2.1
Reid Unit R01	5,066	4.522	Natural Gas with Existing Burners	1	0.001	$8.9
Reid Unit RT	5	0.117	None	5	0.117	N/A
Fleet Total	**27,286**	**0.384**	**N/A**	**10,482**	**0.148**	**$87.2**

**Note SO2 emissions in this scenario have been adjusted to reflect data received from BREC confirming that the Coleman FGD is capable of producing emission rates of 0.25lb/MMBtu and reaching removal rates of approximately 95%.

UNIT 1 NITROGEN OXIDES

To achieve compliance with their 2012 and 2014 CSAPR NO_X allocations, BREC will need to reduce their current fleet-wide emissions from 12,074 tpy to 11,186 tpy in 2012–2013 and to 10,142 tpy for 2014 and beyond. Potential additional allocation reductions of 20% may follow the CSAPR regulations as part of NAAQS which will require an even greater reduction in emission to meet the potential 8,114 tpy allocation in 2016–

2018. To meet the forthcoming CSAPR emission allocations and the potential NAAQS reductions, BREC will need to make a number of modifications to reduce NO_X emissions. A summary of the baseline emissions data, recommended modifications for CSAPR and NAAQS compliance, expected emission reductions, and the estimated NPV associated with the technology selections is provided below.

Table ES-2 — NO_X CSAPR Compliance Strategy (2014)

Unit	Baseline NO_X Emissions (tpy)	Current Annual NO_X Emission Rate (lb/MMBtu)	Technology Selection	Estimated New NO_X Emissions (tpy)	Estimated New Annual NO_X Emission Rate (lb/MMBtu)	Net Present Value at Baseline Credit Value (2011$ Million)
Coleman Unit C01	1,858	0.330	Advanced Burners	1,672	0.297	$0.32
Coleman Unit C02	1,585	0.332	Advanced Burners	1,427	0.299	$0.32
Coleman Unit C03	2,044	0.335	Advanced Burners	1,840	0.302	$0.32
Wilson Unit W01	934	0.052	None	934	0.052	N/A
Green Unit G01	2,050	0.206	None	2,050	0.206	N/A
Green Unit G02	2,168	0.215	SCR @ 85% Removal	325	0.032	$43.90
HMP&L Unit H01	460	0.071	None	460	0.071	N/A
HMP&L Unit H02	418	0.069	None	418	0.069	N/A
Reid Unit R01	512	0.522	Natural Gas with Existing Burners	292	0.298	See SO_2
Reid Unit RT	45	0.708	None	45	0.708	N/A
Fleet Total	**12,074**	**0.177**	**N/A**	**9,462**	**0.139**	**$44.9**

Table ES-3 — NO_X NAAQS Compliance Strategy (2016–2018)

Unit	Baseline NO_X Emissions (tpy)	Current Annual NO_X Emission Rate (lb/MMBtu)	Technology Selection	Estimated New NO_X Emissions (tpy)	Estimated New Annual NO_X Emission Rate (lb/MMBtu)	Net Present Value at Baseline Credit Value (2011$ Million)
Coleman Unit C01	1,858	0.330	Advanced Burners	1,672	0.297	$0.32
Coleman Unit C02	1,585	0.332	Advanced Burners	1,427	0.299	$0.32
Coleman Unit C03	2,044	0.335	Advanced Burners	1,840	0.302	$0.32
Wilson Unit W01	934	0.052	None	934	0.052	N/A
Green Unit G01	2,050	0.206	SCR @ 85% Removal	307	0.031	$46.50
Green Unit G02	2,168	0.215	SCR @ 85% Removal	325	0.032	$43.90
HMP&L Unit H01	460	0.071	None	460	0.071	N/A
HMP&L Unit H02	418	0.069	None	418	0.069	N/A
Reid Unit R01	512	0.522	Natural Gas with Existing Burners	292	0.298	See SO_2
Reid Unit RT	45	0.708	None	45	0.708	N/A
Fleet Total	**12,074**	**0.177**	**N/A**	**7,720**	**0.113**	**$91.4**

IMPLEMENTATION TIMELINE FOR CSAPR AND MACT COMPLIANCE (SO_2 AND NO_X)

Since BREC has a total of nine plants where potential modifications can affect overall fleet-wide compliance with CSAPR and potential NAAQS regulations, a running summation of emissions above and (below) their allocations was plotted along with the startup dates of the recommended modifications. Implementing the strategies below will allow BREC to achieve fleet-wide compliance with minimal credit purchases while major modifications are completed.

Figure ES-1 — Cumulative Emissions Above or Below CSAPR SO_2 and NO_X Allocations

(Adjusted Outage Schedule)

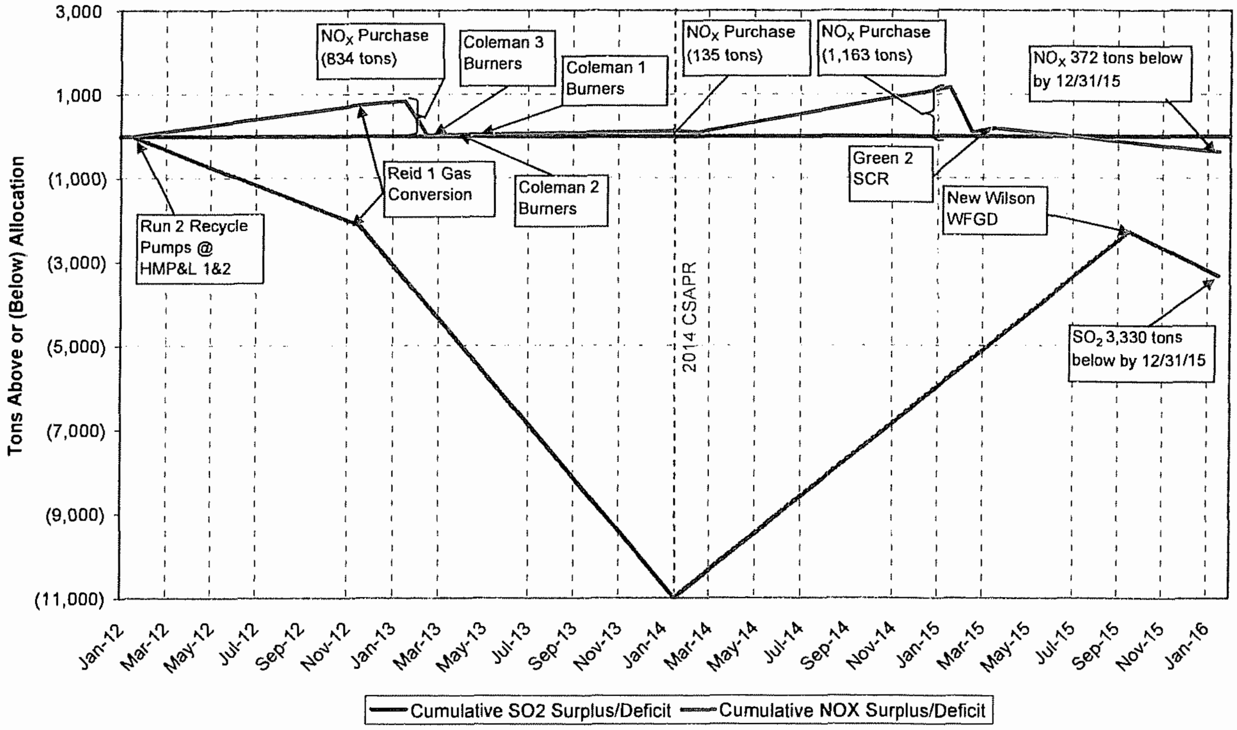
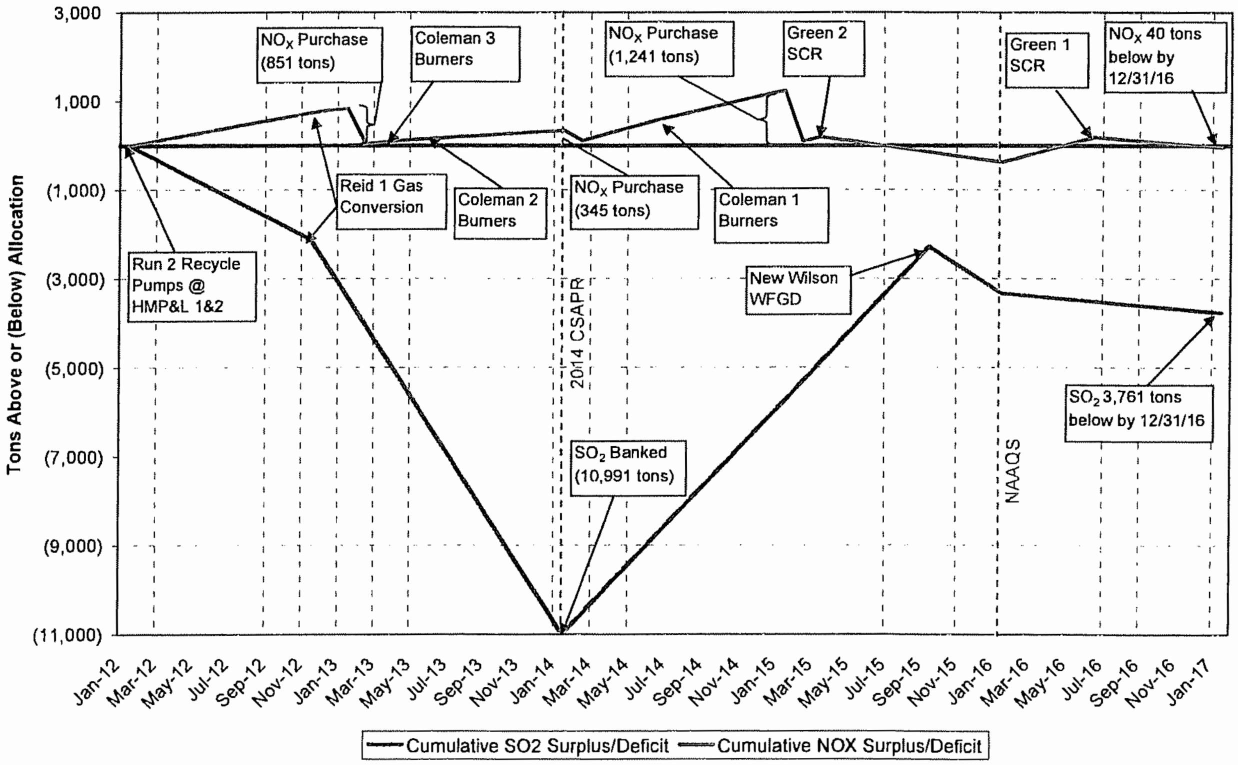


Figure ES-2 — Cumulative Emissions Above or Below CSAPR and NAAQS SO_2 and NO_X Allocations



MERCURY

Baseline mercury emissions at all BREC units except Henderson (HMP&L) are above the proposed MACT limit of 1.2 lb/TBtu and will need to be reduced to achieve compliance. It is anticipated that that activated carbon injection (ACI) systems will be required at each of the over-emitting units to lower emission rates to the required levels. A summary of each unit's baseline emissions, required reduction, recommended modification, and associated NPV are provided below.

Table ES-4 — MACT Hg Compliance Summary

Unit	Baseline Elemental Hg Emission Rate (lb/TBtu)	Baseline Oxidized Hg Emission Rate (lb/TBtu)	Baseline Total Hg Emission Rate (lb/TBtu)	Required Percent Reduction for MACT Compliance	Technology Selection	NPV (2011$ Million)
Coleman Unit C01	2.67	0.85	3.52	66%	Activated Carbon Injection	$11.9
Coleman Unit C02						$11.9
Coleman Unit C03						$11.9
Wilson Unit W01	1.56	0.21	1.77	32%	Activated Carbon Injection	$26.7
Green Unit G01	2.73	0.36	3.09	61%	Activated Carbon Injection	$15.3
Green Unit G02	2.46	0.12	2.58	53%	Activated Carbon Injection	$15.3
HMP&L Unit H01	0.34	0.28	0.62	N/A	None	N/A
HMP&L Unit H02	0.22	0.24	0.47	N/A	None	N/A
Reid Unit R01	N/A	N/A	6.5	82%	Natural Gas Conversion	N/A
TOTAL						$93.0

PARTICULATE MATTER

High condensable emission levels at Coleman and HMP&L a largely contributing to emission levels above the proposed limit of 0.030 lb/MMBtu. A reduction in condensable PM levels >50% can be achieved by adding a dry sorbent (hydrated lime) injection system, which would provide a large improvement in total PM emissions. To improve filterable removal efficiencies, it is suggested that BREC modify the existing electrostatic precipitators (ESPs) with advanced electrodes and high frequency transformer rectifier (TR) sets. The combination of these two modifications at HMP&L and Green should result in PM emissions below the MACT limit. Other BREC units that are considering ACI systems for mercury control and dry sorbent injection (DSI) systems for improved ACI efficiency and acid gas control should also consider upgrading the existing electrodes and installing high frequency TR sets to remain in compliance. However, testing on the affects of adding these systems should be conducted before implementing these strategies. Baseline TPM emissions, required reductions compliance, recommended equipment upgrades/modifications, and associated NPV to meet the anticipated MACT limits are provided below.

Table ES-5 — MACT TPM Compliance Summary

Unit	Baseline Total PM Emission Rate (lb/MMBtu)	Required Percent Reduction for MACT Compliance	Technology Selection	NPV (2011$ Million)
Coleman Unit C01	0.0398	25%	Hydrated Lime DSI & ESP Upgrades	$10.3
Coleman Unit C02				$10.3
Coleman Unit C03				$10.3
Wilson Unit W01	0.0196	N/A	Low Oxidation Catalyst & ESP Upgrades	$11.2
Green Unit G01	0.0195	N/A	Hydrated Lime DSI & Potential ESP Upgrades	$11.2
Green Unit G02	0.0169	N/A	Hydrated Lime DSI & Potential ESP Upgrades	$11.2
HMP&L Unit H01	0.0319	6%	Hydrated Lime, Low Oxidation Catalyst & ESP Upgrades	$11.2
HMP&L Unit H02	0.0324	7%	Hydrated Lime, Low Oxidation Catalyst & ESP Upgrades	$11.2
Reid Unit R01	0.269(1)	~90%	Natural Gas Conversion	N/A
TOTAL				$86.9

(1) Condensable particulate emission data was not available for Reid. Value shown is filterable particulate matter only.

AIR QUALITY COMPLIANCE RECOMMENDATION SUMMARY (CSAPR 2014 & MACT)

The table below provides the complete BREC fleet-wide recommended compliance strategy to meet the 2014 CSAPR and potentially forthcoming MACT regulations. Technologies selected along with estimated project capital costs are shown.

Table ES-6 — Air Quality Compliance Strategy Summary

	Technology Selection						Capital Cost (Millions $)						Total Projected Capital Cost (2011$)
	CSAPR - Selection		MACT - Selection										
BREC Unit	SO_2	NO_x	HCl	Hg	CPM	FPM	SO_2	NO_x	HCl	Hg	CPM	FPM	
Coleman Unit C01	None**	Advanced Burners	HCl level is below anticipated MACT limits. Installation of an HCl monitor is needed since SO2 can not be used as a surrogate.***	Activated Carbon Injection	Hydrated Lime - DSI	Advanced Electrodes & High Frequency TR Sets	0.00	5.94	0.32	4.00	5.00	2.72	$18,000,000
Coleman Unit C02	None**	Advanced Burners	HCl level is below anticipated MACT limits. Installation of an HCl monitor is needed since SO2 can not be used as a surrogate.***	Activated Carbon Injection	Hydrated Lime - DSI	Advanced Electrodes & High Frequency TR Sets	0.00	5.94	0.32	4.00	5.00	2.72	$18,000,000
Coleman Unit C03	None**	Advanced Burners	HCl level is below anticipated MACT limits. Installation of an HCl monitor is needed since SO2 can not be used as a surrogate.***	Activated Carbon Injection	Hydrated Lime - DSI	Advanced Electrodes & High Frequency TR Sets	0.00	5.94	0.32	4.00	5.00	2.72	$18,000,000
Wilson Unit W01	New Tower Scrubber - 99% removal	None	Higher L/G or new tower for increased SO2 removal to below 0.2 lb/mmBtu will permit reporting SO2 data as prima facia evidence of compliance with HCl emission limits	Activated Carbon Injection & New SCR Catalyst	Low Oxidation SCR catalyst + Hydrated Lime - DSI Control NH3 slip from SCR	Advanced Electrodes & High Frequency TR Sets	139.00	0.00	0.00	4.50	6.50	4.54	$154,500,000
Green Unit G01	None	None	HCl Montior is not required since SO2 is below 0.2 lb/mmBtu	Activated Carbon Injection	Hydrated Lime - DSI	Potential ESP Upgrades Due to ACI and DSI	0.00	0.00	0.00	4.00	5.00	3.34	$12,300,000
Green Unit G02	None	SCR @ 85% Removal	HCl Montior is not required since SO2 is below 0.2 lb/mmBtu	Activated Carbon Injection	Hydrated Lime - DSI	Potential ESP Upgrades Due to ACI and DSI	0.00	81.00	0.00	4.00	5.00	3.34	$93,300,000
HMP&L Unit H01	Run both pumps & spray levels, install 3rd pump as spare	None	Higher L/G for increased SO2 removal to below 0.2 lb/mmBtu will permit reporting SO2 data as prima facia evidence of compliance with HCl emission limits	None needed due to oxidation across SCR and WFGD	Low Oxidation SCR catalyst + Hydrated Lime - DSI Control NH3 slip from SCR	ESP Maintenance / Possible Upgrade	3.15	0.00	0.00	0.00	6.00	2.50	$11,700,000
HMP&L Unit H02	Run both pumps & spray levels, install 3rd pump as spare	None	Higher L/G for increased SO2 removal to below 0.2 lb/mmBtu will permit reporting SO2 data as prima facia evidence of compliance with HCl emission limits	None needed due to oxidation across SCR and WFGD	Low Oxidation SCR catalyst + Hydrated Lime - DSI Control NH3 slip from SCR	ESP Maintenance / Possible Upgrade	3.15	0.00	0.00	0.00	6.00	2.50	$11,700,000
Reid Unit R01*	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	1.20						$1,200,000
Reid Unit RT	None	None	None	None	None	None	0.00						$0
TOTAL							146.5	98.8	1.0	24.5	43.5	24.4	$339,000,000

**Note SO2 emissions in this scenario have been adjusted to reflect recent data received from BREC confirming that the Coleman FGD is capable of producing emission rates of 0.25lb/MMBtu and reaching removal rates of approximately 95%.

***Note four (4) HCl monitors are required for Coleman. One (1) for the common WFGD stack and one (1) for each unit bypass stack

EPA 316(b) REGULATIONS FOR COOLING WATER INTAKES

The existing intake screens at Coleman and Sebree are not equipped with fish buckets or return systems, and the intake velocities approaching the screens are approximately 1.8 and 2.3 feet per second (fps), respectively, at the low water level. This study evaluated several different technologies that provide for compliance with these proposed regulations, including new screen designs and conversion to closed cycle cooling. Since the proposed regulations do not mandate a conversion to closed cycle cooling, it is recommended that replacement intake screens be installed. The recommended screen technology based on an evaluation of capital and O&M costs is a rotating circular intake screen with fish pumps to meet the expected impingement mortality reduction. The estimated capital cost of these screens is $1.33M for each of the Coleman units and $2.05M for Sebree. Projected annual O&M costs are estimated to be $250,000 per unit at Coleman and $370,000 at Sebree.

COAL COMBUSTION RESIDUAL HANDLING & WASTE WATER EFFLUENTS

Assuming Subtitle D is promulgated, modifications would be required at Coleman, HMP&L, and Green to comply. Although continued operation of the existing bottom ash dewatering ponds may be possible under the new regulations, this is not expected to be practical due to requirements for pond modifications (liner and groundwater monitoring system installation) and pending wastewater discharge standards that will likely necessitate treatment or elimination of the ash pond discharge streams. As such, a conversion to a dry bottom ash system using submerged scraper conveyors (SSCs) is recommended. The resulting NPV associated with SSC installation and closure of the existing ash ponds is provided below.

Table ES-7 — Coal Combustion Residue Compliance Summary

Station	Technology Selected	Capital Cost (2011$ Millions)	NPV (2011$ Millions)
Coleman	Dry Bottom Conversion – Remote SSC & Fly Ash Conversion to Dry Pneumatic	$38.0	$45.6
Wilson	None	N/A	N/A
Green	Dry Bottom Conversion – Remote SSC	$28.0	$37.0
HMP&L	Dry Bottom Conversion – Remote SSC	$28.0	$34.1
Reid	None	N/A	N/A

Last page of Executive Summary.

1. OBJECTIVES AND APPROACH TO STUDY

The U.S. Environmental Protection Agency (EPA) and the U.S. Congress have been actively developing environmental regulations and legislation that will impact coal and oil-fired power plant operations. Air pollution regulations are aimed at requiring reductions of the criteria air pollutants including sulfur dioxide (SO_2), nitrogen oxides (NO_X), and particulate matter (PM, including PM10 and PM2.5), and will likely compel additional control of other air pollutants including mercury, acid gases, trace metals, and potentially carbon dioxide (CO_2). Additional EPA regulations are being developed for cooling water intakes that will reduce impingement mortality and entrainment of fish, eggs, larvae, and other aquatic organisms that come in contact with a station's cooling water system. These regulations, referred to as the EPA's 316(b) regulations, are expected to require modifications to a plant's cooling water system. The EPA is also proposing alternative approaches for regulating coal combustion residual (CCR) waste products. It is expected that the regulatory requirements will make continued operation of dewatering ponds impractical, necessitating conversions from wet to dry bottom ash systems and the subsequent closures of the dewatering ponds. Wastewater discharge effluent guidelines being proposed by the EPA will likely also impact the station's ability to discharge large volumes of ash sluice water to the environment, due to limits on total dissolved solids, metals, pH and other parameters, further necessitating the dry bottom ash conversions.

1.1 OBJECTIVES

Big Rivers Electric Corporation (BREC) requested Sargent & Lundy, L.L.C. (S&L) to perform a comprehensive compliance study addressing the recently issued, proposed and pending environmental regulations and legislation, and the potential impacts these initiatives may have on operations at BREC's Kenneth C. Coleman, D.B. Wilson, and Sebree (Reid, Henderson and Green units) generating stations.

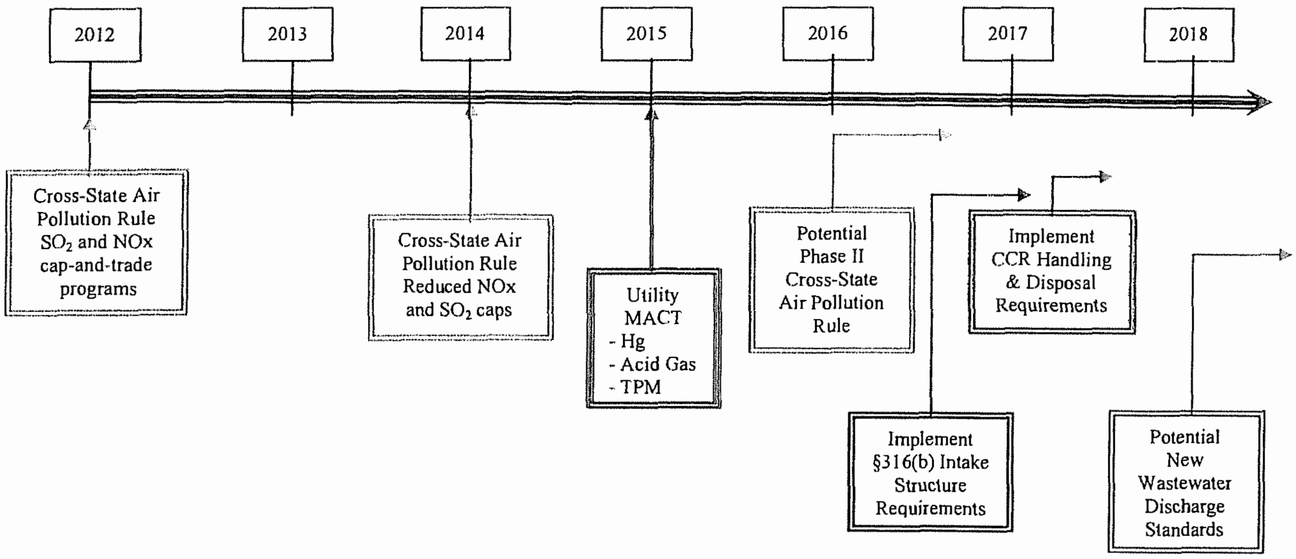
This study examines the compliance requirements of the Cross-State Air Pollution Rule (CSAPR), the anticipated compliance requirements of the EPA's proposed Electric Generating Utility Maximum Achievable Control Technology (EGU MACT) regulation, and the pending CCR and 316(b) regulations. The study was completed in three phases, as follows:

- **Phase I.** A review of the potential regulatory outcomes for pending rules.

- **Phase II.** A review of candidate technologies to meet the anticipated regulations
- **Phase III.** A technology evaluation, including a net present value (NPV) analysis where necessary, based on capital and O&M costs to determine the optimum solution for BREC.

This evaluation was conducted to provide BREC with technology recommendations that will economically comply with the current and pending regulatory requirements. The technologies reviewed included upgrades to existing environmental control systems and the installation of new technologies. Figure 1-1 provides a timeline showing the anticipated promulgation and implementation of the various environmental regulatory initiatives currently imposed or being considered by EPA that will affect operation of the Big River units.

Figure 1-1 — Environmental Regulatory Implementation Timeline



Although several environmental initiatives are currently being advanced by EPA, the regulatory initiatives that will have the most immediate impact on the BREC generating units are the CSAPR and the proposed Utility MACT Rule.

1.2 BASIS OF STUDY

The design basis values and assumptions for this study are summarized in Table 1-1 below. Historical plant data, emission test reports, and other key input data received from BREC are included in Appendix 5 for reference.

Table 1-1 — Economic Evaluation Parameters

Economic Parameter	Value
Installation Year	2014
Cost Estimate Basis Year	2011
Operating Life of the Facility, starting 2014 (years)	20
Discount Rate (%)	7.93%
Capital Cost Escalation Rate (%)	2.5%
Operating and Maintenance (O&M) Escalation Rate (%)	2.5%
Levelized Fixed Charge Rate (20 years) (%)	10.13%
Operating Labor Rate - Pay Includes Benefits ($/hr)	70
Auxiliary Power Cost ($/MWh)	40
Delivered Cost of Sorbent - Hydrated Lime ($/ton)	100
Delivered Cost of Activated Carbon ($/ton)	2000
Delivered Cost of Fuel Additive - Calcium Bromide ($/ton)	2200
Delivered Cost of Ammonia ($/ton)	866
Delivered Cost of Urea ($/ton)	540
Delivered Cost of Lime ($/ton)	120
Delivered Cost of Limestone ($/ton) – Wilson	18
Delivered Cost of Limestone ($/ton)	21
Additional Ash Disposal Costs Under Proposed Regulations for Coal Combustion Residuals (Subtitle D) ($/ton)	2.5
SO_2 Allowance Estimated Cost ($/ton)	500
NO_X Allowance Estimated Cost ($/ton)	2500
Natural Gas Cost ($/MMBtu)	4.50
Coal Cost ($/ton)	48

1.2.1 Estimating Basis

Capital and O&M costs estimates were developed for the various technology selections using S&L historical project information, escalated as required to reflect 2011 dollars. In order to provide BREC with the lowest-cost approach and highest level of control over schedule and design, the capital costs estimates provided are based on a minimal-contracts approach to project execution,. The costs provided include all direct and indirect construction costs, engineering, escalation, and 10%–20% contingency (depending on technology) based on project cost source similarity, project execution date, and other factors relating to price confidence. However, owner's costs are not included. Since these estimates are not based on detailed takeoffs or project-specific bid information, the typical range of accuracy is approximately ±20%. This is consistent with a Class 4 study or feasibility estimate, as defined by the Association for the Advancement of Cost Estimating (AACE) International Recommended Practice 18R-97.

1.2.2 Study Basis Input Parameters and Assumptions

Study basis input parameters were established based on a review of historical plant operating data and input received directly from BREC, including recent emissions tests performed in July/August 2011. A summary of key input parameters are provided in Table 1-2 through Table 1-4.

Table 1-2 — Facility Baseline Summary for Coleman & Wilson

Parameter	Coleman Unit C01		Coleman Unit C02		Coleman Unit C03		Wilson Unit W01	
Gross Unit Output (MW)	160		160		165		440	
Full Load Heat Input (MMBtu/hr)	1,800		1,800		1,800		4,585	
Primary Fuel	Illinois Basin bituminous		Illinois Basin bituminous		Illinois Basin bituminous		Illinois Basin bituminous	
Secondary Fuel	N/A		N/A		N/A		Pet Coke Pelletized Fines #2 Fuel Oil	
Unit Description	Dry bottom wall-fired boiler		Dry bottom wall-fired boiler		Dry bottom wall-fired boiler		Dry bottom wall-fired boiler	
NO_X Control	LNB & ROFA		LNB & OFA		LNB & OFA		LNB/OFA/SCR	
PM Control	ESP		ESP		ESP		ESP	
SO_2 Control	Wet Limestone FGD		Wet Limestone FGD		Wet Limestone FGD		Wet Limestone FGD	
Condenser Cooling System	Once-through cooling		Once-through cooling		Once-through cooling		Closed cycle cooling	
Baseline Average Annual Heat Input(1) (MMBtu)	11,784,789		11,787,242		12,570,106		37,043,481	
2010 Annual Heat Input (MMBtu)	11,254,853		9,544,382		12,195,952		36,221,670	
Baseline Annual SO_2 Emissions(2) (tpy) / (lb/MMBtu)	1,473	0.25	1,473	0.25	1,571	0.25	9,438	0.51
Annual NO_X Emissions (2010) (3) (tpy) / (lb/MMBtu)	1,858	0.33	1,585	0.33	2,044	0.34	934	0.053
Ozone Season NO_X Emissions (2010) (3) (tons) / (lb/MMBtu)	733	0.33	735	0.34	857	0.34	378	0.050

(1) Baseline average annual heat inputs provided in this table represent the average of the three highest heat input years during the baseline years 2006-2010.

(2) Baseline annual SO_2 emissions represent the average of the three highest emission years (2006 – 2010); however, baseline SO_2 emissions from Coleman Units C01, C02, and C03 were adjusted to an annual average emission rate of 0.25 lb/MMBtu based on information provided by BREC.

(3) Baseline NO_X emission rates are calculated using 2010 NO_X emissions and 2010 heat inputs.

Table 1-3 — Facility Baseline Summary for Sebree

Parameter	Green Unit G01		Green Unit G02		Henderson Unit H01		Henderson Unit H02		Reid Unit R01		Reid Unit RT	
Gross Unit Output (MW)	252		244		172		165		72		70	
Full Load Heat Input (MMBtu/hr)	2,569		2,569		1,624		1,624		911		803	
Primary Fuel	Illinois basin bituminous		Illinois basin bituminous		Illinois basin bituminous		Illinois basin bituminous		Illinois basin bituminous		natural gas	
Secondary Fuel	Pet Coke		Pet Coke		N/A		N/A		N/A		Oil	
Unit Description	Dry bottom wall-fired boiler		Dry bottom wall-fired boiler		Dry bottom wall-fired boiler		Dry bottom wall-fired boiler		Dry bottom wall-fired boiler		Combustion Turbine	
NO_X Control	LNB		LNB		LNB/SCR		LNB/SCR		LNB			
PM Control	ESP		ESP		ESP		ESP		Cyclone ESP			
SO_2 Control	Wet Lime FGD		Wet Lime FGD		Wet Lime FGD		Wet Lime FGD					
Condenser Cooling System	Closed cycle cooling		Closed cycle cooling		Closed cycle cooling		Closed cycle cooling		Once-through cooling			
Baseline Average Annual Heat Input[(1)] (MMBtu)	20,128,359		20,347,531		12,823,005		13,214,893		2,240,807		87,379	
2010 Annual Heat Input (MMBtu)	19,866,020		20,128,970		13,003,466		12,118,692		1,962,424		126,361	
Baseline Annual SO_2 Emissions[(2)] (tpy) / (lb/MMBtu)	1,873	0.19	1,414	0.14	2,227	0.35	2,745	0.42	5,066	4.52	5	0.12
Annual NO_X Emissions (2010)[(3)] (tpy) / (lb/MMBtu)	2,050	0.21	2,168	0.22	460	0.071	418	0.069	512	0.52	45	0.71
Ozone Season NO_X Emissions (2010)[(3)] (tons) / (lb/MMBtu)	789	0.20	890	0.21	208	0.074	179	0.066	193	0.47	33	0.70

(1) Baseline annual heat inputs shown in this table represent the average of the three highest heat input years during the years 2006 – 2010.

(2) Baseline annual SO_2 emissions shown in this table represent the average of the three highest emission years during the years 2006 – 2010.

(3) Baseline NO_X emission rates are calculated using 2010 NO_X emissions and 2010 heat inputs.

Table 1-4 — MACT Emission Test Data

Proposed MACT Emission Limits		Stack Emission Test Data[1]						
		Coleman	Wilson	Green 1	Green 2	HMP&L 1	HMP&L 2	Reid 1
a. Total particulate matter (TPM)	0.030 lb/MMBtu	0.0398	0.0196	0.0195	0.0169	0.0319	0.0324	0.269[2]
OR								
Total non-Hg HAP metals	0.000040 lb/MMBtu	0.0000910	0.0000591	0.0000906	0.0000678	0.0000959	0.0001203	N/A
b. Hydrogen chloride (HCl)	0.0020 lb/MMBtu	0.000236	0.000074	0.000281	0.000334	0.001670	0.001370	0.068
OR								
Sulfur dioxide (SO_2)	0.20 lb/MMBtu	0.250	0.510	0.186	0.139	0.347	0.415	4.52
c. Mercury (Hg)	1.2 lb/TBtu	3.52	1.77	3.09	2.58	0.62	0.47	6.5

(1) Green cells indicate baseline emissions below the applicable MACT emission limit. Yellow cells indicated emissions below, but within 15% of the proposed emission limit. Red cells indicate baseline emissions above the applicable MACT emission limit.

(2) Condensable particulate emission data was not available for Reid. Value shown is filterable particulate matter only.

Per discussions with BREC, it is understood that approximately 70% of load generating capacity is used by two local aluminum smelters. Being that a majority of output is consumed by this group, it was agreed that a load-forecasting study would not be developed. Furthermore, BREC requested that S&L assume the BREC units will continue to operate in a manner similar to that demonstrated over IRC data collection years (2006-2010).

Existing acid gas emissions were based on recent test data at the various units stack outlets. Acid gas emissions for Reid Unit 1 are estimates only and are not based on tests.

It is assumed that the existing wet flue gas desulfurization (WFGD) systems at Green Units 1 & 2 will consistently perform up to the historical peak removal efficiency.

It is assumed that Wilson station will maintain its current intake water demands and continue to operate with a through-screen velocity at or below the required 0.5 fps per the provided Kentucky Pollutant Discharge Elimination System (KPDES) fact sheets.

Since the Henderson (HMP&L) units are owned by the City of Henderson, BREC has requested that the HMP&L units be able to meet their own CSAPR allocations and stand alone if need be.

Per discussions with BREC, HMP&L 1 and 2 and Wilson have already committed to upgrading their existing Low-NO_X burners due to high O&M costs associated with the current burners.

Technology selection for CSAPR compliance was based on the most economic method for achieving compliance with BREC's 2014 allocations.

Last page of Section 1

2. PHASE I – ENVIRONMENTAL REGULATORY REVIEW

Compliance with EPA's existing and proposed regulations will require a review of the following regulations:

- CAIR – Clean Air Interstate Rule (2010-2012)
- CSAPR – Cross-State Air Pollution Rule (2012-2014/2016)
- MACT – Maximum Available Control Technology for controlling mercury, acid, non-mercury metallic pollutants and organic air toxics including dioxin/furnas.(2015/2016)
- 316 (b) Cooling Water Intake Regulations.
- Waste Water Discharge Standards
- Coal Combustion Residue Regulation

2.1 AIR POLLUTION CONTROL SUMMARY

2.1.1 Clean Air Interstate Rule

CAIR includes an annual SO_2 cap-and-trade program, an annual NO_X cap-and-trade program, and an ozone season NO_X cap-and-trade program. CAIR went into effect in its entirety on January 1, 2009, and will remain in effect until the recently published CSAPR takes effect on January 1, 2012.

Actual SO_2 and NO_X emissions from the BREC generating units are currently very close to the corresponding CAIR Phase I SO_2 and NO_X allocation requirements. Annual SO_2 emissions from all units averaged 27,280 tpy (average of highest three years) between 2006 and 2010 (or 54,560 CAIR SO_2 allowances) compared to an allocation of 52,470 allowances. Thus, based on average historical emissions, BREC should be slightly above their CAIR Phase I SO_2 allocations without providing additional SO_2 emission controls. If SO_2 emissions exceed the CAIR allocations in any individual year, banked CAIR allocations and banked pre-2009 Acid Rain Program SO_2 allocations can be used to off-set any allocation deficit.

Systemwide annual and ozone season NO_X emissions were also slightly above the CAIR Phase I NO_X allocations. In 2010, annual NO_X emissions from all units were approximately 6% above the CAIR Phase I allocation of 11,351 tons, and ozone season NO_X emissions from all units were approximately 3.4% above the CAIR Phase I allocation of 4,824 tons. Relatively small NO_X reductions on the non-SCR controlled units (e.g., C01, C02, C03, G01, and G02) could provide the emissions reductions needed for systemwide NO_X emissions to maintain emissions at or below the CAIR Phase I NO_X allocation requirements.

Table 2-1 below provides a summary of CAIR Phase I allowance requirements and corresponding emission reduction requirements for each BREC generating unit:

Table 2-1 — CAIR Phase I Summary

Pollutant	Station	Baseline Emissions (Required Allocations - 2x Emissions)	CAIR Phase I Allocations (per year)	Reductions Needed to Meet Allocations
SO_2	Coleman	4,517 (9,034)	15,709	NA
	Wilson	9,438 (18,876)	12,461	(6,415)
	Sebree	13,325 (26,650)	24,300	(2,350)
	Systemwide	27,280 (54,560)	52,470	(2,090)
NO_X	Coleman	5,487	2,679	(2,808)
(Annual)	Wilson	934	3,210	NA
	Sebree	5,653	5,462	(191)
	Systemwide	12,074	11,351	(723)

2.1.2 Cross-State Air Pollution Rule

The CSAPR will replace CAIR in 2012. The rule includes a new SO_2 cap-and-trade program and new annual and ozone-season NO_X trading programs. Potential impacts of the CSAPR are summarized in Table 2-2 below:

Table 2-2 — BREC CSAPR SO_2 and NO_X Reduction Requirements (2012 and 2014)

Fleet-Wide Emission	Annual Allowances (tpy)		Baseline Annual Emission (tpy)	Required Reduction	
	2012	2014		2012	2014
SO_2	26,478	13,643	27,286	3%	50%
Annual NO_X	11,186	10,142	12,074	7%	16%
Ozone Season NO_X	4,972	4,402	4,995	0.5%	12%

Reductions of approximately 50% and 16% from BREC's baseline emissions are needed to meet the 2014 SO_2 and NO_X annual allocations. The largest contributors to the overall SO_2 deficit are the Wilson W01 and Reid R01 units, which have emission rates of 0.51 lb/MMBtu and 4.522 lb/MMBtu, respectively. The largest contributors to the overall NO_X deficit are Reid RT, Reid R01, and Coleman C03, which have baseline emission rates of 0.71 lb/MMBtu, 0.52 lb/MMBtu and 0.34 lb/MMBtu respectively.

2.1.3 Maximum Achievable Control Technology

The Proposed Utility MACT rule includes emission limits for mercury, acid gases (HCl or SO_2), and trace metal HAP emissions (which includes TPM, total non-Hg metals, or individual non-Hg metals). Based on the HAP emissions data available from the BREC coal-fired units, and taking into consideration Information Collection Request (ICR) emissions data from similar sources, it is foreseen that modifications are required throughout the BREC fleet to meet the proposed Utility MACT emission limits. Tables below compare existing emissions from each unit to the proposed emission limits and identify the emission reductions that may be needed to comply with the proposed MACT standards.

Since this study was completed, the MACT rule was replaced by the Mercury and Air Toxins Standard (MATS). This report has not been revised to reflect the new MATS rule.

Table 2-3 — Comparison of Baseline Hg Emissions to the Proposed MACT Hg Emission Limit

BREC Unit	Hg		
	Baseline (lb/TBtu)	Proposed MACT (lb/TBtu)	Required Reduction
Coleman Unit C01 Coleman Unit C02 Coleman Unit C03	3.5	1.2	66%
Wilson Unit W01	1.77	1.2	32%
Green Unit G01	3.1	1.2	61%
Green Unit G02	2.6	1.2	53%
HMP&L Unit H01	0.62	1.2	None
HMP&L Unit H02	0.47	1.2	None
Reid Unit R01	6.5 (one test)	1.2	82%

Table 2-4 — Comparison of Baseline Acid Gas Emissions to the Proposed MACT Acid Gas Limits

BREC Unit	Acid Gas Emissions					
	HCl (lb/MMBtu)			SO_2 (lb/MMBtu)		
	Baseline	MACT	Required Reduction	Baseline	MACT	Required Reduction
Coleman Unit C01 Coleman Unit C02 Coleman Unit C03	0.24×10^{-3}	2.0×10^{-3}	None	0.25	0.20	20%
Wilson Unit W01	0.07×10^{-3}	2.0×10^{-3}	None	0.51	0.20	61%
Green Unit G01	0.28×10^{-3}	2.0×10^{-3}	None	0.19	0.20	None
Green Unit G02	0.33×10^{-3}	2.0×10^{-3}	None	0.14	0.20	None
HMP&L Unit H01	1.67×10^{-3}	2.0×10^{-3}	None	0.35	0.20	43%
HMP&L Unit H02	1.37×10^{-3}	2.0×10^{-3}	None	0.42	0.20	52%
Reid Unit R01*	68.0×10^{-3}	2.0×10^{-3}	97%	4.52	0.20	96%

* Baseline HCl emissions summarized above represent estimated emission rates based on limited available stack test data. Additional stack test data would be needed to more accurately predict HCl emissions from each unit.

Table 2-5 — Comparison of Baseline TPM Emissions to the Proposed MACT TPM Emission Limit

BREC Unit	Total PM Emissions		
	Baseline (lb/MMBtu)	Proposed MACT (lb/MMBtu)	Required Reduction
Coleman Unit C01	0.0398	0.030	25%
Coleman Unit C02			
Coleman Unit C03			
Wilson Unit W01	0.0196	0.030	None
Green Unit G01	0.0195	0.030	None
Green Unit G02	0.0169	0.030	None
HMP&L Unit H01	0.0319	0.030	6%
HMP&L Unit H02	0.0324	0.030	7%
Reid Unit R01	0.269(1)	0.030	~90%

(1) Condensable particulate emission data was not available for Reid. Value shown is filterable particulate matter only.

2.1.4 Phase II Cross-State Air Pollution Rule

The 8-hour ozone and PM2.5 National Ambient Air Quality Standards (NAAQS) are the regulatory drivers for CSAPR. As discussed in section 3.5 of Appendix 1, EPA is considering revising the existing 8-hour ozone and PM2.5 NAAQS, making the ambient air quality standards more stringent. If revisions to the NAAQS are finalized, it is almost certain that more areas in Kentucky, and other downwind states, will be designated as ozone and PM2.5 non-attainment areas.

EPA could revise the CSAPR to address the new 8-hour ozone and PM2.5 NAAQS. If so, it is likely that Phase II CSAPR would address the new ozone and PM2.5 NAAQS standards by reducing each state's CSAPR allocation budget. EPA would conduct ambient air quality impact modeling to identify emissions that contribute to the new non-attainment area designations and then revise the emission budgets to eliminate each state's contribution to downwind non-attainment. For this analysis, it was assumed that the Phase II CSAPR allocations will be 20% below the Phase I allocations and that the Phase II rule will take effect in the 2016–2018 timeframe.

Projected emission allocations, baseline annual emissions, and potential required reductions are shown in Table 2-6 below.

Table 2-6 — BREC CSAPR Phase II SO_2 and NO_X Reduction Requirements

Fleet-Wide Emission	Annual Allowances (tpy)	Baseline Annual Emission (tpy)	Required Reduction
SO_2	10,914	27,286	60%
Annual NO_X	8,114	12,074	33%
Ozone Season NO_X	3,522	4,995	30%

Assuming a total systemwide annual heat input of 136,400,000 MMBtu and a total ozone season heat input of 57,200,000 MMBtu, NO_X emissions from all BREC units would have to average approximately 0.12 lb/MMBtu to match the projected Phase II CSAPR allocations. A systemwide average emission rate of 0.12 lb/MMBtu is approximately 33% below the current systemwide average NO_X emission rate of 0.177 lb/MMBtu.

2.2 316(B) WATER INTAKE IMPINGEMENT MORTALITY & ENTRAINMENT – REGULATORY SUMMARY

As detailed in Appendix 1, on April 20, 2011, the EPA published in the Federal Register proposed regulations implementing §316(b) of the Clean Water Act (CWA) at all existing power generating facilities and all existing manufacturing and industrial facilities that withdraw more than 2 million gallons per day (MGD) of water from waters of the U.S. and use at least 25% of the water they withdraw exclusively for cooling purposes. The newly proposed rule, as applicable to BREC's units, proposes reductions in impingement mortality by selecting one of two options for meeting Best Technology Available (BTA) requirements. Option 1 requires the owner or operator of an existing facility to install, operate, and maintain control technologies capable of achieving the following impingement mortality limitations for all life stages of fish:

Table 2-7 — Impingement Mortality Not-to-Exceed Values

Regulated Parameter	Annual Average	Monthly Average
Fish Impingement Mortality	12%	31%

The proposed impingement mortality performance standards are based on the operation of a modified course mesh traveling screen with technologies such as fish buckets or pumps, a low-pressure spray wash, and dedicated fish return lines implemented. However, the proposed rule does not specify any particular screen configuration, mesh size, or screen operations, so long as facilities can continuously meet the numeric impingement mortality limits.

Under Option 2, facilities may choose to comply with the impingement mortality standards by demonstrating to the permitting agency that its cooling water intake system has a maximum intake velocity of 0.5 fps. The maximum velocity must be demonstrated as either the maximum design intake velocity or the maximum actual intake velocity as water passes through the structural components of a screen measured perpendicular to the screen mesh. Typically, this intake velocity will correspond to the through-screen velocity. The maximum velocity limit must be achieved under all conditions, including during minimum ambient source surface elevations and during periods of maximum head loss across the screens during normal operation of the intake structure.

The Proposed 316(b) Rule also includes entrainment mortality performance standards applicable to existing units with a design intake flow >2 MGD, existing units with a design intake flow >125 MGD, and new units. Proposed entrainment performance standards are summarized below. For entrainment mortality, the proposed rule establishes requirements for studies as part of the permit application, and then establishes a process by which BTA for entrainment mortality would be implemented at each facility on a case-by-case basis. These case-by-case performance standards must reflect the permitting agency's determination of the maximum reduction in entrainment mortality warranted after consideration of all factors relevant for determining the BTA at each facility. Factors that the permitting agency must consider when making a case-by-case entrainment mortality determination include the following:

- Number and types of organisms entrained
- Entrainment impacts on the water body
- Quantified and qualitative social benefits and social costs of available entrainment technologies, including ecological benefits and benefits to any threatened or endangered species
- Thermal discharge impacts
- Impacts on the reliability of energy delivery within the immediate area

- Impact of changes in particulate emissions or other pollutants associated with entrainment technologies
- Land availability inasmuch as it relates to the feasibility of entrainment technology
- Remaining useful plant life
- Impacts on water consumption

In addition, existing facilities with an actual intake flow of greater than 125 MGD must conduct the following additional entrainment mortality studies and evaluations as part of the BTA determination:

- Entrainment Mortality Data Collection Plan (with peer reviewers identified)
- Peer-reviewed Entrainment Mortality Data Collection Plan
- Completed Entrainment Characterization Study
- Comprehensive Technical Feasibility and Cost Evaluation Study, including—
  - — Benefits Valuation Study
  - — Non-water Quality and Other Environmental Impacts Study

2.3 WASTEWATER DISCHARGE

EPA has indicated in the October 2009 *Detailed Study Report* that wastewaters from air pollution control devices are of primary concern, in particular, mercury and other heavy metals. At this point, it is difficult to accurately anticipate what affect these regulations may have on coal-fired generating station operations. A brief summary of the potential wastewater discharge requirements is provided in Table 2-8 below.

Table 2-8 — Potential Wastewater Effluent Discharge

BREC Station	KPDES Permit No.	Receiving Water	Facility Summary
Coleman	KY001937	Ohio River	Because this plant discharges directly to the Ohio River, Ohio State Sanitation Commission (ORSANCO) requirements will apply to the effluent. Even though the effluent guidelines have not yet been promulgated, the concentration of mercury in water entering the river will be required to meet the ORSANCO limit of 0.000012 mg/L (in addition to other metals limitations). The permit also requires the Coleman plant to monitor for total recoverable metals and hardness. The results of this monitoring will be incorporated into the next permit application and may result in numeric discharge limits for these substances. The FGD wastewater and other wastewaters generated by the plant will have to meet the Steam Electric Power Effluent Guidelines, which are expected to be similar to ORSANCO standards. Depending upon the discharge limits for mercury and other constituents in the KPDES permit it may become necessary to install advanced wastewater treatment/removal systems for mercury and other metals.
Wilson	KY0054836	Green River and Elk Creek	The KPDES permit requires monitoring for hardness, sulfate, and chloride. The results of this monitoring may be used to demonstrate the need for numeric effluent standards for these parameters in future permits. Further, the required monitoring for total recoverable metals indicates a potential for future limits based on the data developed. It is expected that the new Steam Electric Power Effluent Guidelines will result in more stringent effluent requirements for this facility. The existing permit fact sheet relied heavily on the requirements of 40 CFR 423. Depending upon the discharge limits for sulfates, chlorides, mercury and other constituents in the KPDES permit it may become necessary to install advanced wastewater treatment/removal systems for mercury and other metals.
Sebree	KY001929	Green River	The Green and Henderson facilities are equipped with cooling towers that contribute 1.9 MGD and 7.20 MGD respectively to the overall discharge. Because the facilities discharge to the Green River, it is expected that the new Steam Electric Power Effluent Guidelines will drive the effluent limits. The facility currently has a 1,200 ppm chloride limit. Cooling tower blowdown and FGD blowdown may contain high levels of chloride, which is difficult and expensive to remove. The permit also requires monitoring for total recoverable metals and hardness, indicating a potential for numeric effluent standards for metals in the next round of permitting. It is not known whether the potential numeric standards will be more or less stringent than any that may be proposed in the update of 40 CFR 423. Depending upon the discharge limits for sulfates, chlorides, mercury, and other constituents in the KPDES permit, it may become necessary to install advanced wastewater treatment and/or removal systems for mercury and other metals.

2.4 COAL COMBUSTION RESIDUE – REGULATORY SUMMARY

Two alternate regulations for the management of coal combustion residuals (CCR) have been issued for public comment. Both options fall under the Resource Conservation and Recovery Act (RCRA). Under the first proposal, EPA would list these residuals as special wastes under the hazardous waste provisions of Subtitle C of RCRA, when destined for disposal in landfills or surface impoundments. With Subtitle C, the waste products would need to be trucked by specially licensed hazardous waste carriers and be taken to an alternate landfill suitable for hazardous waste at significant additional cost. Although not specifically addressed in the proposed Subtitle C regulations, existing ash ponds used strictly for dewatering would likely require significant improvements to meet Subtitle C regulations, even though they are not used for long-term storage of CCRs. Product handling, transportation, and disposal costs under Subtitle C are substantial due to the hazardous material classification resulting in higher costs for insurance, taxes, licensing, manifesting, documentation, and training.

Under the second proposal, EPA would regulate coal ash under Subtitle D of RCRA, the section for non-hazardous wastes. If the Subtitle D regulations are promulgated (i.e., non-hazardous waste), the existing manner in which the waste materials are transported is considered acceptable; however, some additional landfill costs may still be incurred by BREC's units due to Subtitle D requirements for lining of landfills and ongoing groundwater monitoring.

Pending revisions to the wastewater discharge standards for steam electric power plants may have a significant impact on the bottom ash systems operations at the Green, HMP&L, Reid, and Coleman stations. It is difficult to predict the specific type of treatment and associated costs that will be required; however, given the large volume of ash sluicing water that discharges through the stations' ponds, the costs of any treatment mandated by pending regulations will be substantial. As such, even if the Subtitle D (non-hazardous) regulations are promulgated, continued operation of the existing ash dewatering ponds may not be possible. Since the specific water quality parameters (e.g., selenium, mercury, total suspended solids) and compliance limits of the future wastewater discharge standards are unknown, a conversion to a dry bottom ash system is recommended and included as the study basis. Table 2-9 below gives a brief summary of the existing facilities and potential impacts of the proposed regulations.

Table 2-9 — Coal Combustion Residue Summary

Station	Bottom Ash Handling	Economizer Ash Handling	Pyrites Handling	Fly Ash Handling	Modifications Required for Subtitle C	Modifications Required for Subtitle D
Coleman	Sluiced to Pond	Sluiced to Pond	Sluiced to Pond	Sluiced to Pond	Maintain Piping System and Add Dewatering Equipment to Eliminate Pond Storage & Install Pneumatic Transport System for Fly Ash	Maintain Piping System and Add Dewatering Equipment to Eliminate Pond Storage. Landfill waste product.
Wilson	SSC under Boiler	Sluiced to Bottom Ash SSC	Handled Dry	Pressurized Pneumatic System to Storage Silo	Convert Pressurized Pneumatic Fly Ash Transport System to Vacuum System.	None
Green	Sluiced to Pond	Sluiced to Pond	Sluiced to Pond	Pressurized Pneumatic System to Storage Silo	Eliminate Ash Storage Ponds and Install Dewatering Equipment & Convert Pressurized Pneumatic Fly Ash Transport System to Vacuum System.	Maintain Piping System and Add Dewatering Equipment to Eliminate Pond Storage. Landfill waste product.
HMP&L	Sluiced to Pond	Sluiced to Pond	Sluiced to Pond	Vacuum Pneumatic System to HMP&L Silo & Pressure Pneumatic System to Green Silo.	Eliminate Ash Storage Ponds and Install Dewatering Equipment & Convert Pressurized Leg of Transport Piping to Green Silo to Vacuum System	Maintain Piping System and Add Dewatering Equipment to Eliminate Pond Storage. Landfill waste product.
Reid	Sluiced to Pond	Sluiced to Pond	Sluiced to Pond	Pressurized Pneumatic System to HMP&L Silo	Eliminate Ash Storage Ponds and Install Dewatering Equipment & Convert Pressurized Portion of System to Vacuum Pneumatic	Maintain Piping System and Add Dewatering Equipment to Eliminate Pond Storage. Landfill waste product.

Last page of Section 2.

3. PHASE II – IDENTIFICATION OF COMPLIANCE TECHNOLOGIES

3.1 EXISTING TECHNOLOGIES

The BREC units currently operate a number of pollution control technologies that can help to provide a means of regulatory compliance. The existing equipment is either sufficient to comply with the expected regulatory limits, or it may be applied in combination with other new technologies to provide the most cost effective approach. In some cases, the existing equipment has been demonstrated to be incapable of meeting the regulatory limits, in which case all new technology must be explored.

3.1.1 Air Pollution Control

As shown in Table 1-2 and Table 1-3, the BREC units have a variety of air pollutant control technologies implemented at the units across their fleet. All BREC units except Reid Unit 1 are equipped with wet flue gas desulfurization (WFGD) systems. All of the units except Reid RT are equipped with first generation low-NO_X burners. Coleman Units 1-3 and Wilson Unit 1 have overfire air. Wilson Unit 1 and Henderson Units 1&2 are equipped with selective catalytic reduction (SCR) systems for NO_X removal. Each BREC unit also has an electrostatic precipitator (ESP) installed (cyclone ESP for Reid 01) for filterable particulate removal. The capability of the existing air pollution control equipment was evaluated against the anticipated regulatory limits to determine whether these systems can comply. Details regarding existing technology effectiveness are discussed in Phase I of this report and included in Attachment 1 of this report. Exploration of new technologies and implementation of various upgrades to support the existing systems are discussed in detail in Sections 3.2 and 4 of this report.

3.1.2 Intake Structure Impingement Mortality and Entrainment (316(b))

Currently, the maximum through-screen velocity of 0.5 fps at Wilson station meets the expected 316(b) requirements. However, the maximum through-screen velocities at Coleman and Sebree are not capable of meeting the expected 316(b) requirements. Screens at Coleman and Sebree are not currently equipped with any systems that reduce impingement mortality or entrainment sufficiently to meet the proposed regulation.

3.1.3 Coal Combustion Residual Handling

If the Subtitle C regulations are promulgated, significantly higher costs will be incurred because the products will need to be transplanted as hazardous waste, as described in Section 2.4. It would also be recommended that BREC convert any existing positive-pressure pneumatic ash transport systems to negative-pressure (vacuum) systems to avoid potential out-leakage. If the Subtitle D regulations are promulgated (i.e., CCR as non-hazardous waste), BREC units will incur additional landfill costs for fly ash and WFGD waste products due to Subtitle D requirements for lining of landfills and ongoing groundwater monitoring.

Although Subtitle C and Subtitle D make some provision for continued operation of on-site ash ponds, the current method of using the ash ponds to dewater the bottom ash material before loadout and trucking offsite is not considered to be practical for the following reasons:

- High cost of retrofitting the on-site ash ponds with the required composite liners and groundwater monitoring systems.
- Impact on station operations and outage time necessary for retrofit of composite liners into the ash ponds.
- The use of front-end loaders and/or drag chain equipment to dewater the ponds following installation of liners, which could result in damage to the required composite lining system.

As a result, conversion of the existing wet bottom ash sluicing systems to one of several dry bottom ash technologies is recommended and included as the study basis.

3.2 CANDIDATE TECHNOLOGIES FOR COMPLIANCE

This section highlights the potential control technologies for each of the CSAPR and proposed Utility MACT regulated pollutants and the proposed technologies for potential forthcoming CCR and 316(b) regulations. S&L screened the potential control technologies and identified the technologies that are the most practical to be implemented at the various BREC stations for compliance with the new regulations.

3.2.1 SO_2 and Acid Gas Control Options

3.2.1.1 SO_2 Control Technologies

3.2.1.1.1 Dry Sorbent Injection Technology

Dry sorbent injection (DSI) technology is a low-capital-cost option for controlling SO_2 emissions; however, DSI systems typically have much higher variable O&M costs than FGD systems. DSI uses a sodium sorbent, such as trona or sodium bicarbonate (SBC), to react with the SO_2 present in the flue gas. Trona and SBC are injected as a dry product into the flue gas, typically upstream of the air preheater (APH) for trona and downstream of the APH for SBC. The reagents then react with SO_3, HCl, and SO_2 in the flue gas. DSI technology has been proven to achieve overall SO_2 reductions up to 90% for low sulfur applications. However, unlike FGD, DSI performance is highly unit-specific and depends on several factors, including fuel sulfur content, temperatures at the injection locations, available residence times, and the type of particulate collector.

It is recommended that before installing a full-scale system, DSI technology be demonstrated on that particular unit to confirm the achievable performance and determine its effect on ESP performance.

3.2.1.1.2 Wet Flue Gas Desulfurization Technology

WFGD technology uses a lime or limestone slurry to react with the SO_2 present in the flue gas. WFGD systems consist of multiple levels of spray nozzles, where the alkaline slurry contacts the flue gas, and liquid tray level(s) that removes the SO_2. The slurry simultaneously quenches the flue gas as the water evaporates and reduces SO_2 emissions by reacting to form $CaSO_3$ and $CaSO_4$. WFGD technologies can typically achieve up to 98%–99% SO_2 removal with an outlet emission of 0.05 lb/MMBtu or less.

3.2.1.2 SO_2 Control Strategies

Based on review of the provided data and the anticipated CSAPR limits, only slight improvements from the BREC stations are required to meet the 2012 SO_2 Allocations. However, since Kentucky is part of the Group 1 compliance states (see Attachment 1 for details), significant improvements will need to be implemented to meet the 2014 SO_2 allocations. Except for Green Units 1 & 2, SO_2 emissions from all other BREC units are above their site-specific allocations and are candidates for SO_2 emission reduction improvements. For all units except Coleman, it is expected that the necessary CSAPR 2014 SO_2 reductions will result in unit emission rates below 0.20 lb/MMBtu, which would also allow for use of SO_2 emissions data as a surrogate for demonstrating compliance with the MACT acid gas regulations. Although emissions data for those units indicate that current HCl emissions are below the proposed MACT limits, this approach would eliminate the need for installation of HCl monitors to demonstrate acid gas compliance. Table 3-1 below provides a list of the various new technologies and equipment improvements that were explored for improved SO_2 control.

Table 3-1 — Candidate SO_2 Control Technologies

Unit	Technology	Comments
Coleman 1/2/3	Existing WFGD (Common)	Recent operational data indicate that the existing WFGD is operating at approximately 93.5% SO_2 removal, resulting in an annual emission of around 7,150 tons of SO_2 per year. Based on interviews with the Coleman plant staff, the WFGD system has recently been operated using a lower quality limestone. This indicates that the existing system performance can readily be improved.
	Increase L/G	Increasing the liquid-to-gas ratio of the current WFGD by upgrading the existing pumps and nozzles will significantly increase the efficiency of the scrubber. In discussions with the WFGD manufacturer, it was acknowledged that an increase in liquid to gas flow of approximately 20% would result in SO_2 removal efficiencies near 98%.
	Additives	Either dibasic acid or sodium formate could be used to improve removal efficiencies of the current FGD system.
Wilson	Existing WFGD	Currently Wilson has a Kellogg horizontal scrubber in service. Recent operational data suggest the absorber is operating at approximately 91% SO_2 removal efficiency with use of dibasic acid (DBA) and sodium bisulfite, resulting in an annual emission of around 9,450 tons of SO_2 per year.
	Increase L/G	Increasing the liquid to gas ratio of the current WFGD by upgrading pumps and spray nozzles may result in removal rates low enough to satisfy the proposed emission limits. However, based on limited number of similar installed technologies and insufficient supporting data, it is recommended that flow modeling be conducted before implementation of this strategy.
	New Absorber	Replacement of the existing horizontal flow absorber vessel with a vertical flow absorber while maintaining use of the supporting reactant preparation systems. Increase in flue gas pressure drop across WFGD system and additional duct losses necessitate need for booster fans. New scrubber technology will allow for 99% SO_2 removal, which results in excess credits to be sold or shared amongst other BREC units.
Green 1&2	Existing WFGD	Unit 1 and Unit 2 have dual absorber, dedicated WFGDs, The existing WFGDs achieve high SO_2 removal efficiencies and are not a major contributor to BREC's overall fleet deficit. Current emissions are at approximately 3,300 tpy, which is below the proposed CSAPR 2014 allocations. Furthermore, recent stack test data show an SO_2 emission rate of 0.186 lb/MMBtu for Unit 1 and 0.139 lb/MMBtu for Unit 2, which is below the anticipated MACT limit of 0.2 lb/MMBtu, allowing SO_2 emissions data to be used as a surrogate for HCl emissions. It is anticipated that any additional modifications at green would not provide any substantial additional reductions.
HMP&L 1&2	Existing WFGD	Unit 1 and Unit 2 currently both have dedicated WFGDs. Currently, operational data suggest that they are achieving SO_2 removal efficiencies of approximately 93% (Unit 1) and 90% (Unit 2). Based on these removal rates and the recent operational data, emissions will be around 2,227 tpy (Unit 1) and 2,745 tpy (Unit 2).

Unit	Technology	Comments
	Increase L/G	Currently, the absorbers at HMP&L operate with one out of two recycle pumps in service. Data collected from the plant where both recirculating pumps are used show that SO_2 removal efficiencies of >97% can be achieved. However, the dual pump operation inherently leads to loss of system redundancy and increased pressure drop across the absorber in an already fan-limited system. As a result, increasing the liquid-to-flue gas ratio at HMP&L will also require tipping of the existing ID fans, new fan motors, and installation of a third recycle pump to be used as a spare for each unit.
	Additives	Either dibasic acid or sodium formate could be used to improve removal efficiencies of the current FGD system.
Reid 1	Existing	Currently, Reid 01 has no SO_2 control technologies installed at its facility. As currently configured, the unit emits approximately 4,560 tpy of SO_2. The historical emissions from Reid 01 show that continuing current operation will significantly contribute to BREC overall fleet-wide SO_2 deficit.
	New WFGD	Installation of a new WFGD system at Reid 01 would result in operational compliance with the proposed regulatory emission limits. Currently available FGD technology has been proven to achieve removal efficiencies of >99%.
	Trona Injection	Injection of Trona into the flue gas stream has been proven to provide up to 80% SO_2 removal in some cases. However, due to the high volumetric flow required to produce such removal efficiencies, significant increase in ESP loading is to be expected, resulting in PM emission rate increases beyond allowable limits without significant ESP modifications or installation of a baghouse.

3.2.2 SO_3 Mitigation

The coupling of SCR and WFGD systems has resulted in unintentionally increasing the production and emission of sulfuric acid mist. The vanadium in SCR catalyst aids in the oxidation of SO_2 to SO_3. This results in a fraction of the SO_2 in the flue gas being oxidized to SO_3. When this SO_3 cools along with the flue gas, both going through the air heater and the WFGD, it combines with moisture, creating H_2SO_4 (sulfuric acid). The sulfuric acid mist forms into sub-micron aerosols that are not efficiently collected by conventional WFGD systems, and consequently pass through the FGD system and into the chimney. The resulting emission of sulfuric acid creates a blue plume and can bring a unit out of compliance for total particulate since the proposed MACT rule includes condensable particulate.

3.2.2.1 SO_3 Control Technologies

Removal of SO_3 from flue gas is accomplished by using a DSI system. The dry sorbent that is used for SO_2 capture (hydrated lime) can also capture SO_3 by injecting the sorbent into the flue gas stream after the air heater. The solid is then removed from the flue gas by use of a particulate removal system, such as an ESP or baghouse.

It has also been shown that it is cost effective to control the SO_3 with sorbent injection, which thereby reduces the activated carbon requirements for mercury removal. Less carbon is needed after reducing the SO_3 because SO_3 competes with Hg for adsorption in the pores of the activated carbon. However, the effect of sorbent injection on ESP performance should be tested before implementation.

3.2.3 NO_X Control Options

3.2.3.1 NO_X Control Technologies

3.2.3.1.1 Selective Catalytic Reduction Technology

In an SCR system, ammonia (NH_3) is injected into the flue gas at the exit of the economizer. This ammonia in the flue gas reacts with NO_X in the presence of a catalyst to form nitrogen and water. The catalyst enhances the reaction between NO_X and ammonia and results in high NO_X removal efficiencies with an economical use of the ammonia. The injected ammonia is adsorbed on the catalyst surface in the SCR reactor and reacts with the oxygen and NO_X present in the flue gas. SCR systems can typically achieve 80%–90% NO_X removal with outlet emissions of as low as 0.04 lb/MMBtu.

3.2.3.1.2 Selective Non-Catalytic Reduction Technology

The SNCR process uses a urea-based reagent that reacts with NO_X in the flue gas to form elemental nitrogen and water vapor. The driving force of the reaction is the high temperature within the boiler. Urea solution is injected into the boiler at locations in the unit that provide optimum reaction temperature and residence time. SNCR systems can typically achieve 15%–40% NO_X removal depending on the baseline NO_X emissions, injection temperature, residence time, and other factors.

3.2.3.1.3 State-of-the-Art Low-NO_X Burners (Third Generation)

Low-NO_X burners (LNBs) reduce emissions of NO_X by separating the air flow into two paths, staging the mixing of coal and air. This provides a fuel-rich region for char combustion, longer flames, and lower peak flame temperatures that helps limit the formation of thermal NO_X. LNBs generally use dual air registers in parallel to delay the mixing of air with coal injected through a coal nozzle in the center of the burner. While LNBs reduce NO_X, they may result in higher levels of unburned carbon as a result of incomplete combustion that occur from the staging of mixing. LNBs do not affect the emissions of other pollutants such as CO_2, SO_2, or particulates.

3.2.3.1.4 Overfire Air,, ROFA® and ROTAMIX ®

Conventional overfire air (OFA) systems cause intense turbulence in the upper part of the boiler and can effectively mix oxygen and flue gas in the upper furnace for effective completion of combustion and an overall reduction of NO_X. Selective non-catalytic reduction (SNCR) also may be combined with LNB or OFA to provide deeper emissions reductions for moderate capital investment. Addition of SNCR with an OFA system will add urea or ammonia to some or all of the OFA ports so that the ammonia is conveyed into the furnace where the temperature is most favorable for NO_X removal. Nalco-Mobotec USA refers to their combination of OFA/SNCR as ROFA (Rotating Overfire Air)/ROTAMIX, which is a patented technique by the developers of ROFA for mixing of NO_X-reducing chemicals in the furnace through their ROFA nozzles. In this technique, the same kind of asymmetrical air nozzles used for ROFA are used in the ROTAMIX technique. A booster fan is generally necessary for the OFA depending upon forced-draft fan characteristics. (A minimum of 8 in. H_2O pressure between the windbox and the upper furnace needs to be available.)

3.2.3.1.5 FMC PerNOxideSM Process

The PerNOxide process has been proposed by FMC and URS for a full-scale demonstration/installation of this NO_X removal process at Green Unit 1 or 2. The PerNOxide process involves the injection of hydrogen peroxide into the flue gas between the economizer and the air heater. The hydrogen peroxide oxidizes the nitric oxide (NO) into other nitrogen-oxygen compounds. Once these nitrogen compounds are formed, they must be captured to effectively remove them from the flue gas stream. Based on the estimates by URS/FMC of collection in the Green lime-based FGD system, there would be between 55% and 65% NO_2 removal in the scrubbers.

3.2.3.2 NO_X Control Strategies

Based on review of the provided data and the CSAPR limits, a reduction in fleet-wide NO_X removal is required. Except for Wilson and the Henderson units, all the other BREC units are large contributors to the BREC CSAPR emissions deficit and are preferred candidates for NO_X control technologies. The Green and Coleman units offer the greatest potential reduction improvements to meet the upcoming regulations. Overall fleet-wide NO_X emissions will need to be reduced by nearly 16% to meet BREC's 2014 allocations by means of various improvements through new equipment and retrofits. Table 3-2 below provides a list of the various new technologies and equipment improvements that were explored for improved NO_X control.

Table 3-2 — Candidate NO_X Control Technologies

Unit	Technology	Comments
Coleman 1/2/3	Existing LNB & (R)OFA	Coleman Units 1, 2, and 3 are all equipped with first-generation low-NOx burners. Units 2 and 3 have a conventional OFA system while Unit 1 has a second-generation ROFA system. With the currently implemented technologies, Units 1, 2, and 3 emit approximately 1,860, 1,590, and 2,050 tpy respectively and are a major contributor to the overall fleet-wide deficit.
	LNCFS III	Installation of the latest generation of Low-NOx Concentric Firing System (LNCFS) is expected to reduce formation of NOx more effectively than the current system. Supplementary technologies would need to be installed in conjunction with the LNCFS to reach acceptable emission rates.
	SNCR	Installing the latest SNCR technology will provide a significant improvement compared the currently installed technology. NOx reductions of approximately 20% can be expected for the Coleman units with the implementation of an SNCR. Although the units are short of their 2014 allocations by 47%–56%, the reduction significantly helps the overall fleet-wide allocation deficit.
	ROTAMIX (Unit 1)	ROTAMIX is a second-generation SNCR technology that can provide similar NOx reductions as the traditional SNCR but requires fewer modifications for units that have ROFA systems in place. Emission reductions of 20% can be expected with this technology.
	SCR	SCR could provide the Coleman units with significant reduction in NOx emissions. However, based on plant walk downs conducted early in the project, there appears to be limited available space for the technology's anticipated footprint, thus increasing overall project cost. Furthermore, because of the existing control technologies installed, the overall benefit of an SCR installation would not be as great as other units.
Wilson	Existing LNB/OFA/SCR	Wilson currently has multiple technologies implemented for NOx control including SCR. Based on their existing systems and recent emission data, it is expected that Wilson will not require any additional upgrades to meet the anticipated emission limits.
	Advanced Low-NOx Burners	In discussions with plant staff, it was noted that Wilson currently spends a large amount of O&M budget on maintaining their existing burners. Upgrade to state-of-the-art low-NOx burners will provide some O&M relief, but is not expected to provide a reduction in NOx emissions.
HMP&L 1&2	Existing LNB/SCR	The existing low-NOx burners and SCR currently installed at HMP&L Units 1 and 2 are producing removal efficiencies adequate to meet the projected 2014 limits. If operation continues in a manner similarly to the baseline time period, BREC can expect excess NOx credits of approximately 520 tpy as compared to their 2014 allocations that can be shared to offset other facilities' deficits. Plant staff noted that there are a number of issues causing excessive O&M efforts and costs with the existing burners.
	Advanced Low-NOx Burners	Although it is not anticipated BREC will significantly reduce NOx emissions by installation of third-generation low-NOx burners, the will provide relieve from their current O&M issues and may potentially offer some reduction in emissions.
Green 1&2	Existing LNB	Both Green units are equipped with first generation low-NOx burners. With the currently implemented NOx control technology, Units 1 and 2 emit approximately 2,050 and 2,170 tpy respectively and will need to reduce emissions significantly to comply with their anticipated allowance.
	SNCR	Installing the latest SNCR technology will provide an improvement compared the technologies installed currently at Green. NOx reductions of approximately 20% can be expected for the Green units with the implementation of an SNCR.

Unit	Technology	Comments
	SCR	SCR would provide sufficient reduction in NO_x emissions and would result in excess credits to be shared amongst the other BREC units. Typical removal efficiencies for units comparable to Green are around 85%. Based on current operational data, installation of SCR at both Green units would result in an excess of approximately 2,250 tpy compared to the 2014 allocations. This excess would cover nearly all of the BREC fleet's shortage for 2014.
	Advanced Low-NO_x Burners with OFA	Upgrade to state-of-the-art low-NO_x burners along with OFA will provide some O&M relief as well as provide an approximate reduction of 432 tpy in NO_x emissions.
Reid 01	Existing LNB	Reid 01 is equipped with first-generation low-NO_x burners. With the currently implemented NO_x control technology, the unit emits approximately 5,066 tpy and would need to reduce emissions significantly (≈69%) to comply with their 2014 allowance.
	SNCR	Installing the latest SNCR technology will provide a significant improvement compared the NO_x technologies installed currently at Reid 01. NO_x reductions of approximately 20% can be expected for the unit with the implementation of an SNCR system.
	SCR	SCR would provide sufficient reduction in NO_x emissions and would result in excess credits to be shared amongst the other BREC units. Typical removal efficiencies for units comparable to Reid 01 are around 85%. Based on current operational data, installation of SCR at Reid 01 would still result in a shortage of credits compared to the 2014 allocations.

3.2.4 PM Control Options

3.2.4.1 PM Control Technologies

3.2.4.1.1 Electrostatic Precipitator Upgrades

There are several available ESP upgrades which may be capable of reducing the filterable PM emissions from the existing ESPs. The potential ESP upgrades include the following:

- Installation of high frequency transformer-rectifier (TR) sets
- Rebuilding the ESP internals
- Adding an additional collection field to the ESP
- Converting part of the ESP to a baghouse (COHPAC II)

After reviewing the filterable PM emission rates from the BREC ESPs and based on S&L's engineering experience it was determined that upgrades to the existing ESP will achieve the required performance.

3.2.4.1.2 Dry Sorbent Injection for Condensable Particulate Matter

A significant contributor to condensable particulate matter is sulfuric acid (H_2SO_4). Dry sorbent injection (DSI) technology (previously explained as an SO_2 control technology) is the current industry standard to control acid gases including H_2SO_4; therefore, it may be a potential control technology for condensable PM emissions as a means of reducing the total PM. The use of DSI for compliance with the proposed Utility MACT limits for total PM is entirely dependent on the makeup of condensable PM which is currently unknown. Several sorbents are used for condensable PM control in the Utility Industry, these being Trona, sodium bicarbonate, and hydrated lime. Although hydrated lime is not as reactive as the sodium based sorbents (Trona and sodium bicarbonate) it will not affect the character of the fly ash being collected or the disposal of wastes, fixated or otherwise. In addition, BREC has familiarity with hydrated lime injection as it has been used for acid mist control for several years at the Wilson Station.

3.2.4.1.3 Baghouse Technology

There are several forms of baghouse technology which may be installed to achieve the required reduction in filterable PM emissions; these include:

- Converting part of the ESP to a baghouse
- Converting the existing ESP to a baghouse
- Adding a polishing baghouse
- Replacement of the ESP with a full baghouse

For those units that do not appear to be in compliance with the proposed Utility MACT limits for PM, an alternate approach to ESP upgrades or DSI may be required. If ESP upgrades or DSI are not capable of reducing emissions to below the Utility MACT limit, the unit will be required to install a baghouse. Baghouse technology would be capable of meeting a filterable PM outlet emission rate of 0.01-0.012 lb/MMBtu. It is not foreseen that the BREC units will require a baghouse to meet the anticipated MACT TPM emissions limits.

3.2.4.2 Particulate Matter Control Strategies

With the existing electrostatic precipitators and WFGD systems in service at the various BREC units, PM emissions are currently below the anticipated limits at the Green and Wilson facilities. TPM emission data collected for HMP&L, Reid 01 the Coleman Units shows that additional control or upgrade of the existing control systems will be required. Furthermore, because of the technology choices being considered to eliminate other pollutants (ACI, DSI, etc.) it is anticipated that modifications to the existing particulate controls will also be required for units that are currently below the 0.030 lb/MMBtu total PM limit and will be determined on a case-by-case basis based on overall required system upgrades.

3.2.5 Mercury Control Options

3.2.5.1 Mercury Control Technologies

When coal is combusted in a boiler, the mercury contained in the coal is released predominantly in three forms; particulate Hg, ionic (or oxidized) Hg, and elemental Hg. The quantity of each form of Hg that develops during combustion depends on a number of factors, including other constituents of the coal itself, such as the halogen content. The various types of mercury formed are called its speciation.

The speciation of mercury plays a significant role in the ease of its capture. The conversion of elemental mercury to oxidized mercury depends upon several factors;

- Cooling rate of the gas,
- Presence of a catalyst such as those found in an SCR,
- Presence of halogens (chlorides, bromides, fluorides, etc.) or SO_3 in the flue gas,
- Amount and composition of fly ash, and
- The presence of unburned carbon.

Particulate mercury exists in solid form and is removed to a significant degree by conventional particulate control equipment such as ESPs and baghouses.

Elemental mercury is insoluble in water and is generally not removed in normal particulate control devices or in an FGD system. In contrast to elemental mercury, oxidized mercury is highly water soluble. Wet FGD systems downstream of particulate control devices readily capture oxidized mercury.

Some technologies for mercury removal involve converting elemental mercury to water soluble, ionic mercury for capture in a downstream FGD. Others involve adsorption of mercury on activated carbon by the injection of carbon in the flue gas.

3.2.5.1.1 Fuel Additives

Halogen fuel additives, such as calcium bromide, are a low capital cost option for improving mercury capture for units equipped with mercury control technologies that have a low proportion of oxidized mercury to elemental mercury. Bituminous fuels, similar to that burned at BREC facilities, typically have higher (than PRB fuels) chloride concentrations in the coal, which inherently help in oxidizing elemental mercury. Halogen additives can be added to the coal (target approximately 100 ppm bromide in coal) to increase the amount of oxidized mercury to greater than 90% of the total mercury present in the flue gas. The oxidized mercury is more readily captured by carbon in the flue gas; in addition, lower injection rates or less expensive non-brominated carbon may be used to capture the mercury downstream.

It is recommended that before installing a permanent fuel additives system, a portable system be used to test the effect these additives have on the overall mercury capture and potential re-emission.

3.2.5.1.2 Activated Carbon Injection

Activated Carbon Injection (ACI) is a proven technology for mercury (Hg) reduction downstream of coal-fired boilers. ACI technology can achieve >90% reduction in total Hg. ACI has been proven effective in removing both oxidized and elemental mercury. The drawback to ACI use is the high cost of activated carbon.

Some flue gas constituents, especially SO_3, reduce the effectiveness of ACI. Operation of a DSI system before an ACI system may be required to reduce the SO_3 concentration to 3–5 ppm to improve the overall ACI effectiveness while maintaining high enough SO_3 concentrations to aid ESP performance. In addition, fuel additives can be combined with non-brominated carbon to potentially provide the required removal efficiency while using less carbon.

It should be noted that with the addition of an ACI system, the particulate loading to the ESP will be increased and that S&L recommends testing of the PM emissions with ACI to determine if any upgrades to the ESP are necessary.

3.2.5.2 Mercury Control Strategies

Mercury emissions testing at the BREC units indicate that HMP&L 1 & 2 currently meet the proposed MACT standard with no additional mercury controls. Mercury from units Coleman 1-3 and Green units 1-2 must be reduced by approximately 53% to 66% to meet the proposed MACT emission limits. Mercury emissions from Wilson 1 must be reduced by nearly 32% to meet the proposed MACT standard. Mercury from Reid 01 must be reduced by approximately 80% to meet MACT standard. Mercury control options capable of achieving the required removal efficiencies include Fuel additives to promote mercury oxidation and mercury capture in the units' ESP/FGD control systems, and activated carbon injection control system.

3.2.6 Intake Structure Impingement Mortality and Entrainment (316(b))

3.2.6.1 316(b) Compliance Technologies

Although 316(b) regulations have yet to be finalized there are several equipment suppliers that are actively developing various technological means of meet the proposed rule. Although none of the technologies discussed below have been implemented beyond test applications, there are specific operational characteristics that make certain technologies more viable than others at a particular site. Technologies that either reduce through-screen velocity to 0.5 fps or less or provide a means of returning impinged fish back to the supply body of water within the acceptable mortality rates are actively being considered by utilities for compliance along with other alternative means.

3.2.6.1.1 Replacement Screens with Fish Buckets / Return Systems

Test installations of traveling screen designs that are equipped with fish bucket and fish return systems have been shown to reduce impingement mortality to levels that would comply with the proposed regulations. It is expected that the entrainment portion of the standard can be met via the studies and testing described in Section 2.2 of this report. The traveling screens can be operated continuously, and any fish impinged on the screen will be lifted up in a horizontally mounted fish bucket and discharged safely into a trough as the bucket rotates up and over the top of the screen. Low pressure water provides for safe flushing of the fish back into the river. The scope of work involved in a traveling screen replacement such as this involves the removal of the existing traveling screens, replacement with new screens equipped with fish buckets and a fish return system, electrical and controls installation, and 316(b) approval Testing. Significant structural modifications are not expected since the new screens would be designed to fit into the existing screen guide channels of the intake structure(s).

3.2.6.1.2 Rotating Circular Intake Screens with Fish Pump

Rotating circular intake screens are designed to meet the 316(b) requirements by safely returning impinged fish to the river through the use of fish pumps. It is expected that the entrainment portion of the standard can be met via the studies and testing described in Section 2.2 of this report. These screens would be designed to match the size of the mesh in the existing traveling screen intake wells, or this mesh could be reduced somewhat if the entrainment compliance studies indicated this is necessary.

The scope of work involved in a rotating circular screen installation retrofit includes the removal of the existing traveling screens, existing intake structure concrete and channel modifications to accept the new screens, screen installation including fish pump and return systems, electrical and controls installation, and 316(b) approval testing

3.2.6.1.3 Cylindrical Wedgewire Screens

Another approach to meeting the target reduction in impingement is to retrofit the existing intake structure with cylindrical wedgewire screens in order to reduce the intake entrance velocity to a maximum of 0.5 fps. The existing intake structure would be modified to take suction through large screen headers that extend out into the river.

For river installation such as those being reviewed for BREC, the screen will require periodic cleaning due to debris buildup. To accomplish this, a compressed air system installed near the intake structure releases a large volume of compressed air to backflush any debris from the screen surface back into the river. The river current flowing across the cylindrical wedgewire aids in transporting the backflushed debris downstream away from the intake structure, helping to avoid re-entrainment onto the screen surface. Once a screen mesh size is selected, it is difficult to retrofit a different screen mesh size to address a new potential entrainment portion of pending legislation, since the surface area and size of the screens is determined based on mesh size.

The scope of work involved in a cylindrical wedgewire installation involves significant modification of the existing intake structure to accept the cylindrical wedgewire headers, mounting of cylindrical wedgewires underwater, including any required support structures, backflushing compressed air system installation, electrical and controls installation, and 316(b) approval testing.

3.2.6.1.4 Conversion to Closed Cycle Cooling

Closed-cycle wet cooling systems can reduce cooling water intake volume, and consequently IM&E impacts, by approximately 95% compared to once-through cooling, and would most certainly meet all anticipated 316(b) performance standards. Closed-cycle wet cooling will effectively reduce entrainment and, assuming the though-screen velocity of the make-up water intake structure does not exceed 0.5 fps, will effectively reduce impingement mortality. In addition to special constraints at Coleman and Sebree, when evaluating the feasibility of a retrofit closed-cycle wet cooling system, consideration must be given to collateral environmental impacts, including air emissions, visual impacts, and noise impacts. Due to the size of the cooling tower structure and their visible vapor plume, cooling towers have a visual and aesthetic impact on the surrounding area. Noise emissions during operation of the cooling tower must also be considered, particularly with mechanical draft cooling towers.

Based on a review of the intake velocities at Coleman and Sebree, which can potentially reach 2.4 fps, this study considers installation of a full-sized mechanical-draft cooling tower since even a partial-capacity closed-cycle system would be nearly the same size to reduce intake velocities by the required margin. Due to large capital and O&M costs when compared to the other available compliance technologies this option was not considered further.

3.2.6.1.5 Other Technologies - Behavioral Barriers

Behavioral barriers reduce impingement by triggering a behavioral response in fish causing them to avoid the intake flow. Behavioral barriers have been used with varying success, as behavioral responses are a function of fish species, age and size, as well as environmental factors at specific locations. Recent tests using advanced acoustic barrier technology have successfully reduced alewife impingement at intake structures located in the Great Lakes. Although behavioral barriers, including light and sound, have been used with some success at certain locations, studies would have to be conducted to determine the effectiveness of sound, light, and/or other behavioral barriers at Coleman and Sebree stations. Although it provides a potentially low-cost solution, behavioral barriers will not be considered for further screening and cost estimate purposes since extensive local testing would be needed to establish this as a best technology available.

3.2.6.2 316(b) Compliance Strategy

The proposed regulations for 316 (b) do not mandate a cooling tower as the required technology selection. As such, this study will evaluate practical, relatively low cost screen options for installation at the Coleman and Sebree stations. Technologies described above that will be considered for further screening and cost estimating evaluation are as follows:

- Replacement Screens with Fish Buckets / Return Systems
- Rotating Circular Screens with Fish Pump
- Cylindrical Wedgewire Screens

3.2.7 Coal Combustion Residual Options

3.2.7.1 Coal Combustion Residual Technologies

All BREC units (except Reid 01) are equipped with WFGD and fly ash waste product handling and disposal operations. These systems can continue as-is, although potentially significant (Subtitle C) or minor (Subtitle D) increases in handling and disposal costs may occur. With exception of Wilson which currently has dry bottom ash disposal with an existing SSC, new bottom ash technologies evaluated are as follows:

3.2.7.1.1 Submerged Scraper Conveyor

A submerged scraper conveyor (SSC) provides for removal of the bottom ash by transporting the bottom ash up an inclined dewatering ramp before discharging into a bottom ash enclosure for removal by front end loader and trucks. If the bottom ash is going to be stored in a silo before disposal, then the SSC discharges through a crusher, then the crusher discharges to a vertically inclined drag-type chain conveyor or belt conveyors for transport to the bottom ash storage silo.

A closed loop recirculating system is used for supplying cooling water to the chain conveyor trough. The recirculating system includes a holding tank, heat exchanger, pump and water treatment (pH control) system. The horizontal section of the drag chain conveyor is adequate for three (3) hours of storage during periods of peak bottom ash production rates. The conveyor flights are designed with replaceable abrasion resistant wear strips to allow for wear resistance on both the conveying and return cycles. The conveyor flights are moved by two strands (or a double strand) of carburized chain. New pumps and electrical equipment would be housed in new buildings located by the SSCs.

Depending on the space constraints underneath the boiler, the SSC may be either mounted directly under the hopper or it may be mounted remotely. The remote submerged scraper conveyor (SSC) system provides for removal of the bottom ash from the boiler hopper(s) using the existing sluice system to transport the ash to the SSC, before discharging into a bottom ash enclosure for removal by front end loader and trucks. Based on a review of the plant general arrangement drawings and site walkdowns, the available space adjacent to the boiler buildings at the BREC stations is limited due to existing structures. As such, a remote SSC installation is considered as the basis for this study.

3.2.7.1.2 Dry Ash Cooler / Conveyor

The main component of the dry ash conveyor system is the extractor, which is designed to operate in harsh conditions including exposure to high temperature and shock loads caused by the fall of large clinkers. The extractor is connected to the boiler throat through a refractory-lined hopper or a transition chute, which provides a volume for temporary ash storage. The hopper is available with bottom doors which can be closed to isolate the extractor and for ash storage. The hopper or transition chute is connected to the boiler throat by a high temperature mechanical seal that allows for boiler expansion. The key element of the extractor is the hardened steel belt conveyor, which receives and extracts bottom ash falling from the boiler. The belt is enclosed inside the sealing casing of the extractor.

During the conveying of ash on the belt, ash is cooled by a small, controlled amount of ambient air that flows by natural draft into the casing through inlet valves. In addition the air provides oxygen to the unburned ash allowing a more complete combustion and return of heat to the boiler. Data from existing installations indicate reverse air flow does not disturb the combustion process and does not influence NO_X formation. From the extractor, the cooled ash is discharged into a crusher, which reduces the large ash clinkers to a size suitable for conveying to a silo. Any ash fines that fall on the casing floor are swept off by the spill chain, a small scraper conveyor installed under the belt.

There are currently only two manufacturer's of the dry ash conveyor, Magaldi Industries and United Conveyor Corporation (UCC). This system can only be used when installed directly under the boiler hopper(s). Based on a review of the BREC site general arrangements and site walkdowns, there does not appear to be sufficient space on either side of the boilers at Coleman, HMP&L and Green for installation of a dry bottom ash cooler / conveyor.

3.2.7.1.3 Dewatering Bin System

This type system is also referred to as a closed-loop recirculation system which converts a wet sluice system into a "dry" ash system without change to the existing bottom ash hopper. A complete recirculation system replaces the ash pond with dewatering bins which separates the water and ash, a clarifying (settling) tank and surge (storage) tank and associated pumps and piping. The dewatering bin is designed to remove and drain water from solid materials that have been pumped into the bin in a slurry form. The dewatering bin, a cylindrical steel tank with a conical bottom, is custom sized for various material tonnage capacity requirements. Typically constructed of mild steel plate, the bin can also be constructed with alloy materials for exceptionally corrosive conditions.

The clarifying (settling) tank, is a cylindrical steel tank with a conical bottom, is used to remove the remaining fines from the water, return the fines to the dewatering bin and send the decanted water to the surge tank. The settling tank is custom sized for various material tonnage capacity requirements. Typically constructed of mild steel plate, the bin can also be constructed with alloy materials for exceptionally corrosive conditions. The surge (storage) tank, is a cylindrical steel tank with a conical bottom that is used to store the decanted water and provide a suction head for the recirculation system return pumps. The surge tank is custom sized for various material tonnage capacity requirements. Typically constructed of mild steel plate, the bin can also be constructed with alloy materials for exceptionally corrosive conditions.

This system reuses the conveying water and only requires a small amount of make-up water. The recirculation system is ideal when water supplies are available and minimal outage time is required to make the conversion. The ash is unloaded from the dewatering bins into transport vehicles for disposal.

3.2.7.2 Coal Combustion Residual Strategies

Data collected during site walkdowns and discussions with plant staff indicate that modifications will be necessary at Coleman, Wilson (pneumatic transport modifications for Subtitle C only), Green, Reid 01 and the HMP&L units. Elimination of the existing ash ponds at Coleman, Green, Reid 01 and HMP&L is expected with either Subtitle C or D. The technologies discussed above will be considered for further screening and cost estimating evaluation.

3.3 OTHER COMPLIANCE STRATEGIES

3.3.1 Purchase of Emission Allowance Credits

The purchasing of emission allowance credits may be an economically justifiable compliance strategy, or part of a compliance strategy involving lower cost equipment or system than would otherwise be required. This study evaluates this approach by estimating the future cost of credits under the proposed regulations, and then reflecting these costs as operating expenditures that can be compared with the capital and O&M costs associated with new technology installation. It should also be noted that such a strategy is highly sensitive to credit market costs and availability and may not be economically justifiable on a long-term basis.

3.3.2 Conversion to Natural Gas

In addition to the compliance methods explored for various pollutants above, there is also the possibility of converting a coal-fired boiler to operate on natural gas. Conversion to natural gas would greatly reduce SO_2 emissions and also exclude the EGU from any potential MACT compliance. NO_X emissions would also be reduced from uncontrolled levels by approximately 40%. Due to lack of slagging, tube temperature limitations and other inherent design differences between natural gas and coal-fired boilers, it is typical that a 20% derate must be applied. Furthermore, modifications to the existing burners and installation of a flue gas recirculation system should be implemented to improve overall system performance and reduce NO_X emissions. Because of limited natural gas supply infrastructure near several of the BREC facilities, conversion was considered to only be viable at Sebree, specifically at Reid 01 and the Green Units. If additional supply is required for conversion of those units, BREC has indicated that an existing main trunkline is within approximately five (5) miles of the Sebree Station.

3.3.2.1 Reid 01

Half of the burners at Reid 01 were previously retrofitted with new natural gas burners and a natural gas supply fuel system. Based on interviews with plant staff, the system has never been permitted for operation. Although most of the infrastructure is in place, it is recommended that the existing system be inspected and tested before putting into operation. If a heat input near the baseline is maintained, Reid 01 should expect nearly untraceable SO_2 emissions and NO_X emissions reductions of approximately 220 tpy. The nearly 5,000 tpy reduction in SO_2 emissions would be available to the other BREC units to aid in achieving overall fleet-wide compliance.

3.3.2.2 Green 1 & 2

The Green units are the second most appropriate candidates for natural gas conversion. For each unit conversion, BREC can expect an approximate reduction of 1,400 tpy of SO_2 and 1,000 tpy of NO_X emissions provided a heat input similar to the baseline is maintained. It should also be noted that if BREC were to decide to convert either or both of the Green units for natural gas operation, an additional gas supply line would need to be routed from the existing off-site supply header to support the increased demand.

3.3.3 Retirement of Existing Units

Unit retirement is another potential strategy for compliance with the various EPA regulations. By retiring an existing unit, BREC will continue to receive that unit's CSAPR credit allocations for four years after the unit's last date of operation. Once the four year time period has elapsed, BREC will no longer have access to those credits and will have to adjust remaining plant operations to meet the reduced fleet-wide limits.

Because Reid 01 has minimal NO_X and SO_2 controls in place and it is one of BREC's smallest units, it becomes the best candidate for such a strategy. The unit's overall relative contributions to BREC's CSAPR deficit are larger than the other units and would require improvements to both SO_2 and NO_X controls. Being that the unit is 72 MW it also poses less of an impact to overall fleet-wide capacity than potentially retiring other units. If Reid 01 were retired, BREC would reduce their fleet-wide SO_2 and NO_X emissions by 5,066 tpy and 512 typ respectively and could use those to offset other station emissions.

Last page of Section 3.

4. PHASE III – TECHNOLOGY SCREENING AND SELECTION

4.1 SO_2 AND ACID GAS CONTROL OPTIONS

4.1.1 Existing SO_2 and Acid Gas Controls

All Big River Units except Reid 01 are equipped with WFGD air quality control systems. Based on their present operation the BREC fleet with the exception of Wilson and Reid 01 will meet their station specific 2012 allocations limits. Fleet-wide, BREC needs to reduce its yearly baseline SO_2 emissions by 3% (808 tons) to comply with the 2012 CSAPR allocations. A much greater fleet-wide reduction of 50% (13,643) is needed compared to the baseline emissions of 27,286 tpy to comply with the 2014 CSAPR limits. As stated in Section 3.2.1, it is anticipated that the SO_2 emission rates resulting from modifications at some BREC units will be at or below 0.20 lb/MMBtu which will allow SO_2 stack emissions data to be reported as a surrogate for compliance with the proposed acid gas MACT limits. Units above the SO_2 limits will require HCl monitors for compliance.

Recent operational data from Coleman Units 1-3 suggests that the existing WFGD is operating at approximately 93.5% SO_2 removal, resulting in an average annual emission of around 7,150 tpy. CSAPR allowances for Coleman are 8,195 tons for 2012 and 3,526 tons for 2014. Similarly, current HMP&L data suggests a removal efficiency of 93% for Unit 1 and 90% for Unit 2 which implies emissions of 2,227 tpy and 2,745 tpy for Units 1 and 2 respectively. These levels are within the 2012 CSAPR emission limits of 2,518 tons and 2,997 tons but are above the 2014 allocations of 1,251 tpy and 1,289 tpy.

Green units 1 and 2 current average of 3,290 tpy, is adequate removal for 2012 CSAPR emission limit of 3,849 tpy along with 3,735 tpy for 2014. Similarly, data for Reid RT suggests average emissions of 5 tpy which will stay within compliance for 2012 limits of 11 tpy and 9 tpy for 2014.

Wilson currently uses a Kellogg-Weir horizontal scrubber and recent data approximates SO_2 removal efficiency at 91% resulting in an average annual emission of around 9,450 tpy which is significantly over the emission limit of 8,400 tons for 2012 and 3,614 tons for 2014. Reid unit 1 currently has no SO_2 control technologies implemented. The unit on average emits approximately 4,560 tpy and predictions increase emissions to 5,066 tpy for 2012. The 2012 CSAPR limits emissions to 508 tpy. Historical emissions predict that continuing current operations will significantly contribute to BREC' overall fleet-wide SO_2 emission deficit.

S&L reviewed the entire EPA information collection request (ICR) database covering HCl and HF emissions from coal fired power plants. All Big River Units except Reid unit 1 are equipped with both ESPs and WFGD air quality control systems which are capable of removing HCl and HF. It is expected that if WFGD SO_2 removal efficiencies of ~97% or higher are achieved, the HCl emissions will meet the EGU MACT requirements without any further modifications. Furthermore, current emissions of the Green units are below the anticipated MACT limit of 0.2 lb/MMBtu, which would allow SO_2 emissions to be used as a surrogate for HCl emission monitoring.

4.1.2 Improved Spray Nozzles and Increased Liquid-to-Gas Ratio

Increasing the L/G (Liquid to Gas Ratio) in the wet FGD provides an environment for higher SO_2 absorption from the flue gas by the increased amount of liquid spray. The additional liquid slurry spray provides more surface area contact for the flue gas to react with, resulting in further removal of SO_2.

Increasing the L/G in the HMP&L units would be implemented by running both recirculating pumps on each absorber. Installation of a third pump for each absorber will provide use as a spare for reliability purposes. Tests at HMP&L were performed and the data collected confirms the ability for two pump operation to increase SO_2 removal to ~97%. Averaged SO_2 baseline data showing average SO_2 removal of single pump operation from July, 2011 and test trial data showing operation of two recirculating pumps is shown in Table 4-1. Feedback from plant staff indicated that while the tests were being conducted with two pumps the ID fans were at maximum capacity and unstable due to the increase in pressure drop across the FGD. Because the unit experienced limited fan capacity, ID fan modifications, including tipping the fan blades and installing new motors, will be considered as part of this modification.

Table 4-1 — HMP&L Scrubber Pump Test Data

	Inlet (lb/MMBtu)		Outlet (lb/MMBtu)			
	Unit 1	Unit 2	Unit 1	Unit 2	Unit 1	Unit 2
Test	SO_2	SO_2	SO_2	SO_2	Removal (%)	Removal (%)
Single Pump	5.20	5.34	0.341	0.503	**93.5**	**90.3**
Dual Pump	5.50	5.51	0.127	0.162	**97.7**	**97.1**

The data from the testing confirms sufficient increase in SO_2 removal with the addition of the second recycle pump to comply with the anticipated 2014 CSAPR and 2015 MACT limits. SO_2 removal percentage increases, on average, from 93.5 to 97.7 in HMP&L Unit 1 and from 90.3 to 97 for Unit 2 based on the 24 hour testing with a second pump in service.

4.1.3 Additives

Organic acid additives have been known to improve the SO_2 removal efficiency in WFGD systems by about 5%. SO_2 efficiency improvements can generally be achieved with as low as 500 ppm acid in the absorber slurry. The most common organic acids used in WFGD applications are dibasic acid (DBA), Adipic acid, Formic acid, and Sodium Formate. The addition of organic acids will require capital investment in storage and injection systems. There will also be an annual operating cost associated with the additive addition. The Wilson station currently uses organic acid to enhance FGD performance.

4.1.4 New WFGD Absorber

The Wilson plant currently operates a horizontal scrubber system that is one of only six built. Four of the six scrubbers are currently being decommissioned or are no longer in operation. This is a result of their inability to achieve high SO_2 removal standards of current and future regulations, even with modifications. Replacing the existing horizontal flow absorber vessel with a vertical flow absorber is a proposed SO_2 control strategy due to the minimal probability of achieving higher removal efficiencies with the existing technology. Installation of a new vertical scrubber would increase overall removal from ~91% up to ~99%.

Unit 1 at the Reid station currently does not use any SO_2 control technologies. Installation of a new WFGD system at this station would result in operational compliance with the proposed regulatory emission limits. Currently available wet FGD technology has been proven to achieve removal efficiencies of up to 99%.

4.1.5 Natural Gas Conversion

Converting an existing coal-fired unit to natural gas almost eliminates SO_2 emissions. For instance, Reid 01 has a baseline annual emission of 5,066 tons and after a gas conversion would emit approximately 1 tpy. Similarly, converting Green 1 and 2 to natural gas would reduce their overall annual emissions by 1,870 tpy and 1,411 tpy respectively. Conversion usually requires installation of new burners and a flue gas recirculation system to improve boiler efficiency and typically necessitates a derate of the unit.

4.1.6 Other Recommendations

Because the three Coleman units share a common WFGD there are operational scenarios when the absorber is out of service and the operating units must bypass the absorber and discharge into existing unit specific stacks. This operational mode causes uncontrolled SO_2 flue gas to be emitted and increases the overall emissions of the plant. For instance, if the scrubber were to be out of service along with one of the three units and the other two units were operating in bypass at an 85% capacity factor for eight (8) hours, an estimated 66 tons of additional SO_2 would be released from those two units than if they were operating with the WFGD in service. Regardless of approach for reducing SO_2 emissions, BREC should conduct a condition assessment to determine methods of improving WFGD system reliability to reduce the likelihood and duration of WFGD outages. In addition, BREC may also want to consider implementing a planned and forced outage strategy that prevents WFGD bypass operation to prevent uncontrolled emissions.

4.2 SO_3 MITIGATION

It is recommended that DSI systems be installed for CPM capture purposes at all BREC units except for units that are potentially converting to natural gas. Installing a technology to reduce SO_3 concentrations in the flue gas can provide a number of benefits. The air preheater pluggage and duct corrosion downstream of the air preheater is an operational concern for the Big River units. These problems are most likely the result of high SO_3 concentrations in the flue gas. In addition, the removal of NO_X on the SCR is limited by the interaction of SO_3 with the ammonia slip. SO_3 reduction will also reduce CPM emissions which reduces TPM limits that are regulated by the EGU MACT. If activated carbon injection is used as a mercury reduction technology, SO_3 reduction can reduce activated carbon usage, since SO_3 competes with Hg for adsorption sites on the activated carbon.

4.3 NO_X CONTROL OPTIONS

4.3.1 Existing NO_X Controls

All BREC units are currently operating with first-generation low-NO_X burners. The Coleman and Wilson units are each equipped with over-fire air systems. Wilson and HMP&L units also have SCRs installed. With the current control technologies, the BREC fleet's annual emissions are approximately 12,074 tpy. The 2014

CSAPR NO_X emission limits for the fleet total is 10,142 tpy, which would leave BREC with a deficit of 1,930 tpy in NO_X credits.

The current low NO_X burners in combination with over fire air system (Unit 2-3) and rotating over fire air system (Unit 1) at the Coleman and HMP&L units do not achieve sufficient NO_X reduction to comply with 2014 CSAPR emissions requirements. If no additional NO_X removal is achieved, credits will need to be purchased to meet the future regulatory requirements. For the combination of Coleman units, NO_X credits would need to be purchased to cover the difference between the actual NO_X emissions. The total Coleman NO_X emission is estimated to be 5,488 tpy while the anticipated 2014 Phase II CSAPR emissions limit is 2,065 tpy. Based on EPA's distribution of credits, Coleman would be short 3,423 tpy when compared to the site Phase II allocations.

The current technology at the Green units does not sufficiently reduce NO_X emissions for the 2014 CSAPR limits. Units 1 and 2 emit approximately 2,050 and 2,170 tpy respectively, while their combined limit is 2,890 tpy. Green units will need to significantly reduce NO_X emissions to comply with their anticipated allowance or they will be forced to purchase over 1,300 tpy in NO_X credits. Reid units will also have to reduce their annual emissions of around 560 tpy by 69% to be within compliance for their anticipated 2014 limits of 166 tpy.

Currently, the HMP&L SCR in combination with low NO_X burners is providing enough NO_X removal to give BREC an emission surplus, thus does not need any modifications. The amount of potential excess NO_X credits available would be approximately 982 tpy. Wilson also operates low NO_X burners in combination with an SCR, which would provide a NO_X emission surplus of 1,711 tpy for the 2014 CSAPR limits.

4.3.2 Advanced Burners

The low-NO_X concentric firing system (LNCFS) was developed for tangentially fired systems. The advanced technology separates the fuel and air streams for the tangential fired arrangement. This system applied to the Coleman station would reduce emissions approximately 10% in comparison with their current LNBs. However, it is foreseen that supplementary technologies would need to accompany the LNCFS to reach acceptable emission rates.

The Wilson station already has first generation LNB, OFA, and SCR technology implemented and meets the anticipated emission limits. There are planned upgrades for implementation of third generation LNB to reduce

O&M costs. Similarly, the HMP&L units currently have LNB and SCR technologies implemented and meet the anticipated emission limits but have a planned upgrade to install third generation LNB to alleviate O&M issues. Installation of third generation LNB at the Wilson and HMP&L units are not anticipated to provide any substantial reduction in NO_X emissions.

4.3.3 FMC PerNOxideSM Process

The PerNOxide process has been proposed by FMC and URS for a full-scale demonstration/installation of this NO_X removal process at Green Unit 1 or 2. The PerNOxide process involves the injection of hydrogen peroxide into the flue gas between the economizer and the air heater. The hydrogen peroxide oxidizes the nitric oxide (NO) into other nitrogen-oxygen compounds including

- NO_2
- N_2O_5
- HNO_2
- HNO_3

with a series of reactions that includes

$$H_2O_2 + NO \rightarrow H_2O + NO_2$$

$$2H_2O_2 + 2NO_{2+} \rightarrow H_2O + 2HNO_3 + \frac{1}{2} O_2$$

Once these nitrogen compounds are formed, they must be captured to effectively remove them from the flue gas stream. This is especially important with NO_2 since a high enough concentration of NO_2 can cause a brown plume to form at the chimney exit and with HNO_3 (nitric acid) due to its corrosivity. For implementation at the Green Station, the process would depend on the wet lime scrubbers to capture the nitrogen compounds. These compounds would be captured as soluble calcium nitrite ($Ca(NO_2)_2$) and calcium nitrate ($Ca(NO_3)_2$) and would need to be immobilized by the Pozotec process used at Sebree for wastes disposal. To date, there has not been any published test results that show that nitrates and/or nitrites can be immobilized in a fixated flyash/scrubber sludge matrix.

and below were presented by FMC/URS to BREC as an example of the PerNOxide process applied to the units at R. D. Green. It was projected that a reagent molar ratio of 1.5:1 would be used and therefore, based on the economizer outlet temperature, would oxidize approximately 55% of the NO to NO_2 producing about 60 ppm of NO_2 exiting the air heater. Based on the estimates by URS/FMC of collection in the Green lime-based FGD system, there would be between 55% and 65% NO_2 removal in the scrubbers. It should be noted that URS stated that the NO_2 removal was a projection based on laboratory data and that pilot-scale testing would be needed to validate the laboratory results. Even if the removal projections were correct, this would result in an emission of about 25 ppm of NO_2. A paper by G. Blythe and C. Richardson of URS at the 2003 EPA/DOE/EPRI/AWMA Megasymposium stated "NO_2 has a brown color that can lead to flue gas plume coloration and increased opacity at concentrations as low as 10 ppm."

The experimental nature of the PerNOxide process, coupled with the potential for both a brown plume and a waste material with soluble nitrates and nitrites, does not recommend itself for implementation at the Green Units. Accordingly, S&L did not consider this process further in the technical evaluation.

Figure 4-1 — PerNOxide Oxidation of NO by Hydrogen Peroxide

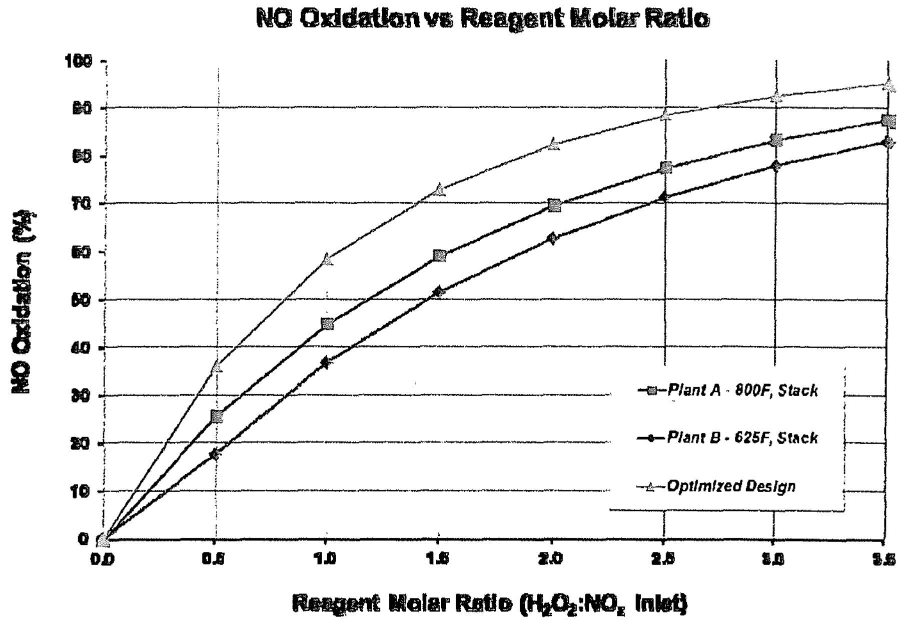
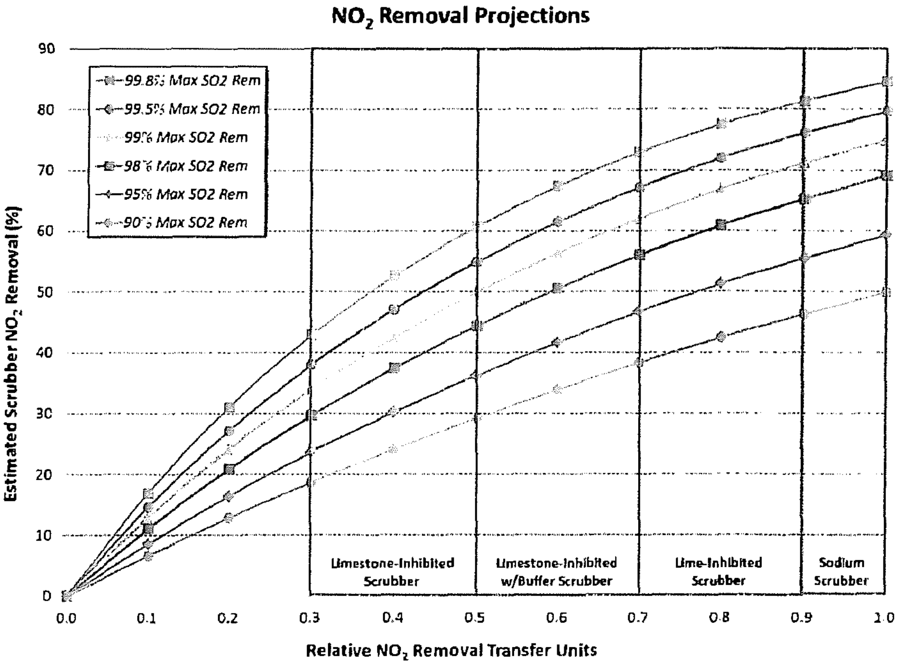


Figure 4-2 — Projected NO_2 Removal in FGD Systems Based On Laboratory Bench-Scale Results



4.3.4 Selective Non-Catalytic Reduction

The SNCR process does not require catalyst to drive the reaction; instead the driving force of the reaction is the high temperature within the boiler. NH_3 is injected into the hot flue gas at a location in the unit that provides optimum reaction temperature and residence time. The overall reactions of the SNCR process are as follows:

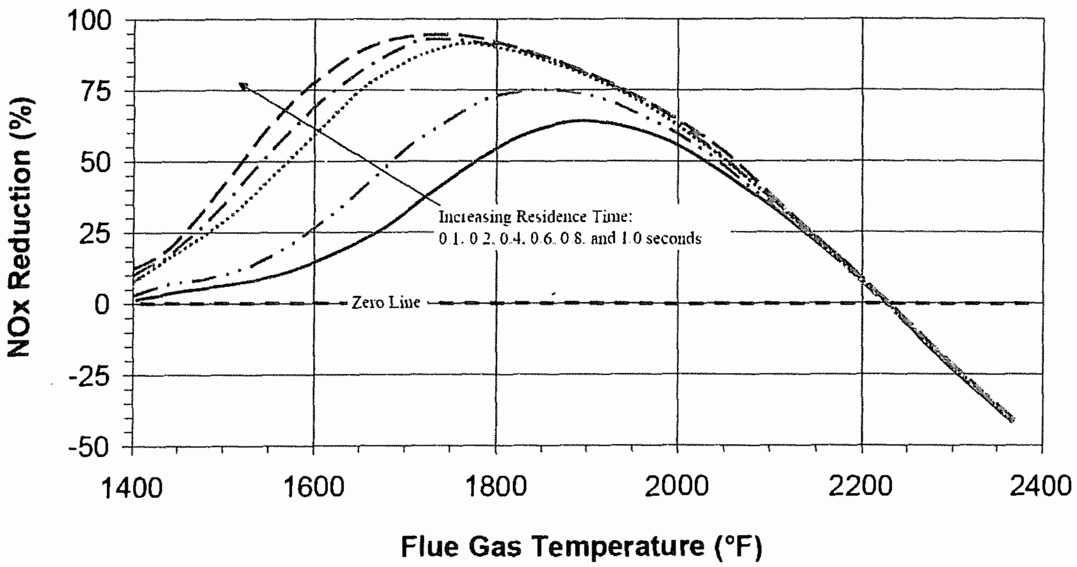
$NH_2CONH_2 + H_2O \longrightarrow 2NH_3 + CO_2$ (occurs between 1600°F and 2200°F)

$2NH_3 + 2NO + 0.5O_2 \longrightarrow 2N_2 + 3H_2O$

$2NH_3 + 2.5O_2 \longrightarrow 2NO + 3H_2O$ (occurs above 2000°F)

The preferred temperature range for this reaction is within 1600 and 2000°F, as shown in Figure 4-3. The best NO_X removal is achieved between 1700°F and 1850°F. At temperatures over 2000°F, NH_3 will oxidize and increase NO_X emissions. At temperatures below 1700°F, there will be more un-reacted NH_3, leading to higher ammonia slip.

Figure 4-3 — Theoretical NO_X Removal with SNCR Technology



Source: EPRI TR-102414, 1993 Report

Typically, NO_X removal efficiencies of 10-40% can be achieved with SNCR technology. While it is possible to achieve 40% NO_X reduction with SNCRs, 20% was chosen because factors such as ammonia slip, CO production, CO baseline values, and boiler temperatures all contribute to NO_X reduction capabilities. Without having boiler baseline test data, S&L conservatively estimates that SNCR can achieve 20% removal.

ROTAMIX® is a second generation SNCR technology provided by Nalco-Mobotec. It is a system that improves reagent mixing in the flue gas which in turn decreases the total chemical usage. The system also uses compressed air to increase penetration instead of water. The installation of ROTAMIX on Coleman Unit 1 instead of a traditional SNCR will incorporate significantly fewer modifications since the ROFA system is already in place. For Coleman units 2 and 3, that currently have conventional OFA systems, the addition of traditional SNCRs were assumed.

While SNCR systems are generally a lower capital cost option to reduce NO_X, the technology has certain disadvantages. For example, SNCR can result in increases in CO emissions. When water is injected in the boiler, it creates lower localized temperatures that inhibit the carbon in the coal from fully oxidizing to CO_2; instead a portion stays in the form of CO.

In addition, the effectiveness of SNCR is limited in regions with low oxygen, which is indicated by the presence of high amounts of CO in the boiler. If CO levels are above approximately 500ppm at the throat of the boiler, the NO_X removal can be severely limited. If boiler tuning does not bring CO levels down to an acceptable level, SNCR technology may not significantly reduce NO_X emissions. Testing would need to be conducted prior to selecting SNCR technology to ensure that SNCR would be effective at Coleman and Green stations.

Compared to SCR technology discussed in Section 4.3.5 below, SNCR systems have higher ammonia slip values. SCR is capable of achieving up to 90% NO_X removal with slip values of less than 2ppmvd NH_3 at 3% O_2, and that high of ammonia slip is only reached at the end of catalyst life. SNCR systems can achieve 5ppm slip, but to achieve higher NO_X removal it may be necessary to operate around 10ppm. SNCR slip can also vary more in load following units. Higher ammonia slip levels can lead to ammonium bisulfate (ABS) formation that can cause fouling of air heaters and precipitators. ABS pluggage can be a significant maintenance expense. In addition, higher ammonia slip values from SNCR can preclude ash sales for those units that market their ash.

The final concern with SNCR technology is its load-following capabilities. In general, SNCRs have a slow response to load shifts because the reactions are so dependent on temperature. As load increases or decreases, the optimum reaction temperature shifts up or down in the boiler. To minimize this effect, three levels of injection lances can be installed; although it is not always physically possible to do. This would allow greater opportunity to utilize the optimum temperature region by shifting which level is being used for injection.

4.3.5 Selective Catalytic Reduction

SCR technology allows for significantly higher reduction of NO_X in the flue gas than SNCRs due to the addition of the catalyst. However, the implementation of the system would include a much larger footprint, due to the additional space that the catalyst and duct work require. Coleman units are in the highest need of NO_X reduction in comparison with the rest of the fleet. Installation of SCRs at Coleman stations would significantly increase NO_X removal efficiencies (≈85%), however there does not appear to be enough room for the anticipated footprint of the technology.

Addition of SCR technology at the Green units also predicts NO_X reduction of approximately 85%. This would reduce emissions to below the anticipated 2014 allocation limits. Based on current operational data, installation of an SCR at either Green unit would result in reduced emission rates of approximately 1,800 tpy. This emission reduction would nearly cover the 1,932 tpy fleet-wide 2014 CSAPR allocation shortage.

Reid Unit 1 would also receive around 85% removal efficiency with the installation of an SCR system. However, based on current operational data, Reid 1 would still operate in a deficit compared to its 2014 allocations.

4.4 PARTICULATE MATTER CONTROL OPTIONS

4.4.1 Existing Electrostatic Precipitators and Wet Flue Gas Desulfurization Systems

All BREC units, except for Reid, are already equipped with ESPs and WFGD technologies. Unlike SO_2 and NO_X, which are under CSAPR regulation, particulate matter is under regulation by the MACT ruling. It is not possible to buy and sell emissions credits to stay in compliance with MACT. Therefore it is necessary for each site to be under 0.03 lb PM/MMBtu to comply with the anticipated allowance. Under the proposed regulations, either periodic stack testing or an installed PM continuous emission monitoring system (CEMS) will be needed to verify compliance.

Currently, Coleman Units 1, 2, and 3 are each equipped with an ESP and routed to a shared WFGD. Together the units emit approximately 0.0398 lb/MMBtu of PM and will need to reduce their total PM emissions by nearly 25% to comply with the anticipated MACT allowance. HMP&L units also are equipped with an ESP and WFGD system, yet still are not within compliance of the anticipated MACT limits. Current data suggests Unit 1 emits 0.0319 lb/MMBtu and Unit 2 emits 0.0324 lb/MMBtu of PM. Emissions would have to be reduced by approximately 6% to comply with their anticipated allowance.

The Wilson station is equipped with an ESP along with a Kellogg horizontal scrubber. With use of the current technologies, emissions are approximately 0.02 lb/MMBtu, which is within proposed MACT compliance limits. Each Green unit is also within compliance levels with emissions levels below 0.02 lb/MMBtu. These levels are achieved with the current ESP and WFGD systems in place.

4.4.2 Electrostatic Precipitator Upgrades

Recent stack and ESP test data suggests that the Coleman ESPs are currently achieving approximately 94% overall removal efficiency for particulates. Upgrading the current ESPs by installing advanced electrodes and high frequency transformer-rectifier (TR) sets will decrease particulate emissions to approximately 0.029 lb/MMBtu to keep within MACT compliance. HMP&L units are also equipped with ESPs that are currently achieving around 98% removal efficiency. By installing the same ESP upgrades as described for Coleman, data suggests PM emissions would be reduced to 0.029 lb/MMBtu for each unit.

Stack data was also collected for the Wilson unit that is currently operating an ESP. The data suggests that this unit is achieving approximately >99% removal efficiency for PM. Upgrades to the ESP will not further affect the removal efficiencies, since they are already achieving 99% removal. The same is true for the units at Green. However, potential ESP upgrades may be required if ACI and DSI systems are implemented upstream, due to the increased particulate loading.

4.4.3 Sorbent Injection

Condensable particulate matter (CPM) is also a major factor in PM compliance. These particulates are not removed by ESP or baghouse filter techniques. Since total PM is measured by adding CPM with filterable PM emissions, reduction of CPM is just as important as removing the filterable particulates. All BREC units except Wilson would benefit from the addition of a Hydrated Lime DSI system. Wilson currently has a DSI system installed and has demonstrated CPM emissions of 0.010 lb/MMBtu. CPM emissions are responsible for 45% of the total particulate emissions at the Coleman stations, 57% at Green Unit 1 and 73% at Unit 2, and nearly 45% at HMP&L Unit 1 and 63% at Unit 2. With the addition of a DSI system, CPM emissions can be expected to reduce approximately 50% at each of these units.

4.4.4 Baghouse

Baghouses for the BREC stations are not expected to be necessary for compliance with the total PM limits or mercury limits proposed in the EGU MACT rules. With the expectation that other lower cost technology combinations can achieve the proposed EGU MACT compliance; an estimated capital cost for installation of a baghouse at the Green station will be provided for informational purposes only. In the event that the final regulations were to mandate individual non-mercury HAP metals emissions for compliance, a more detailed study would need to be conducted.

4.4.5 Conclusions

The testing that BREC performed at the Coleman and HMP&L systems showed that the PM emissions were above the proposed MACT limits primarily due to condensable PM emissions.

The recommended use of dry sorbent (hydrated lime) injection will reduce the condensable PM emissions with only a slight increase in inlet dust loading to the ESP. The upgrade plans involve replacement of the discharge electrodes (DE) with newer advanced designs with more discharge points and also replacement of the existing T/R sets with high frequency T/R sets permitting more power to charge the fly ash in the ESP. Coupled with replacement of the conventional T/R sets will be some increased sectionalization of the existing precipitators for both power (less plate area be "served" by a single T/R set) and reliability reasons (loss of a T/R set has less of an effect on overall ESP performance). Similar upgrades have been completed by S&L on ESP's that are over 30 years old which are the same age range as the ESP's at HMP&L and Coleman.

In addition, S&L has recently participated in a number of activated carbon injection tests where PM was measured both baseline and during the tests. With activated carbon injection rates as high as 9 lb/million acf there was minimal increases in the outlet PM loading. Testing with hydrated lime has also shown minimal increases in particulate loading. Any lime that penetrates the ESP will pass through to the wet FGD systems at HMP&L and Coleman and will aid in SO2 removal.

The existing ESPs in conjunction with the WFGD systems and the previously described dry sorbent injection systems for SO_3 mitigation are expected to provide adequate control to meet the proposed EGU MACT total PM emission limits. If activated carbon injection systems are implemented for mercury emission reduction, then the ESP upgrades described above are expected to be required, subject to the results of existing ESP performance testing.

4.5 MERCURY CONTROL

4.5.1 Existing Electrostatic Precipitators and Wet Flue Gas Desulfurization Systems

ESP and other particulate reduction technologies are effective at reducing particulate mercury, while wet FGD systems typically only effectively capture ionic mercury. Without an inherently high level of halogens in the coal that is fired, there will still be high levels of mercury due to elemental mercury. The EGU MACT is expected to regulate mercury emissions to below 1.2 lb/TBtu.

All units at Coleman, Wilson, Green and HMP&L are equipped with both ESP and WFGD systems. However, HMP&L is the only station that has baseline mercury emissions that are below the anticipated MACT limit. HMP&L Unit 1 emits approximately 0.62 lb/TBtu and 0.47 lb/TBtu for Unit 2. The lower overall mercury level is due to the higher oxidation of elemental mercury to oxidized mercury that can be captured in the WFGD. The rest of the stations do not experience this increased oxidation and therefore are not within compliance with the anticipated limits. Current mercury emissions are 3.52 lb/TBtu combined at Coleman units, 1.77 at Wilson, and 3.09 and 2.58 at Green unit 1 and 2 respectively. Additional mercury control technologies are necessary for all BREC units, except the HMP&L units.

4.5.2 Activated Carbon Injection

Activated carbon injection (ACI) systems are capable of removing both elemental and oxidized mercury, reaching a total mercury reduction of 90%. All BREC units will benefit from the addition of an ACI system and will see reduction of mercury emissions from their current levels to the MACT requirement limit of 1.2 lb/TBtu. Since HMP&L is already witnessing compliance levels of mercury emissions, installation of an ACI system is not recommended due to the high cost of activated carbon compared to the unnecessary mercury removed.

4.5.3 Fuel Additives and Activated Carbon Injection

If there is not an inherently high level of halogens in the coal and brominated PAC is not used, addition of halogen additives to the coal can help oxidize elemental mercury. Since Coleman units are witnessing the highest levels of mercury, the units will benefit from addition of fuel additives in conjunction with an ACI system. The fuel additives will oxidize elemental mercury into a water soluble compound that can then be removed in the wet FGD, which will increase overall removal of mercury. Fuel additives should be able to oxidize greater than 90% of the mercury in the fuel.

4.5.4 Conclusions

If the existing air pollution control equipment is supplemented with the addition of an ACI system (except at HMP&L), the resulting system will be able to meet the proposed EGU MACT mercury limit of 1.2 lb/TBtu. Field testing can establish the capabilities of this technology. Since this reduction level is at the upper limit of what fuel additives and WFGD additives are expected to achieve, the cost summaries in this study are based on ACI, sorbent injection, and ESP upgrades.

4.6 AIR EMISSION TECHNOLOGY BENEFITS

4.6.1 CSAPR Technology Benefits

After reviewing the various potential options for establishing compliance with BREC's CSAPR allocations and eliminating outliers based on feasibility, existing plant configuration and potential cost savings benefits, the potential compliance technologies were reviewed against each other to determine emission reductions by unit. Estimated NO_X and SO_2 reductions, as compared to baseline emissions, are provided in Table 4-2 and Table 4-3 below.

Table 4-2 — SO_2 Emission Reductions by Technology

Plant / Unit	SO_2 Reduction from Baseline (tpy)			
	Return to Design Lime/Operation	Increase L/G for ~97% Removal	New Scrubber	Natural Gas Conversion
Coleman 1	858			
Coleman 2	937			
Coleman 3	835			
Wilson 1			8,389	
Green 1				1,870
Green 2				1,411
HMP&L 1		1,439		
HMP&L 2		1,910		
Reid 01				5,065

Returning the Coleman scrubber back to as-designed operation conditions and lime produces a reduction of approximately 2,630 tpy when compared to the baseline output. Increasing the liquid-to-gas ratio in the HMP&L

scrubbers to achieve ~97% removal provides a reduction of about 3,350 tpy. The current Wilson scrubber has undergone upgrades and uses additives to increase performance and is achieving an SO_2 removal efficiency of 91%. Because of the low operating efficiencies and high operating costs, Wilson has the greatest potential benefit with installing a new scrubber and will experience an approximate reduction in SO_2 emissions of 8,389 tpy. Converting the Reid 01 unit to natural gas is another choice for compliance with substantial emission reduction potential. Since Reid 01 currently has no technologies implemented for SO_2 control, a reduction of about 5,065 is to be expected.

Table 4-3 — NO_X Emission Reductions by Technology

Plant / Unit	NO_X Reduction from Baseline (tpy)			
	Advanced Burners	SNCR	SCR	Natural Gas Conversion
Coleman 1	186	372		
Coleman 2	159	317		
Coleman 3	204	409		
Wilson 1				
Green 1		410	1,742	815
Green 2		434	1,843	1,003
HMP&L 1				
HMP&L 2				
Reid 01				220

Several options were considered for reducing NO_X to achieve compliance with BREC's CSAPR allocations. Installation of an SCR at Green 1 and 2 will reduce NO_X emissions by 1,742 tpy and 1,843 tpy respectively. Retrofitting the Coleman units with SNCRs will reduce yearly NO_X emissions by nearly 1,100 tons. There is also potential for lower NO_X emissions by upgrading the existing low-NO_X burners at a number of plants. If the burners are upgraded for all the Coleman units, BREC should expect an overall reduction of approximately 549 tpy.

Each of the options given above is mutually exclusive except for natural gas conversion and will be selected from to achieve necessary reductions to meet forthcoming regulations. A complete fleet-wide CSAPR and

NAAQS compliance strategy using the technologies above will be developed in Section 5 of this report based on economic viability and estimated project schedules.

4.6.2 MACT Technology Benefits

Unlike SO_2 and NO_X emission reduction strategies for achieving CSAPR compliance, the potential options for MACT are more straightforward but also dependant on the technologies selected to meet CSAPR emissions. It's anticipated that ACI systems will be required at each unit except HMP&L 1 and 2 and that DSI systems will be required where ACI systems are installed to lower SO_3 emissions and improve Hg removal efficiency. Furthermore, due to increased particulate loadings from the ACI and DSI systems, it's anticipated that these units will also require ESP upgrades to achieve the MACT allowable limits. Since selection of these technologies is dependant on the implemented CSAPR technologies, a final recommendation of what is necessary for compliance will be determined after the cost benefits (NPV) of each CSAPR technology has been explored and compliance plan has been developed.

4.6.3 Summary

The compliance technologies discussed above have various pros and cons in their ability to meeting the anticipated CSAPR allocations. Although CSAPR allows significant flexibility in selecting technologies to implement because of credit sharing, MACT simply requires site-specific emissions limits. It is foreseen that all of the Units that continue to operate as coal-fired will need to install DSI systems to help mitigate formation of SO_3 as well as reduce overall PM emissions to levels compliant with MACT. ACI systems are also expected to be required on each of the coal-fired units except for HMP&L to reduce mercury emissions to MACT allowable rates. Capital, O&M, credit purchase and sales and fuel costs will be developed and discussed for a final compliance plan based on the economic evaluations in Section 5 of this report.

4.7 316(b) IMPINGEMENT MORTALITY AND ENTRAINMENT

4.7.1 Existing Intake Structure and Screen Technology

Based on the proposed 316(b) regulations and a review of all BREC units, this study considered new technology selections that may be able to meet an impingement reduction standard of 80% to 90%, or result in an intake velocity at the screen that is less than 0.5 feet per second for the Coleman and Sebree stations.

4.7.2 Compliance Technologies

Based on a review of the available technologies and data supporting the compliance viability of each technology, the following three were chosen to be considered for further evaluation and screening with regards to complying with these pending regulations for the Sebree and Coleman station:

Table 4-4 — Intake Structure 316(b) Compliance Technologies

Units	Technology	Target Compliance Level Based on Selected Technology (%)	Comments
Coleman & Sebree	Replacement Screens (WIP) with Fish Pumps / Return Systems	Impingement: 0.5 fps at screens or impingement mortality not to exceed 12% annual average, 31% monthly average. Entrainment: Demonstrate Best Technology Available (BTA)	Velocity through screens would not be reduced, but fish would be returned to the river to meet the reduction in impingement. 3/8" mesh could be used. Weekly testing would be required to confirm acceptable mortality rates.
	Cylindrical Wedgewire Screens		Velocity through screens would be reduced to 0.5 fps to meet the reduction in impingement. 3/8" mesh or 2-mm mesh could be used. However, once the entrainment piece of the regulation is finalized, retrofitting the screens would be difficult.
	Traveling Screen with Fish Return		Velocity through screens would not be reduced, but fish would be returned to the river to meet the reduction in impingement. Weekly testing would be required to confirm acceptable mortality rates.

The Coleman and Sebree stations will need of modifications to their existing intake structures to meet the proposed 316(b) regulations. In addition, it should also be noted that if Units were to alter their current operational practices or shut down, strategies could vary significantly. For instance, preliminary calculations show that if Reid were to discontinue operation, the circulating water pumps could be downsized for makeup to the HMP&L cooling towers, HMP&L sluice water make up, and to supply Henderson Water Utilities' South Water Treatment facility and overall intake velocity would be reduced to approximately 0.55 fps. Since this is relatively close to the anticipated regulatory limit of 0.5 fps, further analysis would need to be conducted if BREC would like to explore this means of compliance. Technology selection of the three proposed options for compliance will be chosen based lowest lifetime cost accounting for associated capital and O&M costs. Details of this analysis covered in Section 5 of this report.

4.8 COAL COMBUSTION RESIDUALS

4.8.1 Existing Operation and Technology

Either Subtitle C or Subtitle D will result in an increase in O&M disposal costs for BREC due to groundwater monitoring requirements that will be imposed on the existing landfill that receives these wastes. Several of the BREC facilities will need to implement upgrades to their exist waste/ash handling systems. If Subtitle D is chosen, Wilson would not require any modifications but would still potentially incur additional disposal fees. All other stations would require significant modifications to convert the existing sluiced systems. If Subtitle C is chose, each station would still need to perform the modifications necessary for Subtitle D compliance and would also need to convert the existing pressurized pneumatic transport systems to vacuum systems.

4.8.2 Conclusions and Recommendations

This study will consider a conversion of the existing bottom ash handling systems to one of the dry technologies discussed in Section 3.2.7. The recommended technology (dewatering bin system or remote submerged scraper conveyor) will be selected based on net present value (NPV) analysis based on estimated capital and O&M costs. Future ash disposal will then be conducted by hauling the bottom ash waste to landfill, along with the fly ash and WFGD waste product. Upper bound estimates for the transportation costs for CCR waste products under Subtitle C (hazardous waste) and Subtitle D (non-hazardous waste) are provided. It is assumed for the purpose of this study that the moisture content of the dewatered bottom ash that currently exists before truck loading is approximately the same as that which occurs with a dewatering bin system or submerged scraper conveyor. In order to close the existing ponds, BREC would have to take the following four steps:

1. Eliminate free liquids or solidify the remaining waste and residue
2. Stabilize the remaining wastes sufficiently to support final cover
3. Construct the final cover
4. Provide maintenance and monitoring for a 30-year period.

An additional step involving the redirection of miscellaneous waste streams that currently flow into the ash ponds, including boiler blowdown, limestone pile runoff, WFGD blowdown, etc. may also be necessary. It is estimated that if such regulations were to be implemented, wastewater stream treatment facilities would be costly. A detailed water balance study should be performed once the EPA's wastewater effluent guidelines are published to better assess the necessary process changes and impacts of this redirection, as well as assess possible beneficial reuse of the redirected waste streams.

Last page of Section 4.

5. CAPITAL AND O&M COST DEVELOPMENT FOR PHASE III SELECTIONS

5.1 TECHNOLOGY COSTS

5.1.1 Capital Costs

The estimated capital costs provided are based on a total installed cost that includes the following:

- Equipment and materials
- Direct field labor
- Indirect field costs and engineering
- Contingency
- Initial inventory and spare parts
- Startup and commissioning

The capital costs do not include; sales taxes, property taxes, license fees and royalties, owner costs, or AFUDC (Allowance for Funds Used During Construction). The costs are based on a minimal-contracts lump-sum project approach. The total installed costs are factored from recent projects and quotes obtained by S&L. No specific quotes or engineering was completed for any of the projected upgrades for the BREC units. The costs provided herein reflect an approximate accuracy of +/-20% and are not indicative of costs that may be negotiated in the current marketplace. These costs should not be used for detailed budgeting or solicitation of pollution control bonds.

5.1.2 Operation and Maintenance Costs

The O&M costs are a combination of variable and fixed costs. The O&M costs are reported in fourth quarter 2011 dollars.

The variable O&M costs include applicable items such as the following:

- Reagent and Disposal
- Auxiliary Power

- Makeup Water
- Bag replacement

The fixed O&M costs include the following:

- Operating Labor
- Maintenance Labor
- Maintenance Materials

5.1.3 Air Pollutant Control Capital Cost Summary

Table 5-1 shows estimated capital and O&M costs for all of the screened technologies considered in this evaluation. O&M costs are shown as the additional cost to current budgets and expenses.

Table 5-1 — Estimated Costs for Technologies Considered (Air Pollution Compliance)
(Additional Costs to the Current Budgets and Expenses)

Pollutant	Station / Unit	Technology	Capital Cost (2011$ Millions)	O&M Cost (2011$ Millions)	Comments
SO_2 Control	Wilson	New WFGD Absorber Vessel	139.0	0.69	Replacement of the existing horizontal scrubber with a new state-of-the-art vertical scrubber. Existing limestone preparation and dewatering systems would be reused to support new vessel. (Capital cost estimate was based on SESS budget proposal number 4296 provided 11/11/11)
	Green 1/2	Natural Gas Conversion	25.6 – 27.6 (per unit)	47.2(1) (per unit)	The available gas supply line near green currently has capacity for conversion of one (1) of the green units. If both are converted, the higher capital value would need to be applied to both for a new supply line. The conversion cost includes installation of new burners, a flue gas recirculation system and a natural gas supply system.
	HPM&L 1/2	Existing WFGD with Increased L/G Upgrades	3.15 (per unit)	0.38 (per unit)	Based on received data the current HMP&L scrubbers are capable of increasing removal efficiency by operating a second recirculation pump. The capital cost for this modification includes installation of a third recycle pump to maintain system redundancy and tipping of the existing ID fans with installation of new motors to account for additional system pressure losses as a result of increased removal spray flow.

Pollutant	Station / Unit	Technology	Capital Cost (2011$ Millions)	O&M Cost (2011$ Millions)	Comments
	Reid 1	Natural Gas Conversion	1.2	3.84[1] (Fuel Cost: 5.61, Other: -1.77)	Reid already has natural gas supply and burners in place. Based on discussions with BREC these have not been placed into service. The capital allowance is an approximation of maintenance, testing and other incurred fees to startup the existing system.
NO_x Control	Coleman 1/2/3	SNCR (Unit 1)	2.4	1.56	Unit 1 currently has the ROFA system installed for NO_x control. Installation of a SNCR system would provide the desired removal efficiencies at a reduced cost over conventional SNCR technologies.
		SNCR (Unit 2 & 3)	2.7 (per unit)	1.58 (per unit)	Cost is based on a complete system with necessary piping, valves, heating units, reagent preparation equipment, etc.
		Advanced (third Generation) Low-NO_x Burners	5.94 (per unit)	0	Upgrade includes replacement of existing first generation Low-NO_x burners with new advanced burners.
	Wilson	Advanced (third Generation) Low-NO_x Burners	8.61	0	Upgrade includes replacement of existing first generation Low-NO_x burners with new advanced burners.
	Green 1/2	SNCR	3.5 (per unit)	1.61 (per unit)	Cost is based on a complete system with necessary piping, valves, heating units, reagent preparation equipment, etc.
		SCR	81 (per unit)	1.47 (per unit)	Capital cost for installation of an SCR at Green includes foundations, duct modifications, steel structures, SCR catalyst and new ID fans for the increased pressure loss.
		SCR Catalyst	2.43	0	The catalyst cost for replacement of all three (3) layers (not including labor). It's anticipated that a single layer would have to be replaced every two (2) years and the remaining layers would be rotated. A new set of catalyst would be required every six (6) years. $0.41M is the annualized cost for the 6-year cycle life of the catalyst.
		Natural Gas Conversion	See SO_2 Above	See SO_2 Above	Conversion to natural gas will provide a reduction in NO_x emissions in addition to the SO_2 reductions. See SO_2 section above for details of installation.
		Advanced (third Generation) Low-NO_x Burners + OFA	8.64	0	Upgrade includes replacement of existing first generation Low-NO_x burners with new advanced burners and over fire air.
	Reid 1	Natural Gas Conversion	See SO_2 Above	See SO_2 Above	Conversion to natural gas will provide a substation reduction in NO_x emissions in addition to the SO_2 reductions. See SO_2 section above for details of installation.

Pollutant	Station / Unit	Technology	Capital Cost (2011$ Millions)	O&M Cost (2011$ Millions)	Comments
HCl	All Units	HCl Monitor	0.24 (per stack)	0.02 (per stack)	Typical cost for installation of an HCl monitor is shown. Installation is not usually dependant on unit size or other operational parameters. Required for units not able to use SO_2 emissions for MACT compliance.
Hg	Coleman 1/2/3	Activated Carbon Injection System	4.0 (per unit)	0.81 (per unit)	Complete carbon injection systems are included in the estimated capital costs provided. System includes foundations, silo, transport piping, injection lances, blowers and all other necessary components of a complete activated carbon injection system.
	Wilson		4.5	2.19	
	Green 1/2		4 (per unit)	1.14 (per unit)	
Condensable Particulates	Coleman 1/2/3	Hydrated Lime DSI	5.0 (per unit)	0.27 (per unit)	Complete dry sorbent injection systems are included in the estimated capital costs provided. System includes foundation, silo, transport piping, injection lances, blowers and all other necessary components of a complete hydrated lime injection system.
	Green 1/2		5.0 (per unit)	0.32 (per unit)	
	Wilson	Hydrated Lime DSI + Low Oxidation Catalyst	6.5	0.50	Complete dry sorbent injection systems as well as upgrading the existing catalyst are included in total cost estimate. The costs are on a per unit basis and include complete unitized systems with all necessary components (silo, blowers, piping, lances, etc.)
	HMP&L 1/2		6.0 (per unit)	0.29 (per unit)	
Filterable Particulates	Coleman 1/2/3	Upgrade Existing with Advanced Electrodes and High Frequency TR Sets	2.4 (per unit)	0.06 (per unit)	Implementation of advanced electrode technology and the addition of high frequency transformer rectifier sets may be needed for each of the units listed. Choice of modification of the existing ESP at each unit will be decided based on the particular unit's present performance capability and the chosen technologies for mitigating other regulated pollutants.
	Wilson		4.3	0.15	
	Green 1/2		3.1 (per unit)	0.05 (per unit)	
	HMP&L		2.5 (per unit)	0.08 (per unit)	
Total Particulates	Coleman 1/2/3	Particulate Matter Monitor	0.24 (per stack)	0.02 (per stack)	Particulate monitors will be needed at the listed sites to demonstrate compliance with the anticipated MACT regulations. Typical cost for installation of an PM monitor is shown. Installation is not usually dependant on unit size or other operational parameters.
	Wilson				
	Green 1/2				

(1) Natural gas O&M cost includes fuel cost and were developed based on baseline heat inputs and the economic parameters show in Table 1-1. O&M savings that are associated with day-to-day operation and outage work from conversion to natural gas have been estimated based on information provided by BREC and S&L's experience.

Conversion of an existing coal-fired unit to natural gas increases fuel costs. However, expected maintenance and day-to-day operational costs are expected to decline after converting an existing coal unit to natural gas. The fixed O&M for a typical coal unit is about $25 per kilowatt per year, based on several variables, e.g., number of units, age of units, degree of unionization, management practices, and other factors. S&L estimates that about one third of that cost would be eliminated for a coal plant converted to operation on natural gas. The cost reduction would include elimination of the ash handling and coal handling, WFGD reagent savings and a reduction in water treatment and other expenses. The total savings are estimated to be approximately $9/kW/year in fixed O&M cost. Current BREC O&M costs have been adjusted accordingly and are reflected in the costs shown above.

5.1.4 Options Not Considered for Air Compliance

Although it is not anticipated, initial testing may require that an EGU meet non-Hg HAP metal emission limits in addition to TPM. The highest probability of achieving compliance with possible non-Hg HAP emission limits is with a baghouse. Provided below is an order of magnitude capital cost estimate for installation of a baghouse at BREC's Green and HMP&L stations. This estimate is provided for information only and a more detailed cost estimate would need to be conducted to confirm overall project capital and O&M costs.

Table 5-2 — Baghouse Capital Cost Estimates

Station / Unit	Capital Cost (2011$ Millions)
Green / 1&2	75 (per unit)
HMP&L / 1&2	51 (per unit)

5.1.5 Non-Air Pollutant Technology Cost Summary

Table 5-3 shows capital and O&M costs for compliance with 316(b) regulations and coal combustion residual handling (CCR) regulations, for all of the screened technologies considered in this evaluation. For future CCR transport and disposal under Subtitle C (hazardous waste classification for all fly ash, bottom ash, and WFGD waste product), transportation and disposal costs could be in excess of $80/ton, it is not expected that the Subtitle C regulations will be promulgated. As such, future CCR transport and disposal costs are estimated based on Subtitle D (non-hazardous waste classification) being promulgated.

Table 5-3 — Estimated Technology Costs (316(b) and CCR Compliance (Additional Costs to the Current Budgets and Expenses)

Regulation	Station / Unit	Technology	Capital Cost (2011$ Millions)	O&M Cost (2011$ Millions)	Comments
316(b) IM&E	Coleman 1/2/3	Replacement Screens (WIP) with Fish Pumps / Return System	1.33 (per unit)	0.25 (per unit)	Cost is on a per unit basis for the six intake bays (two per unit). Estimated mortality testing costs have been included in the provided O&M.
		Traveling Screens with Fish Return	1.87 (per unit)	0.25 (per unit)	Cost is on a per unit basis for the six intake bays (two per unit). Estimated mortality testing costs have been included in the provided O&M.
		Cylindrical Wedgewire Screens	2.15 (per unit)	0.27 (per unit)	Wedgewire technology will reduce through-screen velocity to or below the proposed 0.5 fps. Compliance will not require weekly mortality testing. O&M cost includes use of a purge-air system to prevent debris from gathering on the screens.
	Sebree	Replacement Screens (WIP) with Fish Pumps / Return System	2.05	0.37	Cost is on a per unit basis for the three intake structures. Estimated mortality testing costs have been included in the provided O&M.
		Traveling Screens with Fish Return	2.80	0.37	Cost is on a per unit basis for the three intake structures. Estimated mortality testing costs have been included in the provided O&M.
		Cylindrical Wedgewire Screens	2.45	0.38	Wedgewire technology will reduce through-screen velocity to or below the proposed 0.5 fps. Compliance will not require weekly mortality testing. O&M cost includes use of a purge-air system to prevent debris from gathering on the screens.
CCR (Conversion to Dry Bottom Ash)	Coleman 1/2/3	Submerged Scraper Conveyor (Remote)	28.0	1.25	Currently bottom ash is sluiced to a pond on site. Cost is to provide two 100% remote SSCs to be shared between the three units.
		Dewatering Bin System	38.0	0.86	Bottom ash will be routed to three new dewatering bins before it is collected and taken offsite to a landfill.
	HPM&L 1/2	Submerged Scraper Conveyor (Remote)	28.0	0.97	Currently bottom ash is sluiced to a pond on site. Cost is to provide two 100% remote SSCs to be shared between the two units.
		Dewatering Bin System	38.0	0.68	Bottom ash will be routed to three new dewatering bins before it is collected and taken offsite to a landfill.

	Green 1/2	Submerged Scraper Conveyor (Remote)	28.0	1.25	Currently bottom ash is sluiced to a pond on site. Cost is to provide two 100% remote SSCs to be shared between the two units.
		Dewatering Bin System	38.0	0.87	Bottom ash will be routed to three new dewatering bins before it is collected and taken offsite to a landfill.
Pressurized Pneumatic Transport System Conversion (Subtitle C or D for Coleman, Subtitle C only for HMP&L, Green and Wilson)	Coleman 1/2/3	Convert Pressurized Fly Ash System to Vacuum	10.0	0	Currently Coleman fly ash is sluiced to an onsite waste ash pond. Conversion of existing system to vacuum pneumatic system.
	HPM&L 1/2	Convert Pressurized Fly Ash System to Vacuum	6.0	0	HMP&L currently has a vacuum pneumatic system to storage silo then pressurized system to Green storage silo. Conversion of pressurized portion of system to vacuum.
	Green 1/2	Convert Pressurized Fly Ash System to Vacuum	6.0	0	Green currently has a pressurized pneumatic system to storage silo. Conversion of pressurized system to vacuum.
	Wilson	Convert Pressurized Fly Ash System to Vacuum	5.0	0	Wilson currently has as pressurized fly ash transport system that takes ash to an onsite silo and is used for stabilizing scrubber waste. Conversion of pressurized pneumatic transport system to vacuum.

5.2 NET PRESENT VALUE COST COMPARISON

Based on the factors detailed in Section 1.2 and costs from Section 5.1, a net present value (NPV) analysis was conducted to compare the screened technologies on the same lifetime cost basis. The O&M portion of the analysis included escalation from the time the technology options are commissioned in 2014 through the end of the operating life of each system and accounts for the benefits associated with assumed credit costs. The net present value for the capital charges and O&M costs, over the operating life, are discounted back to the commercial operating date of 2014.

5.2.1 Lifetime Cost of Individual CSAPR Control Technologies

Based on the economic parameters of Table 1-1, an install date of 2014, developed capital and O&M cost estimates and the predicted performance of implementing each CSAPR related technology, the relative payback point was determined for all applicable screened technologies. Table 5-4 and

Table 5-5 below show the relative value of each modification by determining a "break even" point at which the NPV of a given modification is equivalent to $0 and thus establishing an economically hierarchy for developing a implementation and scheduling strategy.

Table 5-4 — SO_2 Break Even Credit Cost by Technology

Station / Unit	Compliance Technology	SO_2 Credit Reduction (Tons Per Year)	"Break Even" SO_2 Credit Cost	NPV at Baseline Credit Cost (2011$ Million)
HMP&L 1&2	Run Two Recycle Pumps (Increase L/G)	3,349	$382	($4.13)
Reid 01	Natural Gas Conversion(1)	5,065	$669	$8.91
Wilson	New WFGD Absorber	8,389	$1,445	$82.55
Green 1&2	Natural Gas Conversion(1)	3,281	$28,593	$989.58
Green 2	Natural Gas Conversion(1)	1,411	$32,775	$474.01

(1) Conversion to natural gas also reduces NO_X emissions and excludes the unit from any potential MACT compliance issues. Conversion inherently makes the unit susceptible to changes in natural gas pricing but eliminates dependency on coal and other reagent markets.

Based on the results of the NPV analysis shown above, it is most cost effective for BREC to upgrade the existing HMP&L scrubbers, convert Reid 01 to natural gas and then build a new WFGD at Wilson. SO_2 emission reductions resulting from implementation of these three lowest break-even cost technologies/upgrades will allow BREC to meet their CSAPR 2014 SO_2 allocations.

Table 5-5 — NO_X Break-Even Credit Cost by Technology

Station / Unit	Compliance Technology	NO_X Credit Reduction (Tons Per Year)	"Break Even" NO_X Credit Cost	NPV at Baseline Credit Cost (2011$ Million)
Coleman 1/2/3	Advanced Low- NO_X Burners	549	$2,670	$1.0
Green 1&2	SNCR	844	$4,500	$17.6
Coleman 1	SNCR	372	$4,729	$8.6
Green 2	SCR	1,843	$4,788	$43.9
Coleman 2&3	SNCR	726	$4,965	$18.6
Green 1	SCR	1,742	$5,064	$46.5
Reid 01	Natural Gas Conversion(1)	220	$6,392	$8.9
Green 2	Natural Gas Conversion(1)	1,003	$47,905	$474.0
Green 1&2	Natural Gas Conversion(1)	1,818	$53,214	$989.6

(1) Conversion to natural gas also reduces SO_2 emissions and excludes the unit from any potential MACT compliance issues. Conversion inherently makes the unit susceptible to changes in natural gas pricing but eliminates dependency on coal and other reagent markets.

The NPV analysis shown above indicates that it is most cost effective to upgrade the existing upgrade the Coleman Low-NO_X burners install SNCR systems at Green and/or Coleman and install an SCR at Green. NO_X emission reductions resulting from implementation of these lowest break-even cost technologies/upgrades will allow BREC to meet their CSAPR 2014 SO_2 allocations.

Table 5-6 shows two possible strategies for complying with CSAPR in 2014. Fleet-wide NO_X compliance for 2014 can be achieved by installing a total of three SNCR systems or a single SCR system at Green Unit 2. Comparing the NPV values for these two strategies favors SNCR technology.

Table 5-6 — CSAPR 2014 NO_X Compliance Strategies

	Strategy 1 SNCR at Coleman 1 & Green 1/2 and Reid 1 Natural Gas Conversion	**Strategy 2** SCR at Green 2 and Reid 1 Natural Gas Conversion
Total NO_X Reduction (tpy)	1,436	2,063
Net Present Value (2011$ Millions)	$35.1	$52.8

However, Table 5-7 shows two possible strategies for complying with potential revisions to CSAPR in the 2016 or 2018 timeframe as a result of potential NAAQS revisions as described in section 2.1.4. To meet the estimated requirements to comply with Phase II of CSAPR, a total of four SNCR systems plus an SCR at Green 2 would be required, or two SCR systems could be installed at Green. Comparing the NPV values for these longer-term compliance strategies are nearly equal. This is because while the SCR system is significantly higher in capital cost, only the stoichiometric amount of urea is injected to achieve high NOX removal, and it therefore has lower O&M costs compared to four SNCR systems. In contrast, SNCRs have lower capital cost but significantly higher operating costs due to the amount of urea consumed to achieve lower NOX removal efficiencies.

Table 5-7 — NAAQS 2016/18 NO_X Compliance Strategies

	Strategy 1 SNCR at Coleman 1/2/3 & Green 1, SCR at Green 2 and Reid 1 Natural Gas Conversion	**Strategy 2** SCR at Green 1 & 2 and Reid 1 Natural Gas Conversion
Total NO_X Reduction (tpy)	3,517	3,805
Net Present Value (2011$ Millions)	$88.8	$90.4

While the immediate compliance targets can be met with three SNCR systems at a lower NPV, S&L recommends implementing SCR technology at the Green units as part of a lower risk, longer-term compliance strategy. As discussed in section 4.3.4, SNCR performance capabilities may be limited by higher levels of CO in the boiler. In addition, operation of the SNCR system can increase CO emissions. The higher ammonia slip values that result from SNCR compared to SCR may cause increased fouling of downstream equipment and add to maintenance costs. SNCR systems are also slow to respond to load changes, which can cause problems on load-following units. The Green units use coal-reburn, and there is no known SNCR experience in conjunction with coal-reburn. Given that the impacts of these items have not been tested at Coleman or Green, and given that increasingly stringent regulations may eventually require at least 1 SCR at Green Station, implementing SCR systems at both units is an overall lower risk strategy. Furthermore, it is likely that many, if not all, of the design elements for the two SCR systems would be identical. This could potentially lead to lower overall capital costs for the second SCR and would simplify operations and maintenance requirements since the entire compliance strategy would be implemented at a single station.

It is also important to note that although converting Reid 01 to natural gas has a larger "break even" point than burner upgrades, SNCR or SCR options, the benefits go beyond those noticed in a NOX credit cost sensitivity analysis and must be considered further. Natural gas conversions for the Green units appear to be beyond what is economically justifiable at present time.

Justification for conversion of an existing BREC unit to natural gas is highly dependent on future fuel cost assumptions. As such, a sensitivity analysis was conducted on natural gas fuel price while holding SO_2 and NO_X credit prices constant at their baseline value. NPV for the Reid 1 gas conversion will reach equilibrium when natural gas prices are $4.12/MMBtu whereas Green 1 and 2 natural gas conversion will require a natural gas price of $2.23/MMBtu. Given that the fluctuations in the natural gas market are highly unpredictable over the twenty year lifetime of the project, consideration should be given to the uncertainty associated with such a strategy.

Table 5-8 — Natural Gas Pricing Sensitivity

Modification	"Break Even" Gas Pricing at Baseline NO_X & SO_2 Credit Cost (2011$)
Reid 1 Conversion	$4.12
Green 1 & 2 Conversion	$2.23

5.2.2 Fleet-Wide Air Pollutant Compliance Strategy (2014 CSAPR)

Based on examination of the relative value added of each technology, an overall air pollutant compliance strategy was developed. This strategy includes the minimal technologies required to meet both the CSAPR and

MACT emission limits. The technologies selected as well as the emission surpluses and deficits are shown in Table 5-9 below.

Table 5-9 — Air Pollutant Compliance Strategy (2014 CSAPR)

BREC Unit	Technology Selection						Emission Surplus / (Deficit) vs. Allocation			
	CSAPR - Selection		MACT - Selection				CSAPR II - 2014 (Tons)		Projected NAAQS (Tons)	
	SO_2	NO_X	HCl	Hg	CPM	FPM	SO_2	NO_X	SO_2	NO_X
Coleman Unit C01	None**	Advanced Burners	HCl level is below anticipated MACT limits Installation of an HCl monitor is needed since SO2 can not be used as a surrogate.***	Activated Carbon Injection	Hydrated Lime - DSI	Advanced Electrodes & High Frequency TR Sets	(323)	(831)	(553)	(1000)
Coleman Unit C02	None**	Advanced Burners	HCl level is below anticipated MACT limits Installation of an HCl monitor is needed since SO2 can not be used as a surrogate.***	Activated Carbon Injection	Hydrated Lime - DSI	Advanced Electrodes & High Frequency TR Sets	(323)	(585)	(553)	(753)
Coleman Unit C03	None**	Advanced Burners	HCl level is below anticipated MACT limits Installation of an HCl monitor is needed since SO2 can not be used as a surrogate.***	Activated Carbon Injection	Hydrated Lime - DSI	Advanced Electrodes & High Frequency TR Sets	(345)	(942)	(590)	(1121)
Wilson Unit W01	New Tower Scrubber - 99% removal	None	Higher L/G or new tower for increased SO2 removal to below 0.2 lb/mmBtu will permit reporting SO2 data as prima facia evidence of compliance with HCl emission limits	Activated Carbon Injection & New SCR Catalyst	Low Oxidation SCR catalyst + Hydrated Lime - DSI Control NH3 slip from SCR	Advanced Electrodes & High Frequency TR Sets	2565	1711	1843	1182
Green Unit G01	None	None	HCl Montior is not required since SO2 is below 0.2 lb/mmBtu	Activated Carbon Injection	Hydrated Lime - DSI	Potential ESP Upgrades Due to ACI and DSI	91	(613)	(302)	(900)
Green Unit G02	None	SCR @ 85% Removal	HCl Montior is not required since SO2 is below 0.2 lb/mmBtu	Activated Carbon Injection	Hydrated Lime - DSI	Potential ESP Upgrades Due to ACI and DSI	357	1128	3	837
HMP&L Unit H01	Run both pumps & spray levels, install 3rd pump as spare	None	Higher L/G for increased SO2 removal to below 0.2 lb/mmBtu will permit reporting SO2 data as prima facia evidence of compliance with HCl emission limits	None needed due to oxidation across SCR and WFGD	Low Oxidation SCR catalyst + Hydrated Lime - DSI Control NH3 slip from SCR	ESP Maintenance / Possible Upgrade	463	456	213	273
HMP&L Unit H02	Run both pumps & spray levels, install 3rd pump as spare	None	Higher L/G for increased SO2 removal to below 0.2 lb/mmBtu will permit reporting SO2 data as prima facia evidence of compliance with HCl emission limits	None needed due to oxidation across SCR and WFGD	Low Oxidation SCR catalyst + Hydrated Lime - DSI Control NH3 slip from SCR	ESP Maintenance / Possible Upgrade	454	526	196	337
Reid Unit R01*	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	218	(132)	174	(164)
Reid Unit RT	None	None	None	None	None	None	4	(39)	2	(40)
TOTAL							3161	680	432	(1349)

**Note SO2 emissions in this scenario have been adjusted to reflect recent data received from BREC confirming that the Coleman FGD is capable of producing emission rates of 0.25lb/MMBtu and reaching removal rates of approximately 95%

***Note four (4) HCl monitors are required for Coleman One (1) for the common WFGD stack and one (1) for each unit bypass stack

The complete compliance strategy above takes several of the individual technologies and implements them based on value added and 2014 CSAPR compliance. Although break-even costs for installation of an SNCR is near that of an SCR, installation of an SCR has increased reliability and operational flexibility compared to an SNCR. The strategy has also accounted for necessary upgrades to achieve MACT compliance given the proposed CSAPR modifications are put in place. Because this compliance strategy is near BREC's exact NO_X CSAPR allocation limit, it is minimally affected by credit market price fluctuations.

A sensitivity analysis was also conducted on the CSAPR technologies as a whole. Holding NO_X credit prices constant, the "break even" credit cost for SO_2 was found to be approximately \$1,000. Holding SO_2 credit prices constant, the "break even" credit cost for NO_X was found to be approximately \$4,440. The suggested CSAPR compliance strategy is more sensitive to the price of NO_X credits as a result of the large lifetime costs associated with upgrading NO_X control technologies and that the current NO_X emission surplus is 16% over as apposed to SO_2 being 50% over their 2014 allocations. However, BREC should consider implementing a strategy of technologies such as that shown in Table 5-9 to meet the upcoming CSAPR regulatory limits in order to avoid the uncertainties that come with prediction of future market credit costs.

5.2.3 Fleet-Wide Air Pollutant Compliance Strategy (Potential 2016 NAAQS)

Although it is unclear what, if any, reductions will be necessary with any forthcoming regulations, an additional compliance strategy was developed to demonstrate necessary modifications required to meet a 20% reduction beyond the 2014 CSAPR as part of NAAQS in 2016.

Table 5-10 — Air Pollutant Compliance Strategy (2016 NAAQS)

BREC Unit	Technology Selection									
	CSAPR - Selection		MACT - Selection				CSAPR II - 2014 (Tons)		Projected NAAQS (Tons)	
	SO_2	NO_X	HCl	Hg	CPM	FPM	SO_2	NO_X	SO_2	NO_X
Coleman Unit C01	None**	Advanced Burners	HCl level is below anticipated MACT limits Installation of an HCl monitor is needed since SO2 can not be used as a surrogate.***	Fuel Additive & Activated Carbon Injection or Activated Carbon Injection	Hydrated Lime - DSI Control NH3 slip from ROTOMIX	Advanced Electrodes & High Frequency TR Sets	(323)	(831)	(553)	(1000)
Coleman Unit C02	None**	Advanced Burners	HCl level is below anticipated MACT limits Installation of an HCl monitor is needed since SO2 can not be used as a surrogate.***	Fuel Additive & Activated Carbon Injection or Activated Carbon Injection	Hydrated Lime - DSI Control NH3 slip from SNCR	Advanced Electrodes & High Frequency TR Sets	(323)	(585)	(553)	(753)
Coleman Unit C03	None**	Advanced Burners	HCl level is below anticipated MACT limits Installation of an HCl monitor is needed since SO2 can not be used as a surrogate.***	Fuel Additive & Activated Carbon Injection or Activated Carbon Injection	Hydrated Lime - DSI Control NH3 slip from SNCR	Advanced Electrodes & High Frequency TR Sets	(345)	(942)	(590)	(1121)
Wilson Unit W01	New Tower Scrubber - 99% removal	None	Higher L/G or new tower for increased SO2 removal to below 0 2 lb/mmBtu will permit reporting SO2 data as prima facia evidence of compliance with HCl emission limits	Activated Carbon Injection & New SCR Catalyst	Low Oxidation SCR catalyst + Hydrated Lime - DSI Control NH3 slip from SCR	Advanced Electrodes & High Frequency TR Sets	2565	1711	1843	1182
Green Unit G01	None	SCR @ 85% Removal	HCl Montior is not required since SO2 is below 0.2 lb/mmBtu	Activated Carbon Injection	Hydrated Lime - DSI	Potential ESP Upgrades Due to ACI and DSI	91	1130	(302)	842
Green Unit G02*	None	SCR @ 85% Removal	HCl Montior is not required since SO2 is below 0.2 lb/mmBtu	Activated Carbon Injection	Hydrated Lime - DSI	Potential ESP Upgrades Due to ACI and DSI	357	1128	3	837
HMP&L Unit H01	Run both pumps & spray levels, install 3rd pump as spare	None	Higher L/G for increased SO2 removal to below 0 2 lb/mmBtu will permit reporting SO2 data as prima facia evidence of compliance with HCl emission limits	None needed due to oxidation across SCR and WFGD	Low Oxidation SCR catalyst + Hydrated Lime - DSI Control NH3 slip from SCR	ESP Maintenance / Possible Upgrade	463	456	213	273
HMP&L Unit H02	Run both pumps & spray levels, install 3rd pump as spare	None	Higher L/G for increased SO2 removal to below 0 2 lb/mmBtu will permit reporting SO2 data as prima facia evidence of compliance with HCl emission limits	None needed due to oxidation across SCR and WFGD	Low Oxidation SCR catalyst + Hydrated Lime - DSI Control NH3 slip from SCR	ESP Maintenance / Possible Upgrade	454	526	196	337
Reid Unit R01*	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	218	(132)	174	(164)
Reid Unit RT	None	None	None	None	None	None	4	(39)	2	(40)
TOTAL							3161	2422	432	394

**Note SO2 emissions in this scenario have been adjusted to reflect recent data received from BREC confirming that the Coleman FGD is capable of producing emission rates of 0.25lb/MMBtu and reaching removal rates of approximately 95%

***Note four (4) HCl monitors are required for Coleman One (1) for the common WFGD stack and one (1) for each unit bypass stack

The compliance strategy above has identical SO2 control technologies as the CSAPR 2014 approach but the NOX technologies have been altered to include a second SCR at Green 1. With these upgrades BREC will be approximately 394 tpy below the projected NAAQS NOX allocations. As with the 2014 CSAPR strategy, necessary upgrades for MACT have also been accounted for given the proposed CSAPR modifications are put in place.

A sensitivity analysis was also conducted on the NAAQS technologies as a whole. The "break even" credit cost for SO2 was identical to the CSAPR approach. Holding SO2 credit prices constant, the "break even" credit cost for NOX was found to be approximately $4,713. As with the CSAPR approach, the suggested NAAQS strategy is more sensitive to the price of NOX credits as a result of the large lifetime costs associated with NOX control technologies. Implementing a strategy to comply with future predicted regulations is a high risk approach and may not offer any pay back over the project lifetime. If a reduction such as those predicted for NAAQS is executed by EPA, a strategy similar to that shown in Table 5-10 may be warranted.

5.2.4 316(b) Impingement Mortality and Entrainment

The circular replacement screens (WIP) with fish pumps, traveling screens with fish return system and the cylindrical wedgewire screen are all considered to be technically acceptable technologies for meeting the anticipated 316(b) regulation. Since the rotating circular replacement screens (WIP) with fish pumps had the lowest capital impact also had the lowest O&M cost, an NPV analysis was not conducted. Therefore, installation of the rotating screens (WIP) with fish pump technology is recommended as the compliance technology to meet the pending 316(b) regulations.

5.2.5 Coal Combustion Residuals

Both the remote submerged scraper conveyor (SSC) and dewatering bin systems are considered technically acceptable technologies. The SSC has higher O&M costs than a dewatering bin system due to higher maintenance costs as well as additional operators and equipment needed for front end loader operation to load ash into trucks for transport. Net present value comparison is detailed as follows:

Table 5-11 — Bottom Ash Conversion Lifetime Cost Comparison

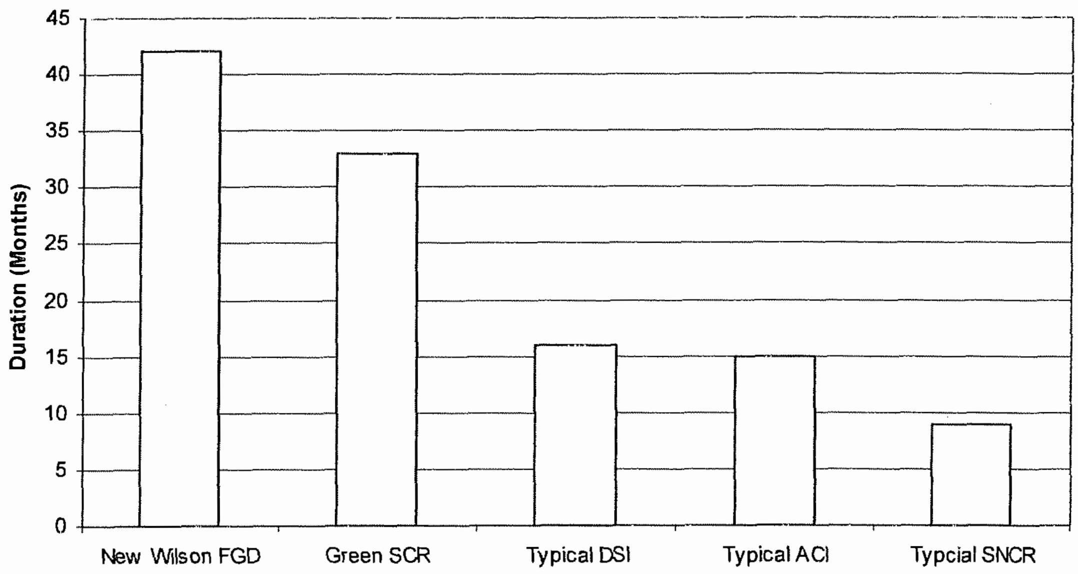
Station	Remote SSC NPV (2011$ Millions)	Dewatering Bin NPV (2011$ Millions)
Coleman	45.6	50.1
HMP&L	34.1	39.6
Green	37.0	41.6

Based on this comparison, installation of remote SSC systems are recommended as the compliance technology selection at Coleman, HMP&L and Green for pending CCR regulations.

5.3 COMPLIANCE TECHNOLOGY PROJECT SCHEDULES

For each of the major anticipated modifications proposed, a level 1 project schedule was developed. The schedules show major administrative, engineering, procurement, construction and start up tasks. These schedules are based on S&L's past project experience and current 2011 equipment lead times. The anticipated durations, milestones and links were developed based on a minimal contracts approach to project execution. Schedules for installation of a new absorber at Wilson, an SCR at Green (1 or 2) and typical schedules for installation of DSI and ACI systems are provided in Appendix 4. A summary of anticipated durations from the start of engineering to system start up for the four major technologies is provided in Figure 5-1 below.

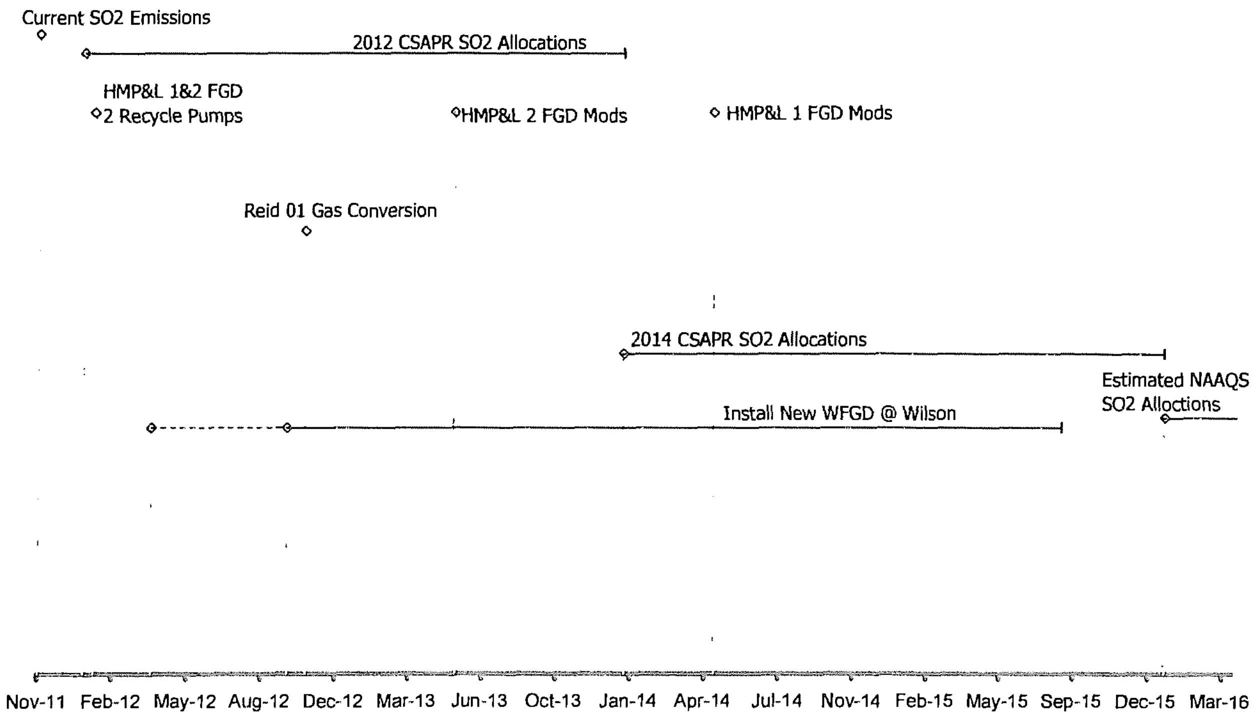
Figure 5-1 — Project Duration by Technology



5.3.1 Technology Implementation Timeline

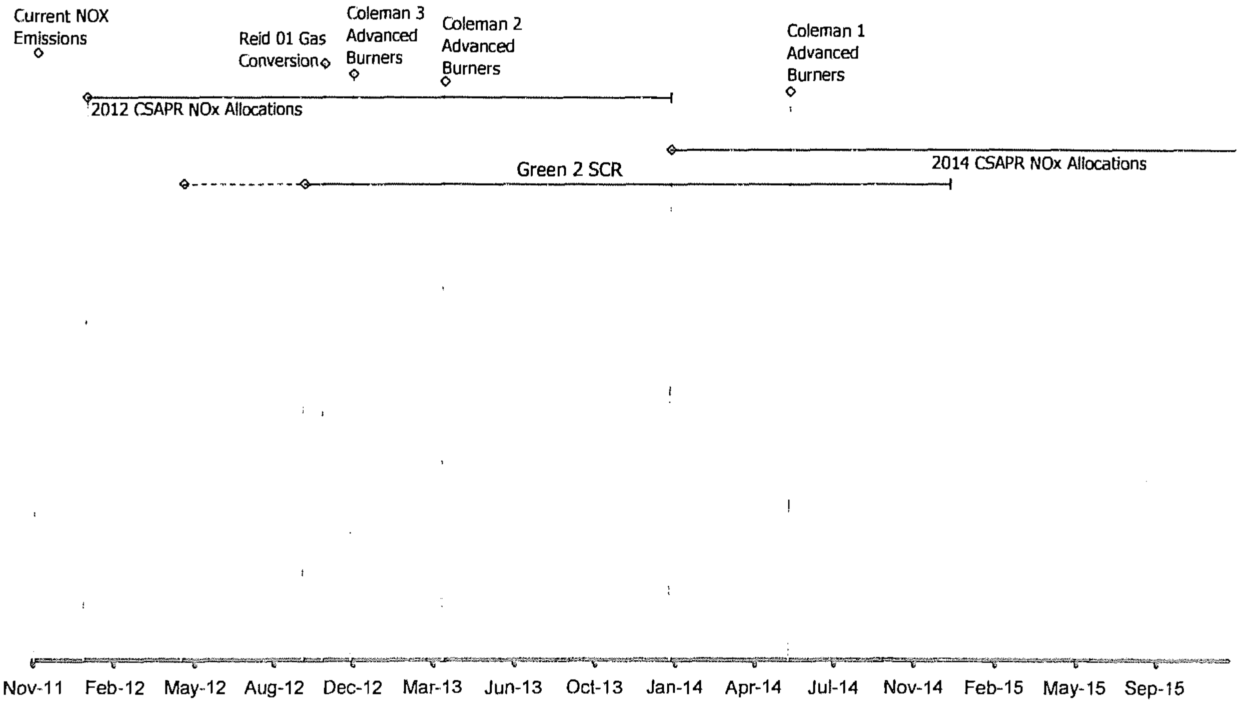
In order to meet the upcoming 2012 and 2014 CSAPR, 2015 EGU MACT and potential 2016 NAAQS dates, a timeline showing when each technology should be implemented at the various BREC sites was developed for the two strategies detailed above. The timelines show the desired installation dates as well as the overall surplus or deficit of credits that will need to be bought for compliance or overall surplus available to sell to other Group 1 states.

Figure 5-2 — CSAPR / NAAQS SO_2 Compliance Technology Timeline



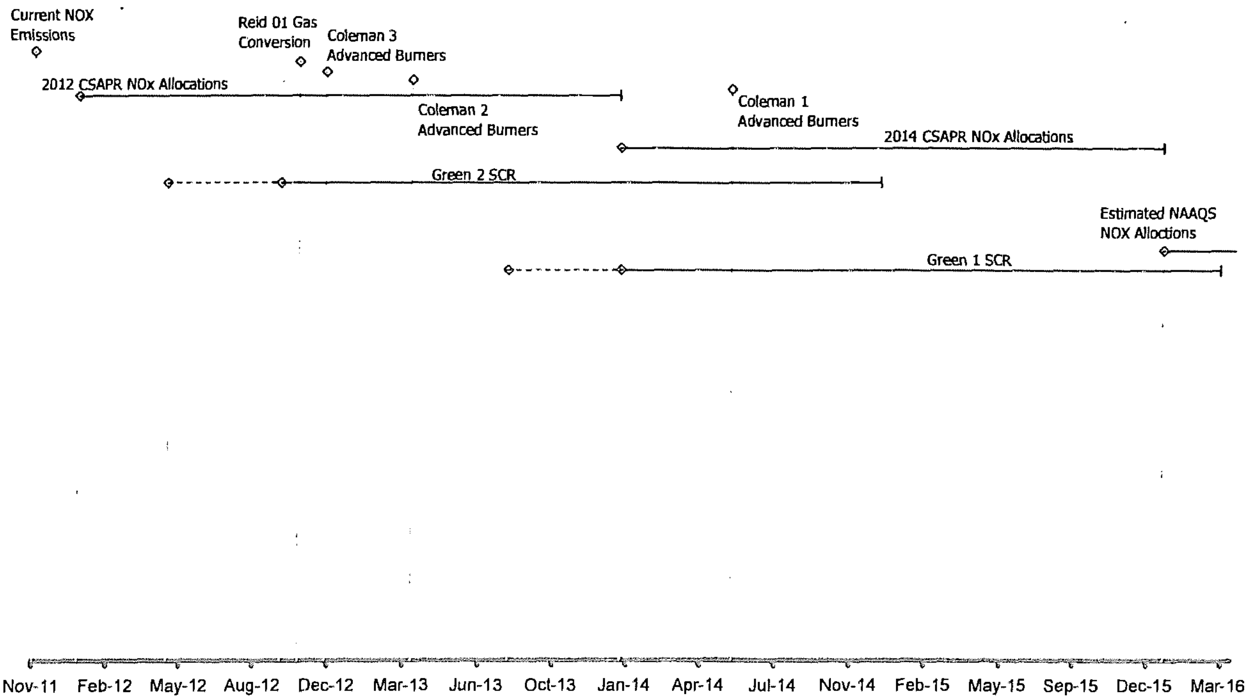
Based on an estimated equipment award date of October 1, 2012, it is anticipated that the new Wilson scrubber would be in service by September 2015. Reid 1 gas conversion would take place during the next major scheduled outage in October 2012. Operating the HMP&L scrubbers with two recycle pumps would start in January 2012 with installation of spare recycle pumps and ID fan upgrades taking place during the March-May 2013 HMP&L 2 and April–May 2014 HMP&L outages. During periods of high load demand and/or high ambient temperatures the HMP&L Units may need to derate or return to single-pump WFGD operation to avoid overheating the existing fan motors until the fan upgrades are completed. Project durations for typical ACI and DSI technologies are 15 and 16 months, respectively, and should be completed before the MACT compliance deadline. In addition, the anticipated ESP modifications have not been shown in this timeline but should be completed based on available outage schedules to meet the anticipated MACT compliance date of January 1, 2015.

Figure 5-3 — CSAPR NO_X Compliance Technology Timeline



Installation advanced burners at all Coleman units, an SCR at Green 2 and converting Reid 1 to natural gas will reduce annual NO_X emissions below BRECs 2012 CSAPR allocation level. The Reid 1 gas conversion would take place during the next major outage in October 2012. The Coleman advanced burner upgrades will take place in 2013, 2014, and 2015 according to BREC's schedule already in place. Completion of the Green 2 SCR for 2014 CSAPR compliance is based on an equipment award date of October 1, 2012.

Figure 5-4 — NAAQS NO_X Compliance Technology Timeline

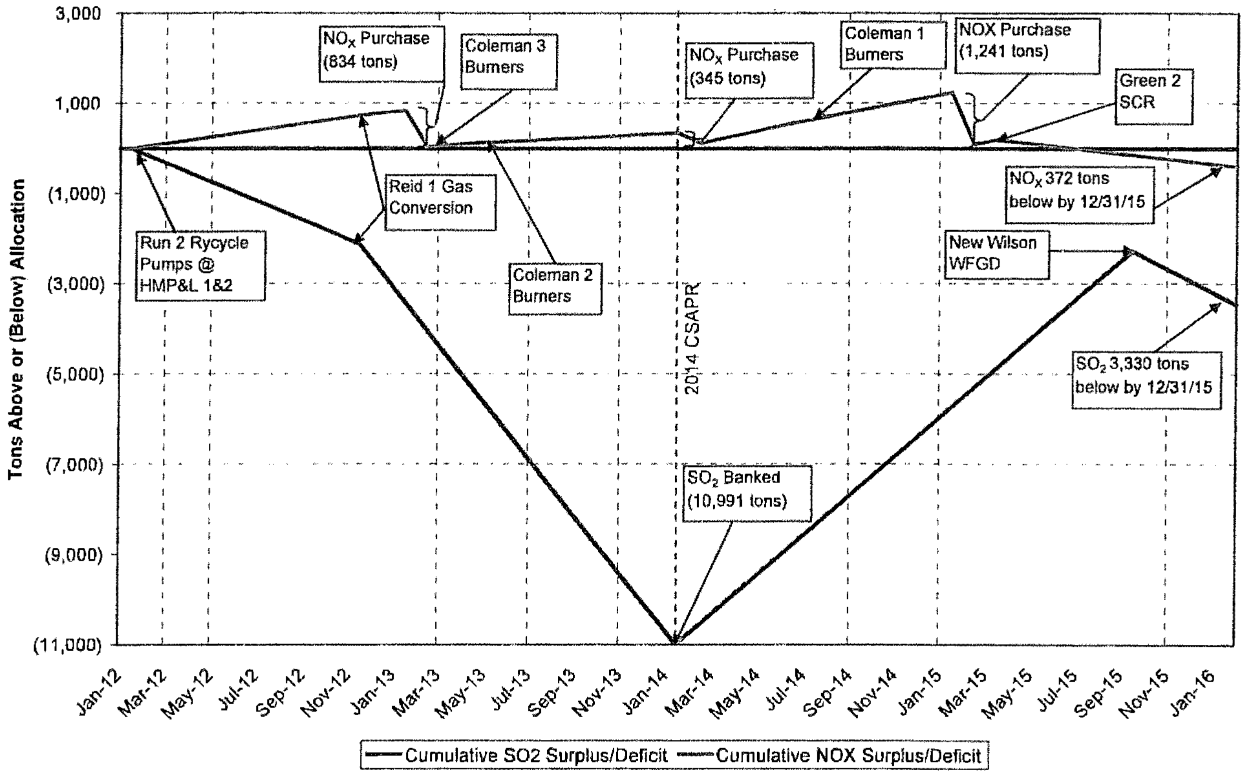


To comply with the potential 20% reductions foreseen by NAAQS, additional technologies would be required. Installation of an SCR at Green 1 will be responsible for making up the additional 1,349 tpy of required NO_X reductions. Engineering of the Green 1 SCR would need to start in August 2013 in order to comply with the predicted 2016 allocations.

5.3.2 Banked and Purchased Credits for Strategies

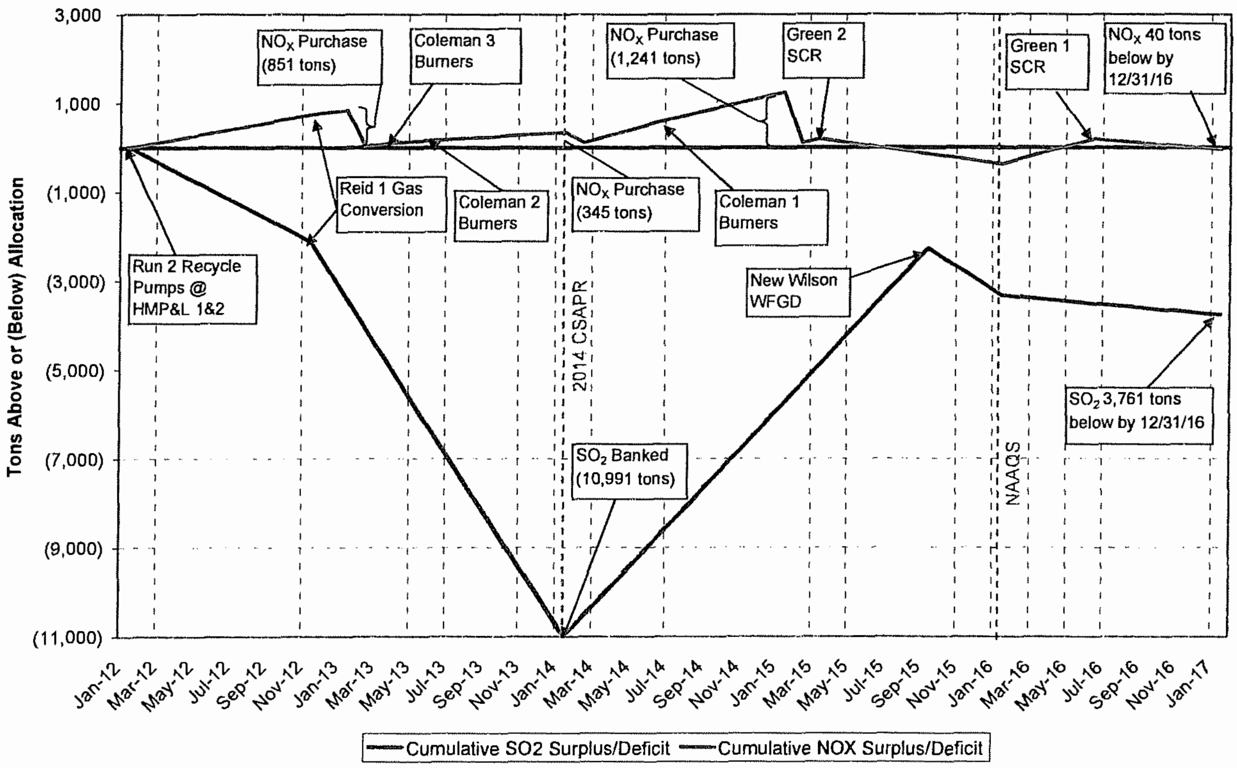
Based on the implementation strategy timeline detailed above, the cumulative deficit or surplus generated by implementing the proposed strategies compared to the 2012 and 2014 CSAPR and projected 2016 NAAQS was determined. Figure 5-5 below shows the total cumulative SO_2 and NO_X emission deficits and/or surpluses compared to CSAPR allocations from January 2012 through December 2015.

Figure 5-5 — Cumulative Emissions Above or Below CSAPR SO_2 and NO_X Allocations



Implementing the compliance schedule shown in Figure 5-2 and Figure 5-3, BREC will consistently have adequate SO_2 credits to maintain operation within their CSAPR allocation limits. NO_X emissions continue to be above allocation limits each year until startup of the Green 2 SCR. Based on these completion dates for NO_X technologies, BREC will be able to meet their 2014 CSAPR allocations limits by 2015 but will need to purchase additional credits to cover surplus emissions for 2012 (843 tons), 2013 (345 tons) and 2014 (1,241 tons). Starting in 2015 with startup of the Green 2 SCR, the NO_X control strategies will lower emission levels below the 2014 CSAPR allocations. Implementing the WFGD modifications at HMP&L and converting Reid 01 will reduce SO_2 emission below the 2012 levels and allow BREC to bank approximately 11,000 credits over two years (2012-2013) for use to offset yearly overages while the new Wilson FGD is being constructed.

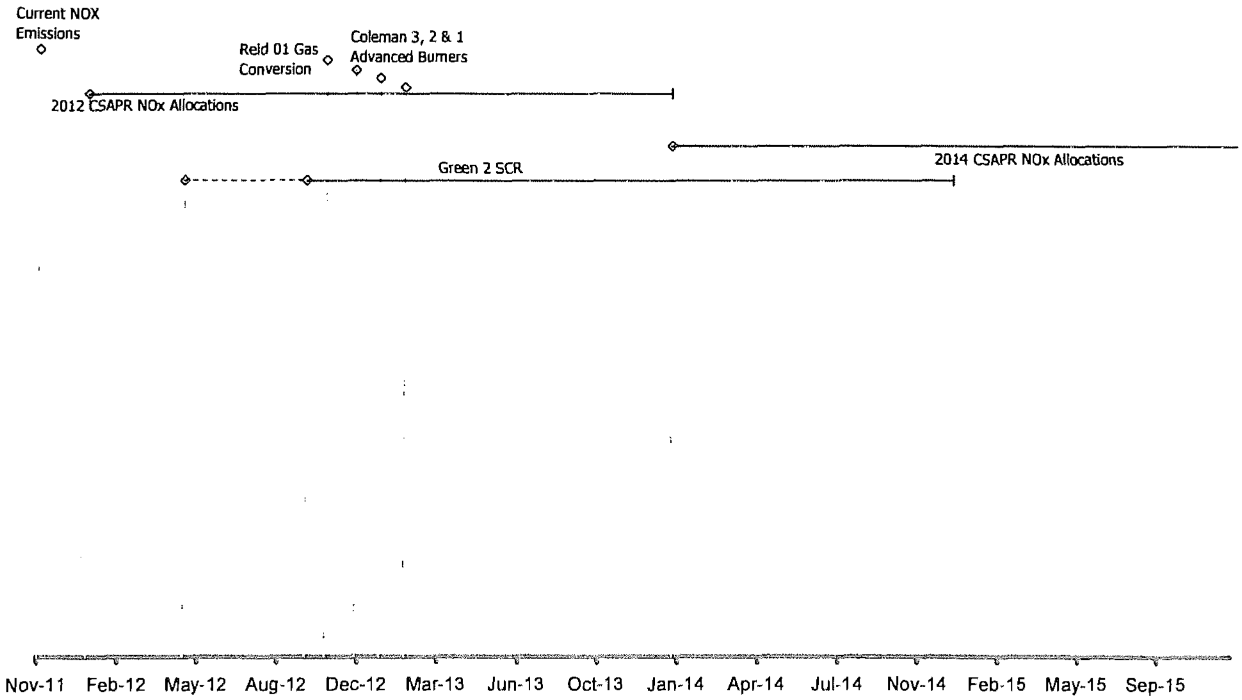
Figure 5-6 — Cumulative Emissions Above or Below NAAQS SO_2 and NO_X Allocations



Using the installation timelines shown in Figure 5-2 and Figure 5-4, BREC will be able to meet their predicted 2016 NAAQS allocations. Both NO_X and SO_2 will remain at levels below the anticipated NAAQS limits after 2014. NO_X credit purchase of approximately 851, 345 and 1,241 tons would be required for 2012, 2013 and 2014 respectively.

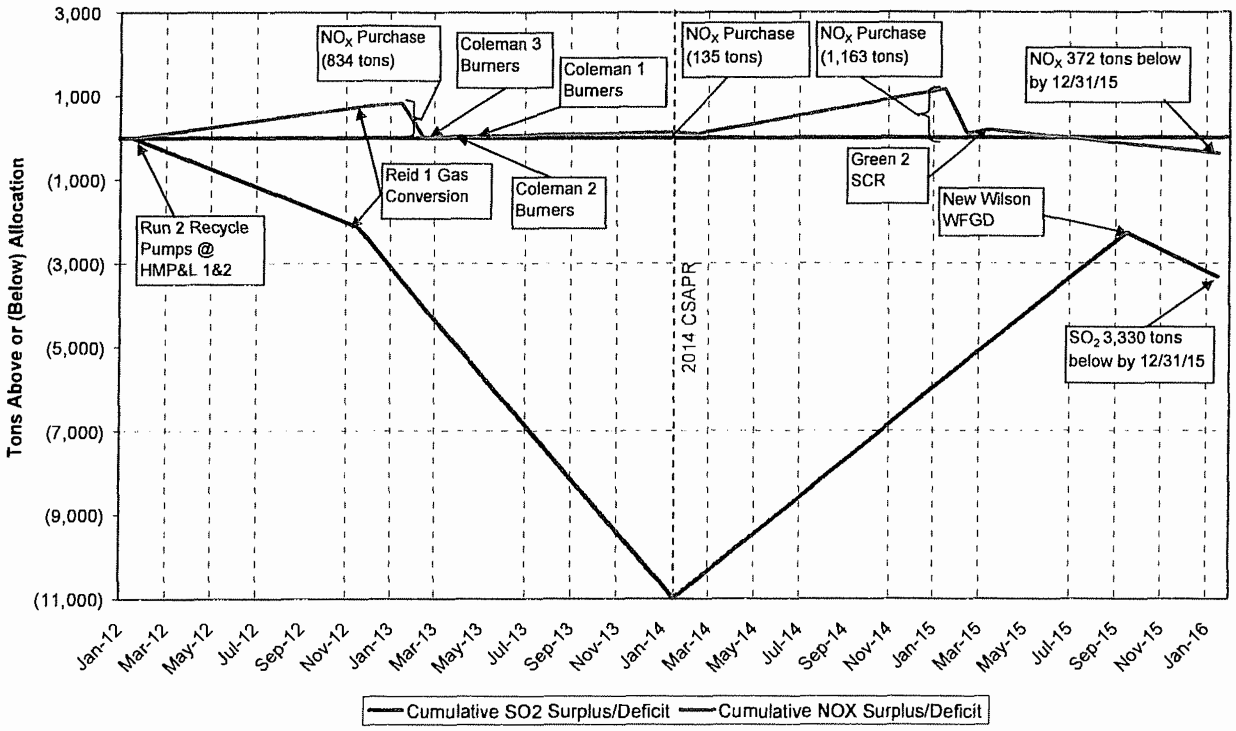
Cumulative deficits and surpluses shown in Figure 5-5 and Figure 5-6 represent installation and startup dates that parallel BREC's current outage schedules. To minimize potential NO_X overages and purchase of credits, BREC should consider adjusting some planned outage dates. Figure 5-7 below adjusts post 2012 scheduled outages to reduce yearly NO_X overages after 2013.

Figure 5-7 — CSAPR NO_X Compliance Technology Timeline (Adjusted)



Adjusting the installation date for the Coleman 1 and 2 advanced burners to the start of 2013 will reduce BREC's overall exceedence of their 2013 and 2014 NO_X allocations by 210 and 78 tons and help to avoid uncertainties of the credit market. The resulting cumulative surplus and deficit associated with implementing the above NO_X timeline and the previous SO_2 timeline of Figure 5-2 is shown in Figure 5-8 below.

Figure 5-8 — Cumulative Emissions Above or Below CSAPR SO_2 & NO_X Allocations (Adjusted)



Purchase of approximately 834, 135 and 1,163 tons of NO_X credits will be needed to offset excess 2012, 2013 and 2014 emissions. Installation of third generation low-NO_X burners at Coleman 1, 2 and 3 and start up of the Green 2 SCR in 2015 will enable BREC to achieve NO_X compliance for 2015. After switching the HMP&L scrubbers to operate with two recirculation pumps, SO_2 emissions will continuously be lower than BREC's 2012 allocations and should be banked to offset excess emissions in 2014 and 2015 before the new Wilson WFGD starts up.

Should BREC exceed their allowance, they will be required to settle any credit deficits on a calendar year basis. If below their yearly allocations, BREC will have the option to either sell or bank their excess credits for use at a later date. Credits that have been banked do not expire and can be used to offset in any future CSAPR emission overage. Table 5-12 below shows the anticipated excess or shortage of credits per year (2012-2017) for each of the proposed strategies and installation schedules.

Table 5-12 — Fleet-Wide Yearly Allocation Surplus and Deficit

Year	End of Year SO_2 Surplus or (Deficit)			End of Year NO_X Surplus or (Deficit)		
	CSAPR	CSAPR (Adjusted)	NAAQS	CSAPR	CSAPR (Adjusted)	NAAQS
2012	3,385	3,385	3,385	(834)	(834)	(834)
2013	7,606	7,606	7,606	(345)	(135)	(345)
2014	(5,229)	(5,229)	(5,229)	(1,241)	(1,163)	(1,241)
2015	(2,433)	(2,433)	(2,433)	372	372	372
2016	3,160	3,160	431	679	679	(332)
2017	3,160	3,160	431	679	679	394
TOTAL	9,650	9,650	4,192	(688)	(401)	(1,986)

Regardless of the approach taken, BREC will need to purchase credits to offset excess NO_X emissions in 2012, 2013 and 2014. Should BREC choose to implement the "CSAPR Adjusted" implementation schedule, the early burner upgrades at Coleman 1 and 2 will reduce necessary credit purchases by a total of 288 tons for 2013 and 2014. The NAAQS approach requires NO_X credit purchases in 2012, 2013, and 2014 but will provide excess credits to be banked in 2016 to offset potential overages in 2017. SO_2 credit surplus and deficit remains the same regardless of strategy. Excess SO_2 credits from 2012 and 2013 will need to be banked to offset deficits in 2014 and 2015. Startup of the new Wilson WFGD will return overall fleet-wide SO_2 emissions to below their allocations by 2016.

Last page of Section 5.

6. CONCLUSIONS AND RECOMMENDATIONS

Based on the results of the technology screening and cost estimating performed in this study, the recommended compliance strategies for meeting future regulations on air quality, coal combustion residual handling, and 316(b) impingement mortality and entrainment are summarized as follows:

6.1 SULFUR DIOXIDE

The projected emission limit under the final version 2014 Cross-States Air Pollution Rule (CSAPR) is 13,643 tpy for the BREC fleet. Using this limit and the annual average heat input, the calculated emission rate for 2014 is 0.192 lb/MMBtu compared to the current fleet-wide rate of 0.384 lb/MMBtu. A total fleet-wide reduction in SO_2 emissions of 50% is needed to comply with the 2014 allocations. This limit will require BREC to upgrade existing WFGD systems and address units such as Reid 01 which has no SO_2 control technology in place. After completing an NPV comparison of the various improvements available, the most economical solutions to reduce BREC's emissions to the 2014 limits were chosen.

BREC should replaced the existing Wilson horizontal scrubber which has been operating at about 91% removal efficiency with new absorber vessel capable of increasing removal rates to 99% and reduce emission by approximately 8,400 tpy. Operating the existing HMP&L scrubbers with two (2) recirculation pumps will increase removal efficiency to about 97% and reduce emissions by nearly 3,350 tpy. It's recommended that HMP&L install third recycle pump in each absorber to increase redundancy and tip the existing ID fans to offset the increased pressure drop caused by an increase in slurry flowrate. Converting Reid 01 to natural gas will further reduce fleet-wide SO_2 emissions by 5,065 tpy. BREC should also return the Coleman scrubber back to as-designed operation to achieve 96% removal rates, perform a condition assessment to determine how best to improve reliability and consider implementing simultaneous Coleman unit outages when the WFGD is offline to avoid bypass operation. Implementing the modifications given in Table 6-1 below, BREC will be under their 2014 CSAPR allocation allowance and a potentially forthcoming ruction of 20% for NAAQS compliance.

Table 6-1 — SO_2 Compliance Summary

Unit	Baseline Heat Input (MMBtu)	Baseline SO_2 Emissions (tpy)	Current Annual SO_2 Emission Rate (lb/MMBtu)	Technology Selection	Estimated New SO_2 Emissions (tpy)	Estimated New Annual SO_2 Emission Rate (lb/MMBtu)	Net Present Value (2011$ Million)
Coleman Unit C01	11,784,789	2,331	0.396	Return to As-Designed Operation	1,473	0.250	N/A
Coleman Unit C02	11,787,242	2,411	0.409	Return to As-Designed Operation	1,473	0.250	N/A
Coleman Unit C03	12,570,106	2,406	0.383	Return to As-Designed Operation	1,571	0 250	N/A
Wilson Unit W01	37,043,481	9,438	0.510	New Tower Scrubber - 99% removal	1,049	0.057	$82.5
Green Unit G01	20,128,359	1,873	0.186	None	1,873	0.186	N/A
Green Unit G02	20,347,531	1,414	0.139	None	1,414	0.139	N/A
HMP&L Unit H01	12,823,005	2,227	0.347	Run both pumps install third pump as spare	788	0.123	-$2.1
HMP&L Unit H02	13,214,893	2,745	0.415	Run both pumps install third pump as spare	835	0.126	-$2.1
Reid Unit R01	2,240,807	5,066	4.522	Natural Gas with Existing Burners	1	0.001	$8.9
Reid Unit RT	87,379	5	0.117	None	5	0.117	N/A
TOTAL	142,027,592	29,916	0.421	N/A	10,482	0.148	$87.2

To achieve CSAPR compliance BREC should execute a fleet-wide project schedule similar to that show in Figure 5-2. Operating the HMP&L WFGDs with both recirculation pumps starting in January 2012 along with converting Reid 1 to natural gas in November 2012 will result in excess allocations that can be used to offset SO_2 deficits after the 2014 allocations go into effect until startup of the new Wilson scrubber in 2015. It is anticipated that the new Wilson scrubber will take forty-two months from the start of engineering to the startup and would need to be in service by the end of 2015 to avoid any potential credit purchase.

6.2 ACID GAS MITIGATION (SO_3 AND HCL)

In order to promote effective mercury capture, DSI systems should be installed at each unit where ACI systems are installed. Activated carbon requires SO_3 concentrations to be in the range of 3-5 ppm for maximum effectiveness. At these concentration levels, ESP performance should be unaffected by the reduced SO_3 and remain near their current removal efficiencies. Installation of a DSI system typically takes 16 months from the start of engineering to system operation. Lifetime cost of the recommended sorbent injection systems is included in the particulate matter strategy summary of Section 6.5.

Although each of the BREC units currently has HCl emissions that are below the proposed MACT limits, some facilities will not have SO_2 emission rates low enough to be used as a surrogate for MACT acid gas compliance. In cases where SO_2 emission rates are greater that 0.20 lb/MMBtu (Coleman), HCl stack monitors will be required to demonstrate compliance. Net present value for a monitor is approximately $414k.

6.3 NITROGEN OXIDES

BREC's NO_X allocation under the final version 2014 CSAPR is 10,142 tpy for the fleet. Using this limit and the annual average heat input, the calculated emission rate for 2014 is 0.149 lb/MMBtu compared to the current fleet-wide rate of 0.177 lb/MMBtu. A total fleet-wide reduction in SO_2 emissions of 16% is needed to comply with the 2014 allocations. To meet their allocation limit BREC will need to install an SCR at Green, convert Reid 1 to natural gas and upgrade existing Low-NO_X burners at Coleman. After completing an NPV comparison of the various improvements available, the most economical solutions to reduce BREC's emissions to the 2014 limits were chosen. BREC should install SCR system at Green 2 to reduce emission by 1,843 tpy. Planned upgrades at the three Coleman units to third generation Lox-NO_X burners will provide 549 tpy of reduction and converting Reid to natural gas will provide an additional 220 tpy reduction. Implementing all of these modifications will reduce BREC's annual NO_X emissions to approximately 9,462 tpy and achieve compliance with their 2014 CSAPR allocations. Table 6-2 provides a summary of the suggested modifications for compliance.

Table 6-2 — NO_X CSAPR Compliance Summary

Unit	Baseline Heat Input (MMBtu)	Baseline NO_X Emissions (tpy)	Current Annual NO_X Emission Rate (lb/MMBtu)	Technology Selection	Estimated New NO_X Emissions (tpy)	Estimated New Annual NO_X Emission Rate (lb/MMBtu)	Net Present Value (2011$ Million)
Coleman Unit C01	11,254,853	1,858	0.330	Advanced Burners	1,672	0.297	$0.32
Coleman Unit C02	9,544,382	1,585	0.332	Advanced Burners	1,427	0.299	$0.32
Coleman Unit C03	12,195,952	2,044	0.335	Advanced Burners	1,840	0.302	$0.32
Wilson Unit W01	36,221,670	934	0.052	None	934	0.052	N/A
Green Unit G01	19,866,020	2,050	0.206	None	2,050	0.206	N/A
Green Unit G02	20,128,970	2,168	0.215	SCR @ 85% Removal	325	0.032	$43.9
HMP&L Unit H01	13,003,466	460	0.071	None	460	0.071	N/A
HMP&L Unit H02	12,118,692	418	0.069	None	418	0.069	N/A
Reid Unit R01	1,962,424	512	0.522	Natural Gas with Existing Burners	292	0.298	See SO_2
Reid Unit RT	126,361	45	0.708	None	45	0.708	N/A
TOTAL	136,422,791	12,074	0.177	N/A	9,462	0.139	$44.9

In order to achieve compliance with potential NAAQS emission reductions, BREC would need to alter their compliance strategy. Assuming that an additional 20% reduction beyond the 2014 CSAPR allocations will be required, BREC will need to reduce its fleet-wide NO_X emission rate from 0.177 lb/MMBtu to 0.119 lb/MMBtu in order to meet their allocation of 8,114 tpy. Advanced burner upgrades would be required at all three Coleman units and both Green units would require a SCRs. Like the CSAPR approach, converting Reid 1 to natural gas would provide additional reduction. A summary of the suggested modifications, net present value and resulting emissions for this approach are provided in Table 6-3 below.

Table 6-3 — NO_X NAAQS Compliance Summary

Unit	Baseline Heat Input (MMBtu)	Baseline NO_X Emissions (tpy)	Current Annual NO_X Emission Rate (lb/MMBtu)	Technology Selection	Estimated New NO_X Emissions (tpy)	Estimated New Annual NO_X Emission Rate (lb/MMBtu)	Net Present Value (2011$ Million)
Coleman Unit C01	11,254,853	1,858	0.330	Advanced Burners	1,672	0.297	$0.32
Coleman Unit C02	9,544,382	1,585	0.332	Advanced Burners	1,427	0.299	$0.32
Coleman Unit C03	12,195,952	2,044	0.335	Advanced Burners	1,840	0.302	$0.32
Wilson Unit W01	36,221,670	934	0.052	None	934	0.052	N/A
Green Unit G01	19,866,020	2,050	0.206	SCR @ 85% Removal	307	0.031	$46.5
Green Unit G02	20,128,970	2,168	0.215	SCR @ 85% Removal	325	0.032	$43.9
HMP&L Unit H01	13,003,466	460	0.071	None	460	0.071	N/A
HMP&L Unit H02	12,118,692	418	0.069	None	418	0.069	N/A
Reid Unit R01*	1,962,424	512	0.522	Natural Gas with Existing Burners	292	0.298	See SO_2
Reid Unit RT	126,361	45	0.708	None	45	0.708	N/A
TOTAL	136,422,791	12,074	0.177	N/A	7,720	0.113	$91.4

Project schedules and implementation timelines for the recommended NO_X control modifications are shown in Figure 5-7. These strategies produce NO_X allocation deficits in 2012, 2013 and 2014 which will need to be purchased from other Group 1 utilities. Installation of new advanced low-NO_X burners at Coleman 1, 2, and 3 and the startup of the Green 2 SCR reduce emissions sufficiently for 2015 compliance. To meet potential NAAQS reductions, an implementation timeline similar to Figure 5-4 should be executed.

6.4 MERCURY

Currently the only BREC units that are compliant with the proposed MACT regulation of 1.2 lb/TBtu are HMP&L 1 and 2. All units at Coleman, Wilson and Green will require ACI systems to achieve compliance by 2015. Emission reductions of 66% at Coleman, 32% at Wilson, 61% at Green 1 and 53% at Green 2 will be needed. If any unit is converted to natural gas it will no longer be required to meet the MACT Hg requirements. Typical duration for installation of an ACI system is fifteen (15) months from the start of engineering to system startup. BREC should install the ACI systems across their fleet before the anticipated MACT compliance date of January 1, 2015. A summary of current mercury emission levels, proposed compliance technology and net present value for the recommended modifications is provided below.

Table 6-4 — MACT Hg Compliance Summary

Unit	Baseline Elemental Hg Emission Rate (lb/TBtu)	Baseline Oxidized Hg Emission Rate (lb/TBtu)	Baseline Total Hg Emission Rate (lb/TBtu)	Required Percent Reduction for MACT Compliance	Technology Selection	NPV (2011$ Million)
Coleman Unit C01	2.67	0.85	3.52	66%	Activated Carbon Injection	$11.9
Coleman Unit C02						$11.9
Coleman Unit C03						$11.9
Wilson Unit W01	1.56	0.21	1.77	32%	Activated Carbon Injection	$26.7
Green Unit G01	2.73	0.36	3.09	61%	Activated Carbon Injection	$15.3
Green Unit G02	2.46	0.12	2.58	53%	Activated Carbon Injection	$15.3
HMP&L Unit H01	0.34	0.28	0.62	N/A	None	N/A
HMP&L Unit H02	0.22	0.24	0.47	N/A	None	N/A
Reid Unit R01	N/A	N/A	6.5	82%	Natural Gas Conversion	N/A
TOTAL						$93.0

6.5 PARTICULATE MATTER AND ACID GAS CONTROL

PM emissions are made up of condensable emissions and filterable emissions. The existing ESPs and WFGD systems at Wilson and Green 1 and 2 are currently achieving filterable and condensable emissions below the anticipated MACT level of 0.030 lb/MMBtu. Total particulate emissions at Coleman and HMP&L are above the MACT proposed limit and will required upgrades. Current emission levels, recommended modifications and net present value for each station are summarized below.

Table 6-5 — MACT TPM Compliance Summary

Unit	Baseline Filterable PM Emission Rate (lb/MMBtu)	Baseline Condensable PM Emission Rate (lb/MMBtu)	Baseline Total PM Emission Rate (lb/MMBtu)	Required Percent Reduction for MACT Compliance	Technology Selection	Net Present Value (2011$ Million)
Coleman Unit C01	0.0220	0.0178	0.0398	25%	Hydrated Lime DSI & ESP Upgrades	$10.3
Coleman Unit C02						$10.3
Coleman Unit C03						$10.3
Wilson Unit W01	0.00912	0.01043	0.0196	N/A	Low Oxidation Catalyst & ESP Upgrades	$11.2
Green Unit G01	0.0084	0.0111	0.0195	N/A	Hydrated Lime DSI & Potential ESP Upgrades	$11.2
Green Unit G02	0.0046	0.0123	0.0169	N/A	Hydrated Lime DSI & Potential ESP Upgrades	$11.2
HMP&L Unit H01	0.0177	0.0142	0.0319	6%	Hydrated Lime, Low Oxidation Catalyst & ESP Upgrades	$11.2
HMP&L Unit H02	0.0120	0.0204	0.0324	7%	Hydrated Lime, Low Oxidation Catalyst & ESP Upgrades	$11.2
Reid Unit R01	0.269	N/A	>0.030	90%	Natural Gas Conversion	N/A
TOTAL						$86.9

Although current Wilson and Green TPM emission levels are below 0.030 lb/MMBtu, upgrades to the ESPs will likely be required to offset increased particulate loading from the ACI and DSI systems that are required for mercury control. In addition, installation of DSI systems at HMP&L and Coleman will reduce the high condensable emissions while minimally increasing filterable emissions. Testing should be conducted at all units to determine how the existing ESP performance is affected by activated carbon and sorbent injection systems before any upgrades.

6.6 COOLING WATER INTAKE IMPINGEMENT MORTALITY AND ENTRAINMENT (316(b))

Proposed EPA 316(b) regulations for cooling water intakes will limit intake velocities to 0.5 fps or require cooling system modifications to limit impingement mortality of fish, eggs, larvae, and other aquatic organisms to a maximum of 12% annual average. In addition, the compliance technology installed should be demonstrated to be a Best Technology Available (BTA) for entrainment reduction. This study evaluated several different technologies that provide for compliance with these proposed regulations, including new screen designs and conversion to closed cycle cooling. Since the proposed regulations do not mandate a conversion to closed cycle cooling, it is recommended that replacement intake screens be installed. The recommended screen technology based on an evaluation of capital and O&M costs is a rotating circular intake screen with fish pumps to meet the expected impingement mortality reduction. The expected capital and O&M cost of these screens is provided in the table below.

Table 6-6 — 316(b) Compliance Summary

Unit	Selected Technology	Estimated Capital Cost ($2011 Million)	Estimated O&M Cost ($2011 Million)
Coleman Unit C01	Rotating Circular Intake Screen with Fish Pump	$1.33	$0.25
Coleman Unit C02		$1.33	$0.25
Coleman Unit C03		$1.33	$0.25
Sebree		$2.05	$0.37

It is recommended that BREC engage a screen supplier to discuss the site specific installation requirements and compliance verification methods for new screen technology that will meet the proposed EPA 316 (b) requirements. Ongoing EPA 316(b) testing that is being performed in the industry on the various new designs of replacement screens should be monitored as well.

6.7 COAL COMBUSTION RESIDUAL HANDLING AND DISPOSAL

Two alternate regulations for the management of CCRs including fly ash, WFGD waste product, and bottom ash, have been issued for public comment. Under the first proposal, EPA would list these residuals as special wastes under the hazardous waste provisions of Subtitle C of the Resource Conservation and Recover Act (RCRA). Under the second proposal, EPA would regulate coal ash under Subtitle D of RCRA, the section for non-hazardous wastes. It is expected that the less stringent Subtitle D regulations will be promulgated, which will result in additional O&M cost for landfilling costs due to Subtitle D requirements for lining of landfills and ongoing groundwater monitoring. Although continued operation of the existing bottom ash dewatering ponds may be possible under the new regulations, this is not expected to be practical due to requirements for pond modifications (liner and ground water monitoring system installation) as well as pending wastewater discharge standards that will likely necessitate treatment or elimination of ash pond discharge streams. As such, a conversion to a dry bottom ash system using remote submerged scraper conveyors (SSCs) is recommended. The resulting capital costs associated with remote SSC installation and O&M costs is estimated and provided below. Depending on the local landfill options available to BREC under Subtitle D, additional CCR disposal O&M costs of approximately $2.50/ton may be incurred due to liner and groundwater monitoring requirements that will be imposed on landfill operators.

Table 6-7 — CCR Compliance Summary

Station	Technology Selected	NPV (2011$ Millions)
Coleman	Dry Bottom Conversion – Remote SSC & Fly Ash Conversion to Dry Pneumatic	$45.6
Wilson	None	N/A
Green	Dry Bottom Conversion – Remote SSC	$37.0
HMP&L	Dry Bottom Conversion – Remote SSC	$34.1
Reid	None	N/A

Last page of Section 6.

Appendix 1 – Expanded Compliance Strategy Matrices

Technology Selection & Results - CSAPR & MACT

BREC Unit	Technology Selection: CSAPR - Selection: SO_2	CSAPR - Selection: NO_x	MACT - Selection: HCl	MACT - Selection: Hg	MACT - Selection: CPM	MACT - Selection: FPM
Coleman Unit C01	None**	Advanced Burners	HCl level is below anticipated MACT limits. Installation of an HCl monitor is needed since SO2 can not be used as a surrogate.***	Activated Carbon Injection	Hydrated Lime - DSI	Advanced Electrodes & High Frequency TR Sets
Coleman Unit C02	None**	Advanced Burners	HCl level is below anticipated MACT limits. Installation of an HCl monitor is needed since SO2 can not be used as a surrogate.***	Activated Carbon Injection	Hydrated Lime - DSI	Advanced Electrodes & High Frequency TR Sets
Coleman Unit C03	None**	Advanced Burners	HCl level is below anticipated MACT limits. Installation of an HCl monitor is needed since SO2 can not be used as a surrogate.***	Activated Carbon Injection	Hydrated Lime - DSI	Advanced Electrodes & High Frequency TR Sets
Wilson Unit W01	New Tower Scrubber - 99% removal	None	Higher L/G or new tower for increased SO2 removal to below 0.2 lb/mmBtu will permit reporting SO2 data as prima facia evidence of compliance with HCl emission limits	Activated Carbon Injection & New SCR Catalyst	Low Oxidation SCR catalyst + Hydrated Lime - DSI Control NH3 slip from SCR	Advanced Electrodes & High Frequency TR Sets
Green Unit G01	None	None	HCl Montior is not required since SO2 is below 0.2 lb/mmBtu	Activated Carbon Injection	Hydrated Lime - DSI	Potential ESP Upgrades Due to ACI and DSI
Green Unit G02	None	SCR @ 85% Removal	HCl Montior is not required since SO2 is below 0.2 lb/mmBtu	Activated Carbon Injection	Hydrated Lime - DSI	Potential ESP Upgrades Due to ACI and DSI
HMP&L Unit H01	Run both pumps & spray levels, install 3rd pump as spare	None	Higher L/G for increased SO2 removal to below 0.2 lb/mmBtu will permit reporting SO2 data as prima facia evidence of compliance with HCl emission limits	None needed due to oxidation across SCR and WFGD	Low Oxidation SCR catalyst + Hydrated Lime - DSI Control NH3 slip from SCR	ESP Maintenance / Possible Upgrade
HMP&L Unit H02	Run both pumps & spray levels, install 3rd pump as spare	None	Higher L/G for increased SO2 removal to below 0.2 lb/mmBtu will permit reporting SO2 data as prima facia evidence of compliance with HCl emission limits	None needed due to oxidation across SCR and WFGD	Low Oxidation SCR catalyst + Hydrated Lime - DSI Control NH3 slip from SCR	ESP Maintenance / Possible Upgrade
Reid Unit R01*	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners
Reid Unit RT	None	None	None	None	None	None
TOTAL						

BREC Unit	Emission Surplus / (Deficit) vs. Allocation: CSAPR II - 2014 (Tons) SO_2	CSAPR II - 2014 (Tons) NO_x	Projected NAAQS (Tons) SO_2	Projected NAAQS (Tons) NO_x	Capital Cost (Millions $): SO_2	NO_x	HCl	Hg	CPM	FPM	Total Projected Capital Cost (2011$)	Additional O&M Cost (Millions $): SO_2	NO_x	HCl	Hg	CPM	FPM	Fuel Cost Increase (2011$)	Total Yearly O&M Cost Increase (2011$)
Coleman Unit C01	(323)	(831)	(553)	(1000)	0.00	5.94	0.32	4.00	5.00	2.72	$18,000,000	0.00	0.00	0.03	0.81	0.27	0.09		$1,200,000
Coleman Unit C02	(323)	(585)	(553)	(753)	0.00	5.94	0.32	4.00	5.00	2.72	$18,000,000	0.00	0.00	0.03	0.81	0.27	0.09		$1,200,000
Coleman Unit C03	(345)	(942)	(590)	(1121)	0.00	5.94	0.32	4.00	5.00	2.72	$18,000,000	0.00	0.00	0.03	0.81	0.27	0.09		$1,200,000
Wilson Unit W01	2565	1711	1843	1162	139.00	0.00	0.00	4.50	6.50	4.54	$154,500,000	0.69	0.00	0.00	2.19	0.00	0.17		$3,100,000
Green Unit G01	91	(613)	(302)	(900)	0.00	0.00	0.00	4.00	5.00	3.34	$12,300,000	0.00	0.00	0.00	1.14	0.32	0.07		$1,500,000
Green Unit G02	357	1128	3	837	0.00	81.00	0.00	4.00	5.00	3.34	$93,300,000	0.00	2.16	0.00	1.14	0.32	0.07		$3,700,000
HMP&L Unit H01	463	456	213	273	3.15	0.00	0.00	0.00	6.00	2.50	$11,700,000	0.38	0.00	0.00	0.00	0.29	0.08		$800,000
HMP&L Unit H02	454	526	196	337	3.15	0.00	0.00	0.00	6.00	2.50	$11,700,000	0.38	0.00	0.00	0.00	0.29	0.08		$800,000
Reid Unit R01*	218	(132)	174	(164)	1.20						$1,200,000	(1.77)						$5,610,000	$3,800,000
Reid Unit RT	4	(39)	2	(40)	0.00						$0	0.00							$0
TOTAL	3161	680	432	(1349)							$339,000,000							$5,610,000	$17,300,000

*Note O&M savings associated with reduced maintenance and operational labor/parts have been extimated based on S&L expience due to lack of available operational data.
**Note SO2 emissions in this scenario have been adjusted to reflect recent data received from BREC confirming that the Coleman FGD is capable of producing emission rates of 0.25lb/MMBtu and reaching removal rates of approximately 95%.
***Note four (4) HCl monitors are required for Coleman. One (1) for the common WFGD stack and one (1) for each unit bypass stack.

Technology Selection & Results - NAAQS / CSAPR & MACT

BREC Unit	Technology Selection: CSAPR - Selection SO_2	CSAPR - Selection NO_x	MACT - Selection HCl	MACT - Selection Hg	MACT - Selection CPM	MACT - Selection FPM
Coleman Unit C01	None**	Advanced Burners	HCl level is below anticipated MACT limits. Installation of an HCl monitor is needed since SO2 can not be used as a surrogate.***	Fuel Additive & Activated Carbon Injection or Activated Carbon Injection	Hydrated Lime - DSI Control NH3 slip from ROTOMIX	Advanced Electrodes & High Frequency TR Sets
Coleman Unit C02	None**	Advanced Burners	HCl level is below anticipated MACT limits. Installation of an HCl monitor is needed since SO2 can not be used as a surrogate.***	Fuel Additive & Activated Carbon Injection or Activated Carbon Injection	Hydrated Lime - DSI Control NH3 slip from SNCR	Advanced Electrodes & High Frequency TR Sets
Coleman Unit C03	None**	Advanced Burners	HCl level is below anticipated MACT limits. Installation of an HCl monitor is needed since SO2 can not be used as a surrogate.***	Fuel Additive & Activated Carbon Injection or Activated Carbon Injection	Hydrated Lime - DSI Control NH3 slip from SNCR	Advanced Electrodes & High Frequency TR Sets
Wilson Unit W01	New Tower Scrubber - 99% removal	None	Higher L/G or new tower for increased SO2 removal to below 0.2 lb/mmBtu will permit reporting SO2 data as prima facia evidence of compliance with HCl emission limits	Activated Carbon Injection & New SCR Catalyst	Low Oxidation SCR catalyst + Hydrated Lime - DSI Control NH3 slip from SCR	Advanced Electrodes & High Frequency TR Sets
Green Unit G01	None	SCR @ 85% Removal	HCl Montior is not required since SO2 is below 0.2 lb/mmBtu	Activated Carbon Injection	Hydrated Lime - DSI	Potential ESP Upgrades Due to ACI and DSI
Green Unit G02*	None	SCR @ 85% Removal	HCl Montior is not required since SO2 is below 0.2 lb/mmBtu	Activated Carbon Injection	Hydrated Lime - DSI	Potential ESP Upgrades Due to ACI and DSI
HMP&L Unit H01	Run both pumps & spray levels, install 3rd pump as spare	None	Higher L/G for increased SO2 removal to below 0.2 lb/mmBtu will permit reporting SO2 data as prima facia evidence of compliance with HCl emission limits	None needed due to oxidation across SCR and WFGD	Low Oxidation SCR catalyst + Hydrated Lime - DSI Control NH3 slip from SCR	ESP Maintenance / Possible Upgrade
HMP&L Unit H02	Run both pumps & spray levels, install 3rd pump as spare	None	Higher L/G for increased SO2 removal to below 0.2 lb/mmBtu will permit reporting SO2 data as prima facia evidence of compliance with HCl emission limits	None needed due to oxidation across SCR and WFGD	Low Oxidation SCR catalyst + Hydrated Lime - DSI Control NH3 slip from SCR	ESP Maintenance / Possible Upgrade
Reid Unit R01*	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners
Reid Unit RT	None	None	None	None	None	None
TOTAL						

BREC Unit	CSAPR II - 2014 (Tons) SO_2	CSAPR II - 2014 (Tons) NO_x	Projected NAAQS (Tons) SO_2	Projected NAAQS (Tons) NO_x	Capital Cost (Millions $) SO_2	NO_x	HCl	Hg	CPM	FPM	Total Projected Capital Cost (2011$)	Additional O&M Cost (Millions $) SO_2	NO_x	HCl	Hg	CPM	FPM	Fuel Cost Increase (2011$)	Total Yearly O&M Cost Increase (2011$)
Coleman Unit C01	(323)	(831)	(553)	(1000)	3.93	5.94	0.32	4.00	5.00	2.72	$21,900,000	0.00	0.00	0.03	0.81	0.27	0.09		$1,200,000
Coleman Unit C02	(323)	(585)	(553)	(753)	3.93	5.94	0.32	4.00	5.00	2.72	$21,900,000	0.00	0.00	0.03	0.81	0.27	0.09		$1,200,000
Coleman Unit C03	(345)	(942)	(590)	(1121)	3.93	5.94	0.32	4.00	5.00	2.72	$21,900,000	0.00	0.00	0.03	0.81	0.27	0.09		$1,200,000
Wilson Unit W01	2565	1711	1843	1182	139.00	0.00	0.00	4.50	6.50	4.54	$154,500,000	0.69	0.00	0.00	2.19	0.00	0.17		$3,100,000
Green Unit G01	91	1130	(302)	842	0.00	81.00	0.00	4.00	5.00	3.34	$93,300,000	0.00	2.16	0.00	1.14	0.32	0.07		$3,700,000
Green Unit G02*	357	1128	3	837	0.00	81.00	0.00	4.00	5.00	3.34	$93,300,000	0.00	2.16	0.00	1.14	0.32	0.07		$3,700,000
HMP&L Unit H01	463	456	213	273	3.15	0.00	0.00	0.00	6.00	2.50	$11,700,000	0.38	0.00	0.00	0.00	0.29	0.08		$800,000
HMP&L Unit H02	454	526	196	337	3.15	0.00	0.00	0.00	6.00	2.50	$11,700,000	0.38	0.00	0.00	0.00	0.29	0.08		$800,000
Reid Unit R01*	218	(132)	174	(164)	1.20						$1,200,000	(1.77)						$5,610,000	$3,800,000
Reid Unit RT	4	(39)	2	(40)	0.00						$0	0.00							$0
TOTAL	3161	2422	432	394							$432,000,000							$5,610,000	$19,500,000

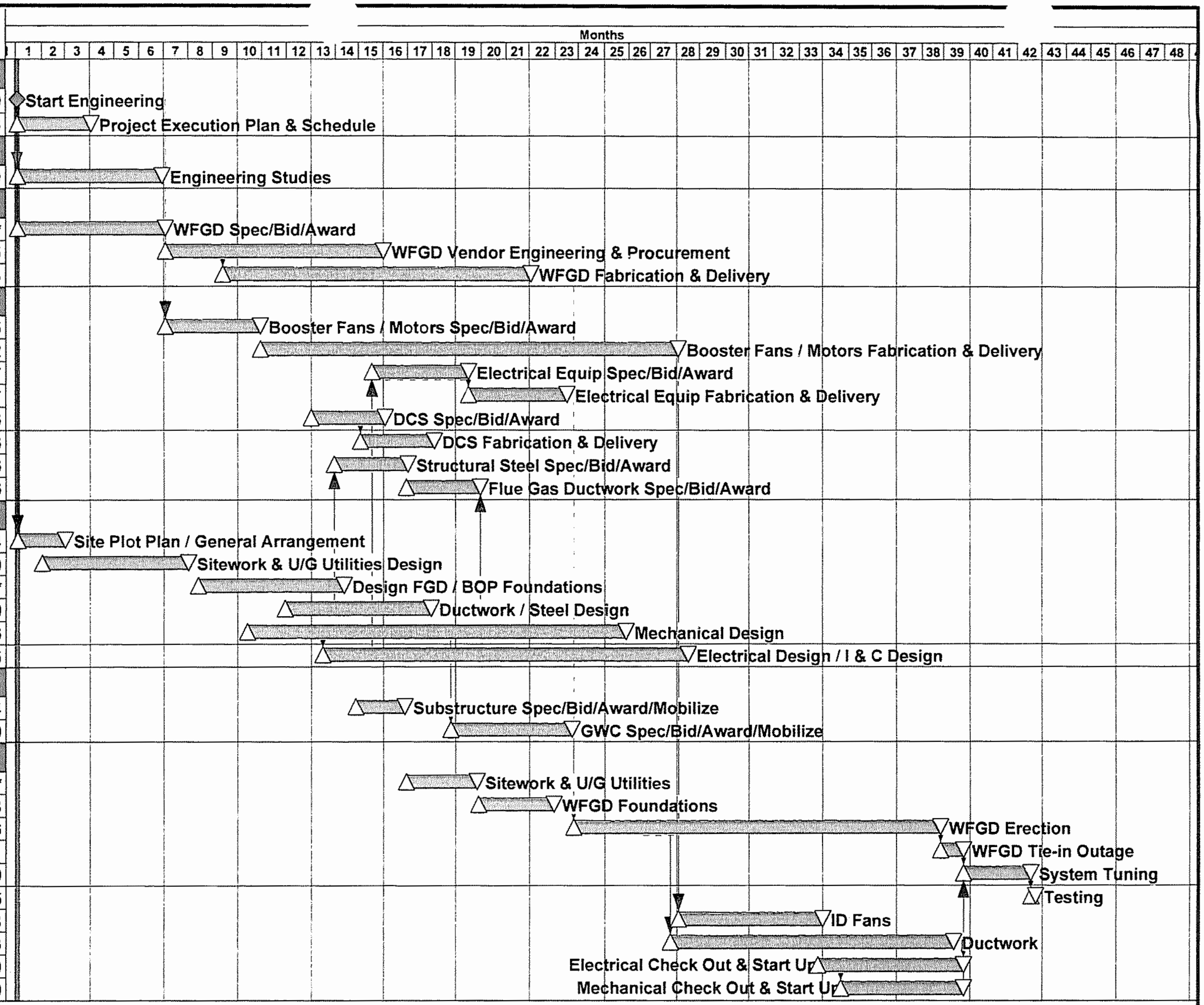
*Note O&M savings associated with reduced maintenance and operational labor/parts have been extimated based on S&L expience due to lack of available operational data.

**Note SO2 emissions in this scenario have been adjusted to reflect recent data received from BREC confirming that the Coleman FGD is capable of producing emission rates of 0.25lb/MMBtu and reaching removal rates of approximately 95%.

***Note four (4) HCl monitors are required for Coleman. One (1) for the common WFGD stack and one (1) for each unit bypass stack.

Appendix 2 – Level 1 Project Schedules

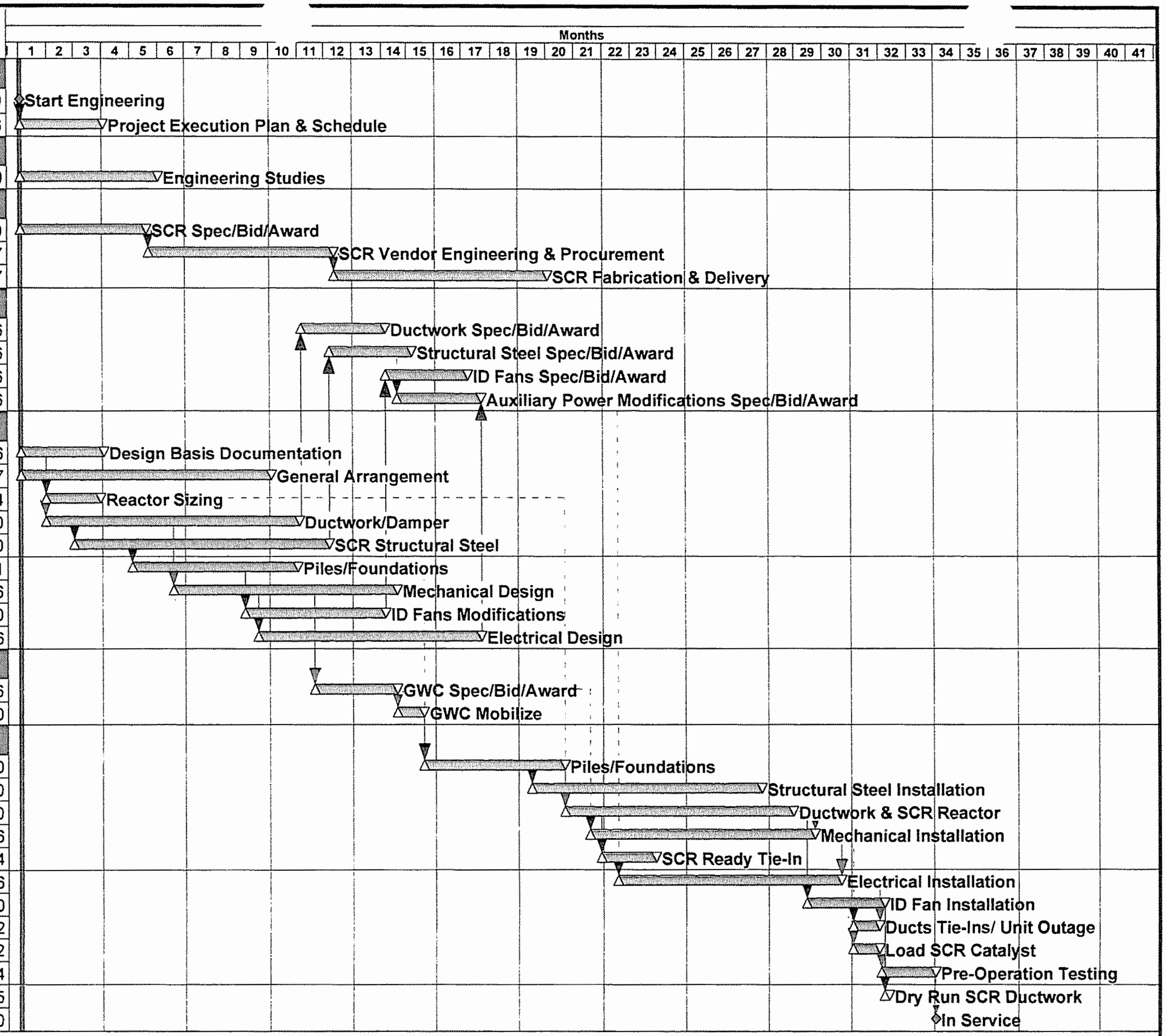
Act ID	Activity Description	Orig Dur
Administration		
1010	Start Engineering	0
1015	Project Execution Plan & Schedule	66
Engineering Studies		
1050	Engineering Studies	130
Process Procurement		
1200	WFGD Spec/Bid/Award	131*
1240	WFGD Vendor Engineering & Procurement	195
1250	WFGD Fabrication & Delivery	273
BOP Procurement		
1590	Booster Fans / Motors Spec/Bid/Award	85
1602	Booster Fans / Motors Fabrication & Delivery	372
1610	Electrical Equip Spec/Bid/Award	87
1620	Electrical Equip Fabrication & Delivery	87
1621	DCS Spec/Bid/Award	66
1630	DCS Fabrication & Delivery	66
1640	Structural Steel Spec/Bid/Award	66
1650	Flue Gas Ductwork Spec/Bid/Award	66
BOP Engineering		
1150	Site Plot Plan / General Arrangement	44
1720	Sitework & U/G Utilities Design	130
1732	Design FGD / BOP Foundations	130*
1750	Ductwork / Steel Design	130
1760	Mechanical Design	336
1770	Electrical Design / I & C Design	325
Installation Contracts		
22100	Substructure Spec/Bid/Award/Mobilize	44
22110	GWC Spec/Bid/Award/Mobilize	110
Construction / Start Up		
1695	Sitework & U/G Utilities	65*
2050	WFGD Foundations	68
2060	WFGD Erection	326
2070	WFGD Tie-in Outage	21
2080	System Tuning	60
2090	Testing	5
2140	ID Fans	128
2200	Ductwork	253
2400	Electrical Check Out & Start Up	130
2402	Mechanical Check Out & Start Up	110



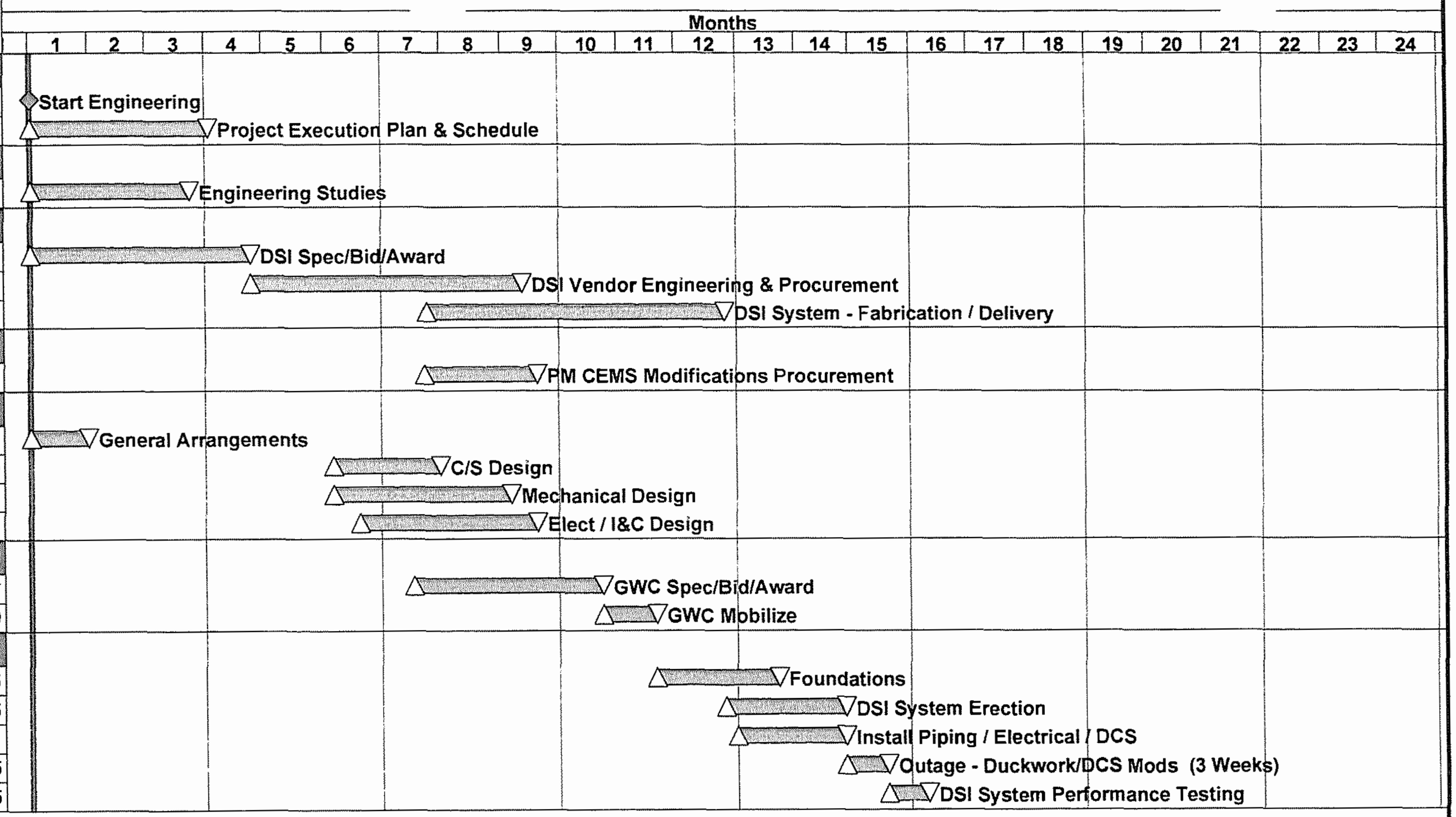
Run Date	03NOV11 14:55	WFGD	**Big Rivers** **Wet FGD** **Level I Study Schedule**	Sheet 1 of 1

Sargent & Lundy LLC

Activity ID	Activity Description	Orig Dur
Administration		
100	Start Engineering	0
110	Project Execution Plan & Schedule	66
Engineering Studies		
150	Engineering Studies	110
Process Procurement		
235	SCR Spec/Bid/Award	100
245	SCR Vendor Engineering & Procurement	147
248	SCR Fabrication & Delivery	167
BOP Procurement		
250	Ductwork Spec/Bid/Award	66
240	Structural Steel Spec/Bid/Award	66
280	ID Fans Spec/Bid/Award	66
260	Auxiliary Power Modifications Spec/Bid/Award	66
BOP Engineering		
300	Design Basis Documentation	66
310	General Arrangement	197
340	Reactor Sizing	44
320	Ductwork/Damper	200
330	SCR Structural Steel	200
350	Piles/Foundations	131
360	Mechanical Design	176
370	ID Fans Modifications	110
380	Electrical Design	176
Installation Contracts		
270	GWC Spec/Bid/Award	66
290	GWC Mobilize	20
Construction / Start Up		
400	Piles/Foundations	110
410	Structural Steel Installation	180
420	Ductwork & SCR Reactor	180
430	Mechanical Installation	176
600	SCR Ready Tie-In	44
440	Electrical Installation	176
450	ID Fan Installation	60
610	Ducts Tie-Ins/ Unit Outage	22
620	Load SCR Catalyst	22
640	Pre-Operation Testing	44
630	Dry Run SCR Ductwork	5
650	In Service	0



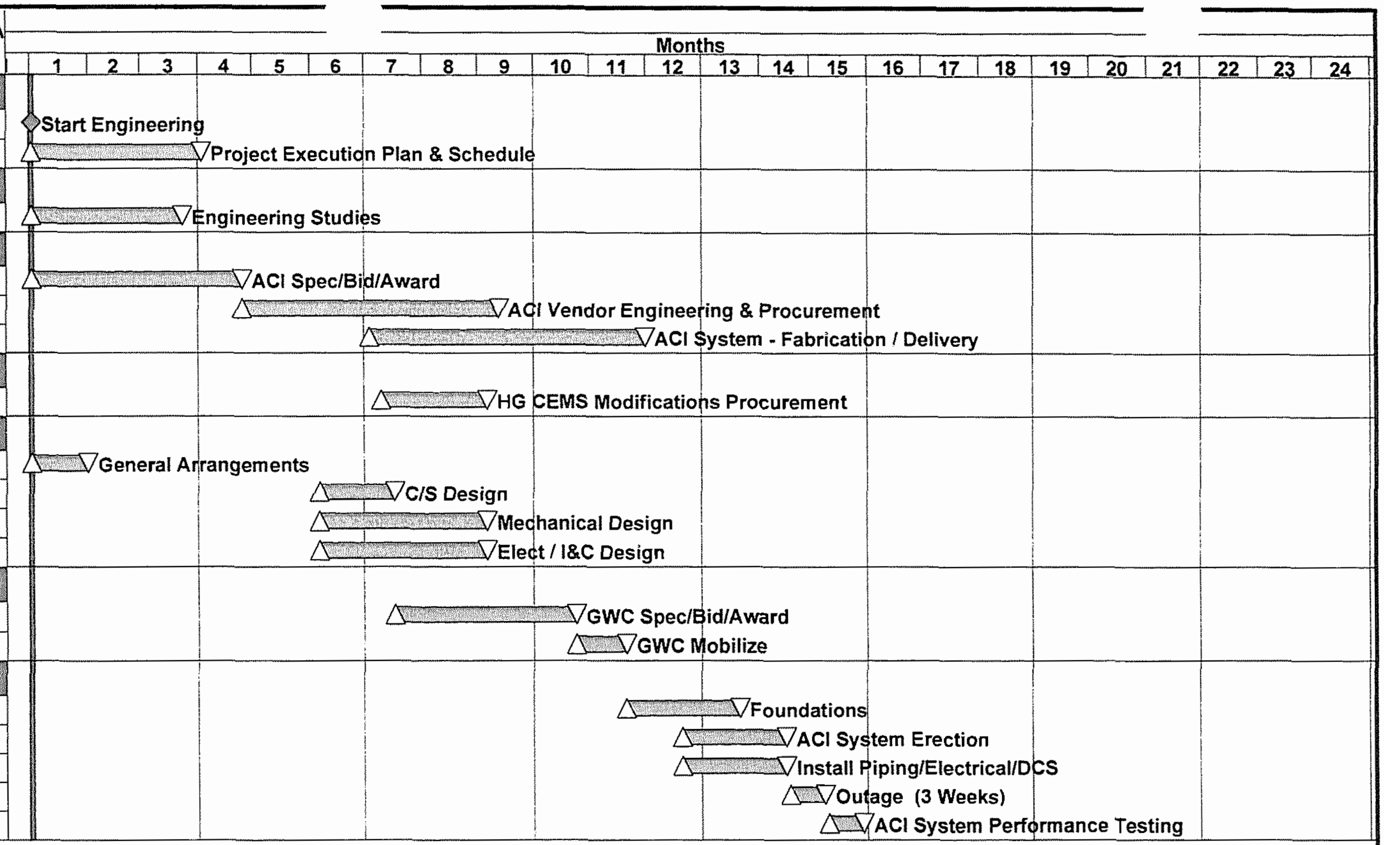
Activity ID	Activity Description	Orig Dur
Administration		
ADM1000	Start Engineering	0
ADM1100	Project Execution Plan & Schedule	66
Engineering Studies		
ENG1130	Engineering Studies	60
Process Procurement		
DSI1105	DSI Spec/Bid/Award	82*
DSI1250	DSI Vendor Engineering & Procurement	100
DSI1300	DSI System - Fabrication / Delivery	110
BOP Procurement		
PMC1000	PM CEMS Modifications Procurement	42
BOP Engineering		
DSI1050	General Arrangements	22
DSI1500	C/S Design	40
DSI1510	Mechanical Design	66
DSI1520	Elect / I&C Design	66
Installation Contracts		
GWC1480	GWC Spec/Bid/Award	70*
GWC1485	GWC Mobilize	20
Construction / Start Up		
CS1000	Foundations	45
CS1100	DSI System Erection	45
CS1200	Install Piping / Electrical / DCS	41
CS1300	Outage - Duckwork/DCS Mods (3	15
CS1400	DSI System Performance Testing	15



Big Rivers
DSI
Level I Study Schedule

Sargent & Lundy LLC

Activity ID	Activity Description	Orig Dur	AREA
Administation			
ADM1000	Start Engineering	0	00
ADM1100	Project Execution Plan & Schedule	66	00
Engineering Studies			
ENG1820	Engineering Studies	60	12
Process Procurement			
ACI1100	ACI Spec/Bid/Award	82*	20
ACI1130	ACI Vendor Engineering & Procurement	100	20
ACI1140	ACI System - Fabrication / Delivery	108	20
BOP Procurement			
HGC1500	HG CEMS Modifications Procurement	42	50
BOP Engineering			
ACI1050	General Arrangements	22	55
ACI1900	C/S Design	30	55
ACI1950	Mechanical Design	66	55
ACI2000	Elect / I&C Design	66	55
Installation Contracts			
GWC1475	GWC Spec/Bid/Award	70*	70
GWC1485	GWC Mobilize	20	70
Construction / Start Up			
ACI1700	Foundations	44	80
ACI1750	ACI System Erection	41	80
ACI1760	Install Piping/Electrical/DCS	41	80
ACI1800	Outage (3 Weeks)	15	80
ACI1810	ACI System Performance Testing	15	80



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LBWU

Big Rivers
ACI
Level I Study Schedule

Sheet 1 of 1

Sargent & Lundy LLC

Appendix 3 – NPV Calculations

CSAPR & NAAQS Compliance Technology NPV & LRR Calculations

Polutant		SO2						
Credit Cost ($/ton)			SO_2=	$500	NOx=	$2,500		
Technology/Modification		Wilson FGD	HMP&L FGD Mods	Green 2 Natural Gas Conversion	Green 1&2 Natural Gas Conversion	Reid Natural Gas Conversion	CSAPR 2014 Strategy	NAAQS Strategy
Economic Parameters:								
Evaluation Period	Years	20	20	20	20	20	20	20
Discount rate	%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%
Capital Cost Escalation Rate	%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
O&M Escalation Rate	%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
Base Year		2011	2011	2011	2011	2011	2011	2011
Present value Year		2011	2011	2011	2011	2011	2011	2011
Installation year		2014	2014	2014	2014	2014	2014	2014
Levelized Fixed Charge Rate		10.13%	10.13%	10.13%	10.13%	10.13%	10.13%	10.13%
Annuity Factor		0.1013	0.1013	0.1013	0.1013	0.1013	0.1013	0.1013
PV factor for Capital		0.8563	0.8563	0.8563	0.8563	0.8563	0.8563	0.8563
PV factor for O&M		10.4101	10.4101	10.4101	10.4101	10.4101	10.4101	10.4101
Capital Cost	$	139,000,000	6,300,000	25,600,000	55,100,000	1,200,000	146,500,000	146,500,000
Total O&M	$/yr	690,000	760,000	46,640,000	93,830,000	3,840,000	5,290,000	5,290,000
Total O&M (Including Credits)	$/yr	-3,504,644	-914,606	43,427,542	87,645,405	757,452	-3,661,798	-3,661,798
SO_2 Removed per year	tons/yr	8,389	3,349	1,411	3,281	5,065	16,804	16,804
	$/yr	$4,194,644	$1,674,606	$705,406	$1,640,565	$2,532,548	$8,401,798	$8,401,798
NO_X Removed per year	tons/yr	0	0	1,003	1,818	220	220	220
	$/yr	$0	$0	$2,507,053	$4,544,030	$550,000	$550,000	$550,000
Net Present Value (w/o Credits)	$	126,215,000	13,307,000	507,448,000	1,023,961,000	41,002,000	180,524,000	180,524,000
Net Present Value	$	82,549,000	-4,126,000	474,006,000	959,579,000	8,913,000	87,335,000	87,335,000
Break Even Credit Cost		$1,445	$382	$32,775	$28,593	$669	$1,090	$1,090
Levelized Revenue Requirement	$/yr	$8,364,048	-$418,055	$48,027,342	$97,226,678	$903,085	$8,848,976	$8,848,976
$/ton @ baseline credit value		$997	($125)	$19,898	$19,069	$171	$615	$615

Polutant		NOx												
Credit Cost ($/ton)						SO_2=	$500		NOx=	$2,500				
Technology/Modification		C1 SNCR	C2/3 SNCR	Green 1 SCR	Green 2 SCR	Green 1&2 SCR	Green 2 Natural Gas Conversion	Green 1&2 Natural Gas Conversion	Reid Natural Gas Conversion	Coleman 1,2&3 Advanced Burners	Green 1&2 SNCR	CSAPR 2014 Strategy	NAAQS Strategy
Economic Parameters:													
Evaluation Period	Years	20	20	20	20	20	20	20	20	20	20	20	20
Discount rate	%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%
Capital Cost Escalation Rate	%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
O&M Escalation Rate	%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
Base Year		2011	2011	2011	2011	2011	2011	2011	2011	2011	2011	2011	2011
Present value Year		2011	2011	2011	2011	2011	2011	2011	2011	2011	2011	2011	2011
Installation year		2014	2014	2014	2014	2014	2014	2014	2014	2014	2014	2014	2014
Levelized Fixed Charge Rate		10.13%	10.13%	10.13%	10.13%	10.13%	10.13%	10.13%	10.13%	10.13%	10.13%	10.13%	10.13%
Annuity Factor		0.1013	0.1013	0.1013	0.1013	0.1013	0.1013	0.1013	0.1013	0.1013	0.1013	0.1013	0.1013
PV factor for Capital		0.8563	0.8563	0.8563	0.8563	0.8563	0.8563	0.8563	0.8563	0.8563	0.8563	0.8563	0.8563
PV factor for O&M		10.4101	10.4101	10.4101	10.4101	10.4101	10.4101	10.4101	10.4101	10.4101	10.4101	10.4101	10.4101
Capital Cost	$	2,400,000	5,400,000	81,000,000	81,000,000	162,000,000	25,600,000	55,100,000	1,200,000	17,820,000	7,000,000	98,820,000	181,020,000
Total O&M	$/yr	1,560,000	3,160,000	2,160,000	2,160,000	4,320,000	46,640,000	93,830,000	3,840,000	0	3,220,000	6,000,000	8,160,000
Total O&M (Including Credits)	$/yr	630,905	1,345,262	-2,196,146	-2,446,790	-4,642,936	43,427,542	87,645,405	757,452	-1,372,500	1,111,074	-3,061,255	-5,257,401
SO_2 Removed per year	tons/yr	0	0	0	0	0	1,411	3,281	5,065	0	0	5,065	5,065
	$/yr	$0	$0	$0	$0	$0	$705,406	$1,640,565	$2,532,548	$0	$0	$2,532,548	$2,532,548
NO_X Removed per year	tons/yr	372	726	1,742	1,843	3,585	1,003	1,818	220	549	844	2,611	4,354
	$/yr	$929,095	$1,814,739	$4,356,146	$4,606,790	$8,962,936	$2,507,053	$4,544,030	$550,000	$1,372,500	$2,108,926	$6,528,706	$10,884,852
Net Present Value (w/o Credits)	$	18,295,000	37,520,000	91,850,000	91,850,000	183,700,000	507,448,000	1,023,961,000	41,002,000	15,260,000	39,515,000	147,085,000	239,962,000
Net Present Value	$	8,623,000	18,629,000	46,502,000	43,893,000	90,395,000	474,006,000	959,579,000	8,913,000	972,000	17,561,000	52,756,000	100,286,000
Break Even Credit Cost		$4,729	$4,965	$5,064	$4,788	$5,162	$47,905	$53,214	$6,392	$2,670	$4,500	$4,197	$4,795
Levelized Revenue Requirement	$/yr	$873,702	$1,887,532	$4,711,686	$4,447,336	$9,159,022	$48,027,342	$97,226,678	$903,085	$98,485	$1,779,320	$5,345,355	$10,161,201
$/ton @ baseline credit value		$2,351	$2,600	$2,704	$2,413	$2,555	$19,898	$19,069	$171	$179	$2,109	$1,055	$2,006

Big Rivers Electric Corporation

CCR & 316(b) Compliance Technology NPV & LRR Calculations

Environmental Compliance Study
2/13/2012

Station		Coleman						Sebree			HMP&L			Green			Wilson
Technology/Modification:		WIP Screens	Fish Retun Buckets	Wedgewire	Remote SSC	Dewatering Bin	Vacuum Conversion	WIP Screens	Fish Retun Buckets	Wedgewire	Remote SSC	Dewatering Bin	Vacuum Conversion	Remote SSC	Dewatering Bin	Vacuum Conversion	Vacuum Conversion
Economic Parameters:																	
Evaluation Period	Years	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Discount rate	%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%
Capital Cost Escalation Rate	%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
O&M Escalation Rate	%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
Base Year		2011	2011	2011	2011	2011	2011	2011	2011	2011	2011	2011	2011	2011	2011	2011	2011
Present value Year		2011	2011	2011	2011	2011	2011	2011	2011	2011	2011	2011	2011	2011	2011	2011	2011
Installation year		2014	2014	2014	2014	2014	2014	2014	2014	2014	2014	2014	2014	2014	2014	2014	2014
Levelized Fixed Charge Rate		10.13%	10.13%	10.13%	10.13%	10.13%	10.13%	10.13%	10.13%	10.13%	10.13%	10.13%	10.13%	10.13%	10.13%	10.13%	10.13%
Annuity Factor		0.1013	0.1013	0.1013	0.1013	0.1013	0.1013	0.1013	0.1013	0.1013	0.1013	0.1013	0.1013	0.1013	0.1013	0.1013	0.1013
PV factor for Capital		0.8563	0.8563	0.8563	0.8563	0.8563	0.8563	0.8563	0.8563	0.8563	0.8563	0.8563	0.8563	0.8563	0.8563	0.8563	0.8563
PV factor for O&M		10.4101	10.4101	10.4101	10.4101	10.4101	10.4101	10.4101	10.4101	10.4101	10.4101	10.4101	10.4101	10.4101	10.4101	10.4101	10.4101
Capital Cost	$	3,975,000	5,610,000	6,450,000	38,000,000	48,000,000	10,000,000	2,050,000	2,800,000	2,450,000	28,000,000	38,000,000	6,000,000	28,000,000	38,000,000	6,000,000	5,000,000
O&M	$/yr	750,000	750,000	810,000	1,250,000	860,000	0	365,000	365,000	380,000	970,000	680,000	0	1,250,000	870,000	0	0
Fuel Cost	$/yr																
Total O&M	$/yr	750,000	750,000	810,000	1,250,000	860,000	0	365,000	365,000	380,000	970,000	680,000	0	1,250,000	870,000	0	0
SO_2 Removed per year	tons/yr																
	$/yr																
NO_X Removed per year	tons/yr																
	$/yr																
Net Present Value	$	11,212,000	12,612,000	13,956,000	45,554,000	50,057,000	8,563,000	5,555,000	6,197,000	6,054,000	34,075,000	39,620,000	5,138,000	36,990,000	41,598,000	5,138,000	4,282,000

MACT Compliance Technology NPV & LRR Calculations

Polutant		Hg			TPM			
Technology/Modification		Coleman ACI	WIlson ACI	Green ACI	Coleman DSI and ESP Upgrades	Wilson Low Oxidation Catalyst & ESP Upgrades	Green DSI & ESP Upgrades	HMP&L DSI, Low Oxidation Catalyst and ESP Upgrades
Economic Parameters:								
Evaluation Period	Years	20	20	20	20	20	20	20
Discount rate	%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%
Capital Cost Escalation Rate	%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
O&M Escalation Rate	%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
Base Year		2011	2011	2011	2011	2011	2011	2011
Present value Year		2011	2011	2011	2011	2011	2011	2011
Installation year		2014	2014	2014	2014	2014	2014	2014
Levelized Fixed Charge Rate		**10.13%**	**10.13%**	**10.13%**	**10.13%**	**10.13%**	**10.13%**	**10.13%**
Annuity Factor		0.1013	0.1013	0.1013	0.1013	0.1013	0.1013	0.1013
PV factor for Capital		0.8563	0.8563	0.8563	0.8563	0.8563	0.8563	0.8563
PV factor for O&M		10.4101	10.4101	10.4101	10.4101	10.4101	10.4101	10.4101
Capital Cost	**$**	**4,000,000**	**4,500,000**	**4,000,000**	**7,720,000**	**11,040,000**	**8,340,000**	**8,500,000**
O&M (Including Fuel)	**$/yr**	**810,000**	**2,190,000**	**1,140,000**	**352,667**	**170,000**	**391,000**	**374,000**
Total O&M	**$/yr**	**810,000**	**2,190,000**	**1,140,000**	**352,667**	**170,000**	**391,000**	**374,000**
Net Present Value	**$**	**11,858,000**	**26,652,000**	**15,293,000**	**10,282,000**	**11,224,000**	**11,212,000**	**11,172,000**

Appendix 4 – Phase I Environmental Regulatory Review

Big Rivers Electric Corporation

Environmental Regulatory Impact Evaluation

FINAL

Prepared by:
Sargent & Lundy LLC
Chicago, Illinois

Sargent & Lundy LLC

October 17, 2011

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Executive Summary

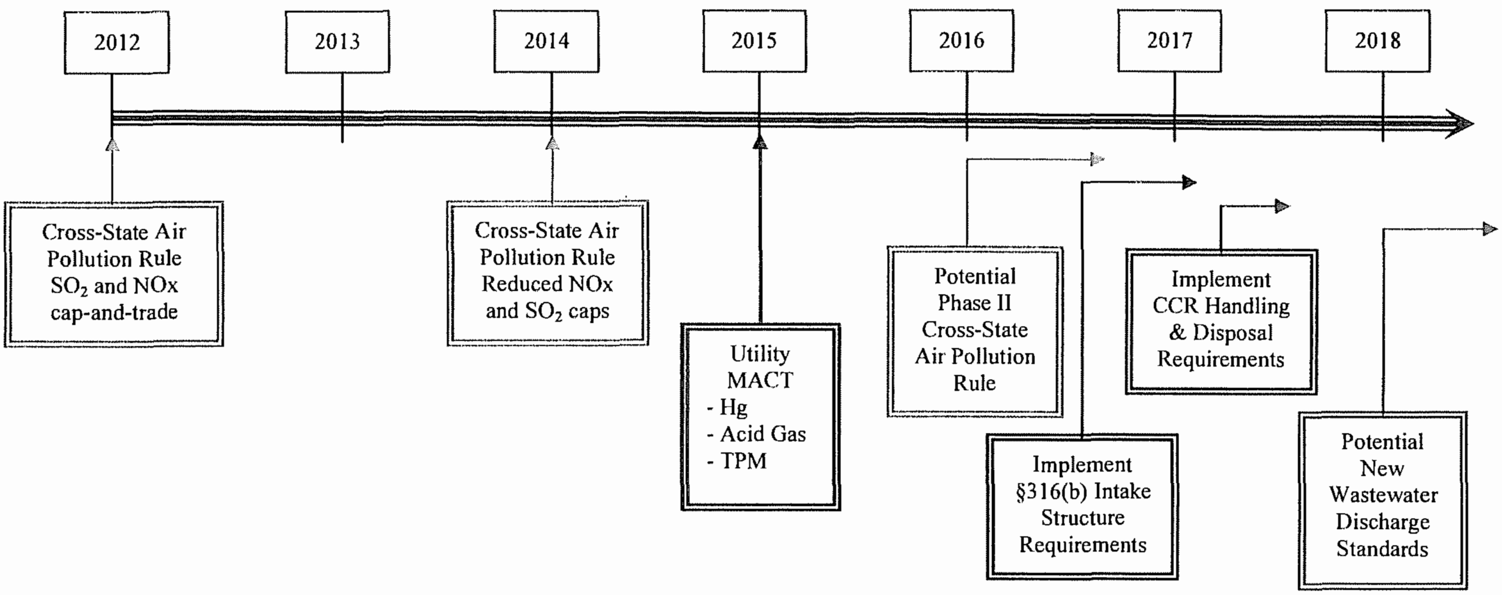
The U.S. Environmental Protection Agency (EPA) and the U.S. Congress have been actively developing environmental regulations and legislation that may impact coal and oil-fired power plant operations. Future regulations are expected to require additional reductions of the criteria air pollutants including sulfur dioxide (SO_2), nitrogen oxides (NOx), and particulate matter (PM, including PM_{10} and $PM_{2.5}$), and will likely compel additional control of other air pollutants including mercury, acid gases, trace metals, and potentially carbon dioxide (CO_2).

This report provides a detailed summary of the recently issued, proposed and pending environmental regulations and legislation, as well as an evaluation of the potential impacts these initiatives may have on operations at the Big River Electric Corporation's ("BREC's") Kenneth C. Coleman, D.B. Wilson, and Sebree generating stations. Regulatory and legislative initiatives evaluated in this report include:

- Clean Air Interstate Rule (CAIR)
- Cross-State Air Pollution Rule (CSAPR) - (the CAIR Replacement Rule)
- Emission Standards for Hazardous Air Pollutants (Utility MACT)
- Regional Haze Rule
- New and Proposed Revisions to the National Ambient Air Quality Standards (NAAQS)
- Phase II Cross-State Air Pollution Rule
- Multi-Pollutant and Greenhouse Gas Legislation
- Greenhouse Gas Tailoring Rule
- 316(b) Cooling Water Intake Regulations
- Coal Combustion Residue Regulations
- Wastewater Discharge Standards for the Steam Electric Power Point Source Category

Figure ES-1 provides a timeline showing the anticipated promulgation and implementation of the various environmental regulatory initiatives currently being considered by EPA.

Figure ES-1
Environmental Regulatory Implementation Timeline



Although several environmental initiatives are currently being advanced by EPA, the regulatory initiatives that could have the most immediate impact on the BREC generating units are the Cross-State Air Pollution Rule (CSAPR) and the proposed Utility MACT Rule. Table ES-1 provides a high-level summary of the emission reductions needed to meet BREC's CSAPR emission allowance allocations and the anticipated Utility MACT emission limits.

Table ES-1
BREC Required Emission Reduction by TPY/Percentage

	Cross-State Air Pollution Rule(1)						Utility MACT(2)	
	2012			2014			2015	
Plant	**SO2**	**Annual NOx**	**Ozone Season NOx**	**SO2**	**Annual NOx**	**Ozone Season NOx**	**TPM**	**Hg**
Coleman Unit C01	1,199	(930)	(331)	(323)	(1,017)	(377)	25%	66%
Coleman Unit C02	1,200	(657)	(328)	(323)	(743)	(375)	25%	66%
Coleman Unit C03	1,279	(1,054)	(418)	(345)	(1,146)	(468)	25%	66%
Wilson Unit W01	(1,038)	1,984	955	(5,824)	1,711	802	None	32%
Green Unit G01	205	(465)	(93)	91	(613)	(173)	None	61%
Green Unit G02	357	(565)	(188)	357	(715)	(268)	None	53%
HMP&L Unit H01	291	550	239	(976)	456	188	6%	None
HMP&L Unit H02	252	623	285	(1,456)	526	232	7%	None
Reid Unit R01	(4,558)	(336)	(116)	(4,847)	(352)	(125)	>90%	82%
Reid Unit RT	6	(38)	(28)	4	(39)	(29)	None	None
Fleet Total	**(808)**	**(888)**	**(23)**	**(13,643)**	**(1,932)**	**(593)**	**N/A**	**N/A**
Reduction Needed	**3%**	**7%**	**0.5%**	**50%**	**16%**	**12%**	**N/A**	**N/A**

(1) The CSAPR summary shows each units projected allowance surplus (Green) or deficit (Purple). Allowance surplus or deficits were calculated by subtracting each units' baseline emissions from its CSAPR allowances.

(2) The Utility MACT summary shows the emission reduction requirement (as a percent of baseline emissions) that each unit will need to achieve to meet the proposed Utility MACT Total Particulate Matter (TPM) and mercury (Hg) emission limits.

CSAPR will replace CAIR in 2012, and is intended to implement the Clean Air Act requirements concerning the transport of air pollutants across state boundaries, and assist downwind states to attain and maintain the Ozone and $PM_{2.5}$ NAAQS. The rule, published by EPA in the Federal Register on August 8, 2011 (76 Fed. Reg. 48208), includes an SO_2 cap-and-trade program, as well as annual and ozone season NOx cap-and-trade programs. BREC's Coleman, Wilson, and Sebree Generating Stations will be subject to the CSAPR NOx and SO_2 cap-and-trade programs beginning January 1, 2012.

Because CSAPR is a cap-and-trade program, compliance with the emission allowance requirements was evaluated on a systemwide basis. Table ES-2 provides a summary of the CSAPR emission allowances issued to each BREC unit. Table ES-3 shows the emission reductions, as a percent of baseline actual emissions, that BREC will need to achieve on a systemwide basis to match its CSAPR allowance allocations.

Table ES-2
BREC CSAPR SO_2 and NOx Allowance Allocations (2012 and 2014)

BREC Unit	Annual SO_2 Allowances (tpy)		Annual NOx Allowances (tpy)		Ozone Season NOx Allowances (tpy)	
	2012	2014	2012	2014	2012	2014
Coleman Unit C01	2,672	1,150	928	841	402	356
Coleman Unit C02	2,673	1,150	928	842	407	360
Coleman Unit C03	2,850	1,226	990	898	439	389
Wilson Unit W01	8,400	3,614	2,918	2,645	1,333	1,180
Green Unit G01	2,078	1,964	1,585	1,437	696	616
Green Unit G02	1,771	1,771	1,603	1,453	702	622
HMP&L Unit H01	2,518	1,251	1,010	916	447	396
HMP&L Unit H02	2,997	1,289	1,041	944	464	411
Reid Unit R01	508	219	176	160	77	68
Reid Unit RT	11	9	7	6	5	4
Total	26,478	13,643	11,186	10,142	4,972	4,402

Table ES-3
BREC CSAPR SO_2 and NOx Reduction Requirements (2012 and 2014)

Fleet-Wide Emission	Annual Allowances (tpy)		Baseline Annual Emission (tpy)	Required Reduction	
	2012	2014		2012	2014
SO_2	26,478	13,643	27,286	3%	50%
Annual NOx	11,186	10,142	12,074	7%	16%
Ozone Season NOx	4,972	4,402	4,995	0.5%	12%

Options for reducing systemwide SO_2 emissions to match the 2014 CSAPR SO_2 allowance allocations include upgrading, modifying, or replacing the existing FGD control systems on the Coleman, Wilson, Green and HMP&L units to provide more aggressive SO_2 removal, installing FGD control on Unit R01, and/or retiring Unit R01. Options for reducing systemwide NOx emissions to match the 2014 CSAPR NOx allocations include, if technically feasible, more aggressive NOx reductions on the SCR-controlled units, combustion control modifications, and post-combustion controls (e.g., SNCR or SCR) on the Coleman, Green, and Reid generating units.

EPA is considering revisions to the 8-hour ozone and PM2.5 NAAQS. Revisions to the NAAQS would likely increase the number of 8-hour ozone and $PM_{2.5}$ nonattainment areas in Kentucky and other downwind states, and may trigger more stringent SO_2 and NOx emission requirements in the 2018 timeframe. One regulatory approach that is being considered to address the revised NAAQS (and corresponding nonattainment areas) is to modify the Cross-State Air Pollution Rule. Modifications to CSAPR would likely include reductions in each States' emission budgets, and a corresponding reduction in the number of allowances allocated to each unit. Until EPA revises the NAAQS and updates its ambient air quality impact modeling, it is difficult to accurately predict the emission reductions that would be triggered by the NAAQS revisions; however, based on a review of the Cross-State Air Pollution Rule baseline contribution modeling, it is projected that Phase II CSAPR allocations would be approximately 20% below the Phase I 2014 allocations (summarized in Table ES-2).

Assuming an additional 20% reduction in CSAPR allowance allocations, BREC's CSAPR allowance allocations will fall to 10,914 SO_2, 8,114 annual NOx, and 3,522 seasonal NOx allowances in the 2018 timeframe. To meet these allowance allocations (without purchasing additional allowances) BREC will have to reduce systemwide SO_2 emissions approximately 60%, and NOx emissions approximately 33% below their respective baseline rates.

EPA also published a final 1-hour SO_2 NAAQS on June 2, 2010. Unlike other NAAQS implementation rules, the 1-hour SO_2 rule requires regulatory agencies to supplement ambient air quality monitoring data with refined dispersion modeling to identify the nonattainment areas. Preliminary ambient air quality impact modeling conducted by a number of existing generating stations suggests that SO_2 emissions from coal-fired power plants that are not equipped with FGD controls, and existing units with relatively short stacks, may have modeled exceedances of the 1-hour standard. Facility-specific modeling would be needed to determine if SO_2 emissions from the BREC facilities have the potential to cause or contribute to an exceedance of the 1-hour SO_2 NAAQS. Compliance with this standard could require BREC to upgrade, modify, or replace the existing FGD control systems on the Coleman, Wilson, Green and HMP&L units, and install FGD control on Unit R01 in the 2016-2018 timeframe.

On May 3, 2011, EPA published the proposed Utility MACT Rule (76 Fed. Reg. 24976). The rule regulates hazardous air pollutant (HAP) emissions from coal and oil-fired electricity generating units (EGUs). Proposed emission limits applicable to the BREC generating units, along with recent stack emission test data, are summarized in Table ES-4.

Table ES-4
Proposed MACT Emission Limits vs. Actual Stack Emission Data

Proposed MACT Emission Limits		Stack Emission Test Data*					
		Green 1	Green 2	HMP&L 1	HMP&L 2	Coleman	Wilson - Coal
a. Total particulate matter (TPM)	0.030 lb/MMBtu	0.0195	0.0169	0.0319	0.0324	0.0398	0.0196
OR							
Total non-Hg HAP metals	0.000040 lb/MMBtu	0.0000906	0.0000678	0.0000959	0.0001203	0.0000910	0.0000591
b. Hydrogen chloride (HCl)	0.0020 lb/MMBtu	0.000281	0.000334	0.001670	0.001370	0.000236	0.000074
OR							
Sulfur dioxide (SO_2)	0.20 lb/MMBtu	0.186	0.139	0.347	0.415	0.250	0.510
c. Mercury (Hg)	1.2 lb/TBtu	3.09E-06	2.58E-06	6.19E-07	4.66E-07	3.52E-06	1.77E-06

* All test data is in lb/MMBtu unless noted otherwise. Green cells indicate baseline emissions below the applicable MACT emission limit. Yellow cells indicated emissions below, but within approximately 15% of the proposed emission limit. Purple cells indicate baseline emissions above the applicable MACT emission limit.

Based on a review of HAP emissions data available for the BREC generating units, and taking into consideration emissions data available from similar sources in EPA's HAP emissions database, the following emission reductions will likely be needed to meet the Utility MACT emission requirements:

Mercury: Based on available emissions data:

- HMP&L Units 1 and 2 currently meet the proposed MACT standard with no additional mercury controls.
- Mercury emissions from Coleman Units 1, 2 and 3, and Green Units 1 and 2 (ESP+ FGD) must be reduced by 53% to 66% to meet the proposed MACT emission limit.
- Mercury emissions from Wilson 1 (ESP+FGD+SCR) must be reduced by 32% to meet the proposed MACT standard.
- Mercury emissions from Reid Unit R01 (ESP-only) must be reduced by approximately 80% to meet the proposed MACT standard.

Mercury control options capable of achieving the required removal efficiencies include FGD additives to minimize mercury re-emission in the FGD, fuel additives that promote mercury oxidation and mercury capture in the units' ESP/FGD control systems, and activated carbon injection control systems.

Acid Gases: EPA proposed to use hydrochloric acid (HCl) as an indicator of acid gas emissions from coal-fired boilers, and proposed an HCl emission limit of 0.002 lb/MMBtu (approximately 2.0 ppm). Existing coal-fired units equipped with an FGD control system can choose to demonstrate compliance with the acid gas requirement by demonstrating compliance with the HCl emission limits, or alternatively, with an EPA proposed SO_2 emission limit of 0.20 lb/MMBtu (30-day average) as a surrogate for acid gas emissions.

Current baseline SO_2 emissions from the Coleman, Wilson, and HMP&L units are above the proposed MACT SO_2 emission limit. FGD modifications and upgrades needed to reduce systemwide annual emissions below the CSAPR allowances would likely result in a controlled SO_2 emission rate of 0.20 lb/MMBtu (30-day average), which would allow BREC to choose to demonstrate compliance with the Utility MACT acid gas standard using SO_2 as a surrogate.

If it is not technically/economically feasible to meet the SO_2 emission limit, BREC can choose to demonstrate compliance with the proposed HCl emission limit. Based on a review of available HCl emissions data, BREC units equipped with FGD should be below the proposed HCl emission limit. BREC would be required to demonstrate continuous compliance with the HCl emission limit using an HCl CEMS or by implementing an on-going (i.e., bi-monthly) stack test program.

Acid gas emissions from Reid Unit R01 (ESP-only) are currently uncontrolled. SO_2 emissions from R01 are well in excess of the proposed MACT limit, and it is likely that HCl emissions are also above the MACT limit (although some removal would be expected in the fly ash and ESP). The technical/economic feasibility of acid gas control technologies on Unit R01 will be evaluated; however, it is unlikely Unit R01 could achieve compliance with the proposed limits without installing an FGD control technology or dry sorbent injection (DSI) control system.

Non-Hg Metal HAPs: EPA proposed a total PM (filterable + condensible "TPM") emission limit of 0.030 lb/MMBtu (30-day average) as MACT for the non-Hg trace metal HAPs. As an alternative to meeting the TPM limit, existing units have the option of meeting a total non-Hg metal emission limit of 4.0×10^{-5} lb/MMBtu, or complying with individual non-Hg metal emission limits. It is anticipated that most existing electric utility boilers will try to meet the proposed TPM emission limit. Based on available emissions data, total non-Hg metal and individual non-Hg metal emissions from all of the BREC units are above the proposed MACT limits. Furthermore, choosing the non-Hg metal compliance alternatives presents significant risk because of the lack of control technologies available for certain trace metals.

Based on a review of recent stack test data, current baseline TPM emissions from HMP&L, Coleman and Reid are above the proposed MACT limit. TPM emissions from Green and Wilson are below the proposed MACT limit. Bituminous-fired units equipped with SCR tend to generate more sulfuric acid mist and condensible particulate emissions. Technologies capable of reducing both filterable and condensible PM emissions will be evaluated to determine the feasibility of meeting the proposed MACT limit of 0.030 lb/MMBtu (30-day average). Technologies available to reduce filterable PM emissions include ESP modifications and upgrades.

Technologies available to reduce condensible PM emissions include dry sorbent injection coupled with an ESP or baghouse, and wet ESP.

In addition to air pollution control regulations, EPA is also working on rulemaking initiatives that would impact the management and disposal of coal combustion residues (CCR), and the design and operation of cooling water intake structures at existing power plants (the "316(b) Rule"). EPA is also considering revising the wastewater discharge standards for steam electric power generating stations. Although all of these regulatory initiatives are relatively early in the rulemaking process, these regulations could have a significant impact on operations at the BREC generating stations in the 2016-2020 timeframe.

1.0 Introduction

U.S.EPA has been actively developing environmental regulations and legislation that may impact coal-fired power plant operations and the air pollution control equipment selection process. Future regulations are expected to require additional reductions of criteria pollutants including sulfur dioxide (SO_2), nitrogen oxides (NOx), and particulate matter (PM, including PM_{10} and $PM_{2.5}$), and may compel existing units to control additional pollutants including acid gases, trace metals, and potentially carbon dioxide (CO_2). In addition, future regulatory initiatives will include more stringent requirements for cooling water intake structures, wastewater discharges, and disposal of coal combustion residues.

This report reviews the status of each regulatory initiative, provides a summary of requirements as they may affect Big Rivers Electric Corporation's Kenneth C. Coleman, D.B. Wilson, and Sebree generating stations, and identifies potential compliance options as they relate to the various regulatory initiatives. A summary table is provided at the end of each section that includes a brief description of the regulatory initiative, potential emission reduction requirements, and available compliance strategies.

2.0 Background

Big Rivers Electric Corporation (BREC) is a member-owned electric power and transmission cooperative headquartered in Henderson, Kentucky. The BREC electric power generating stations supply the wholesale power needs of the member cooperatives. The member cooperatives provide retail electric power to more than 111,000 homes, farms, businesses, and industries in portions of 22 western Kentucky counties.[1] BREC owns and operates 1,563 megawatts (MW) of generating capacity at four generating stations: Kenneth C. Coleman Station (485 MW), D.B. Wilson Station (440 MW), Robert D. Green (496 MW), and Robert A. Reid (142 MW). BREC has a total power capacity of 1,900 MW, including rights to Henderson Municipal Power and Light (HMP&L) Station Two and contracted capacity from Southeastern Power Administration. For air permitting purposes, the Kentucky Department of Environmental Protection Division of Air Quality (DAQ) has determined that the Reid/Henderson/Green stations are one source as defined in 401 KAR 50:020 (Permits). Collectively, these generating units are referred to as the Sebree Generating Station. A brief description of each generating station is provided below.

Kenneth C. Coleman Generating Station

The Coleman Generating Station is located near the town of Hawesville in Hancock County, Kentucky. The source is an electric power generating station consisting of three (3) pulverized coal-fired boilers. Coleman 1 and 2 are nominally rated at 160 MW with an input rating of 1,800 MMBtu/hr. Coleman 3 is a 165 MW unit with an input rating of 1,800 MMBtu/hr. All three units are dry bottom wall-fired boilers, equipped with low-NOx burners and an electrostatic precipitator (ESP). The units fire an Illinois Basin coal with a heating value in the range of 10,800 to 11,800 Btu/lb and a sulfur content of approximately 2.8 to 3.3% as their primary fuel. Flue gas from each boiler is directed through a common wet limestone flue gas desulfurization (WFGD) control system and exhausted through a common stack. Construction of Coleman 1 and 2 commenced in 1966. Construction of Coleman 3 commenced in 1968.

[1] See, http://www.bigrivers.com

D. B. Wilson Generating Station

The Wilson Generating Station is located near the town of Centertown in Ohio County, Kentucky. The source is an electric power generating station consisting of one (1) pulverized coal-fired boiler. Wilson is nominally rated at 440 MW with an input rating of 4,585 MMBtu/hr. The unit is a wall-fired boiler, and is equipped with low NOx burners, ESP, wet limestone FGD, selective catalytic reduction (SCR), and hydrated lime injection control systems. The unit fires an Illinois Basin coal with a heating value in the range of 11,300 to 12,300 Btu/lb and a sulfur content of approximately 2.8 to 3.3% as its primary fuel. Secondary fuel is petroleum coke, pelletized coal fines, and number two fuel oil is available for startup and stabilization. The source has taken a conditional limit when burning petroleum coke in order to preclude applicability of the 401 KAR 51:017 Prevention of Significant Deterioration (PSD) regulations, where emissions of SO_2 shall not exceed 12,023 tons during any twelve month period in which any amount of petroleum coke is burned. Construction of the unit commenced June 20, 1980.

Sebree Generating Station

The Sebree Generating Station encompasses the Robert D. Green Station, Robert A. Reid Station, and HMP&L Station Two. The station is located near the town of Sebree in Webster County, Kentucky.

Robert D. Green Generating Station:

The Green Generating Station is an electric power generating station consisting of two (2) pulverized coal-fired boilers. Green 1 and 2 are nominally rated at 252 MW and 244 MW, respectively, with an input rating of 2,569 MMBtu/hr. The units are Babcock & Wilcox wall-fired boilers, equipped with low NOx burners and coal reburn technology, ESP, and a wet lime FGD control system. Both units fire an Illinois Basin bituminous coal with a heating value in the range of 11,300 to 12,300 Btu/lb and a sulfur content of approximately 2.8 to 3.3% as their primary fuel and burn Petroleum Coke as a secondary fuel. Green 1 and 2 exhaust through separate stacks. Construction of the Green units commenced in 1976.

Henderson Municipal Power & Light (HMP&L) Generating Station Two

The HMP&L Generating Station Two is an electric power generating station consisting of two (2) pulverized coal-fired boilers. HMP&L Station 2 Units 1 and 2 are nominally rated at 165 MW and 172 MW respectively, with an input rating of 1,624 MMBtu/hr. HMP&L Station Two Units 1 and 2 are dry-bottom wall-fired boilers equipped with ESP and wet lime FGD control systems. Both units are equipped with 1st generation low-NOx burners and selective catalytic reduction (SCR) for NOx control. Both units fire an Illinois Basin bituminous coal with a heating value in the range of 11,800 to 12,300 Btu/lb and a sulfur content of approximately 2.8 to 3.3% as their primary fuel. Construction of HMP&L Station 2 commenced in 1970.

Robert A. Reid Generating Station

The Reid Generating Station is an electric power generating station consisting of one (1) pulverized coal-fired boiler and one combination gas/oil fired combustion turbine. Reid 1 is nominally rated at 72 MW, with a heat input of 911 MMBtu/hr. Reid 1 is a dry-bottom wall-fired boiler equipped with a multiclone and an ESP for particulate matter control. Reid 1 fires an

Illinois Basin bituminous coal with a heating value in the range of 11,800 to 12,300 Btu/lb and a sulfur content of approximately 2.8 to 3.3% as their primary fuel. Construction of Reid 1 commenced in 1963.

Reid also has a natural gas-fired simple cycle combustion turbine. The combustion turbine is designed to fire natural gas or No. 2 fuel oil, and has a rated capacity of 803 MMBtu/hr. Construction of Unit RT commenced in 1970.

A brief description of BREC generating units is provided in Tables 2-1a and 2-1b.

Table 2-1a
Coleman and Wilson Generating Stations

Parameter	Coleman Unit C01		Coleman Unit CO2		Coleman Unit CO3		Wilson Unit W01	
Gross Unit Output (MW)	160		160		165		440	
Full Load Heat Input (MMBtu/hr)	1,800		1,800		1,800		4,585	
Primary Fuel	Illinois Basin bituminous		Illinois Basin bituminous		Illinois Basin bituminous		Illinois Basin bituminous	
Secondary Fuel	N/A		N/A		N/A		Pet Coke Pelletized Fines #2 Fuel Oil	
Unit Description	dry bottom wall-fired boiler		dry bottom wall-fired boiler		dry bottom wall-fired boiler		dry bottom wall-fired boiler	
NOx Control	LNB & ROFA		LNB & OFA		LNB & OFA		LNB/OFA/SCR	
PM Control	ESP		ESP		ESP		ESP	
SO_2 Control	Wet Limestone FGD		Wet Limestone FGD		Wet Limestone FGD		Wet Limestone FGD	
Condenser Cooling System	once-through cooling		once-through cooling		once-through cooling		closed cycle cooling	
Baseline Average Annual Heat Input(1)	11,784,789		11,787,242		12,570,106		37,043,481	
2010 Annual Heat Input	11,254,853		9,544,382		12,195,952		36,221,670	
Baseline Annual SO2 Emissions(1)	1,473	0.25	1,473	0.25	1,571	0.25	9,438	0.51
Annual NOx Emissions (2010)(2)	1,858	0.33	1,585	0.33	2,044	0.34	934	0.053
Ozone Season NOx Emissions (2010)(2)	733	0.33	735	0.34	857	0.34	378	0.050

(1) Baseline average annual heat inputs provided in this table represent the average of the three highest heat input years during the baseline years 2006-2010. Baseline annual SO_2 emissions represent the average of the three highest emission years (2006 – 2010); however, baseline SO_2 emissions from Coleman Units C01, C02, and C03 were adjusted to an annual average emission rate of 0.25 lb/MMBtu based on information provided by BREC.
(2) Baseline NOx emission rates are calculated using 2010 NOx emissions and 2010 heat inputs.

Table 2-1b
Sebree Generating Station

Parameter	Green Unit G01		Green Unit G02		Henderson Unit H01		Henderson Unit H02		Reid Unit R01		Reid Unit RT	
Gross Unit Output (MW)	252		244		172		165		72		70	
Full Load Heat Input (MMBtu/hr)	2,569		2,569		1,624		1,624		911		803	
Primary Fuel	Illinois basin bituminous		Illinois basin bituminous		Illinois basin bituminous		Illinois basin bituminous		Illinois basin bituminous		natural gas	
Secondary Fuel	Pet Coke		Pet Coke		N/A		N/A		N/A		Oil	
Unit Description	dry bottom wall-fired boiler		dry bottom wall-fired boiler		dry bottom wall-fired boiler		dry bottom wall-fired boiler		dry bottom wall-fired boiler		Combustion Turbine	
NOx Control	LNB		LNB		LNB/SCR		LNB/SCR		LNB			
PM Control	ESP		ESP		ESP		ESP		Cyclone ESP			
SO_2 Control	Wet Lime FGD		Wet Lime FGD		Wet Lime FGD		Wet Lime FGD					
Condenser Cooling System	closed cycle cooling		closed cycle cooling		closed cycle cooling		closed cycle cooling		once-through cooling			
Baseline Average Annual Heat Input(1)	20,128,359		20,347,531		12,823,005		13,214,893		2,240,807		87,379	
2010 Annual Heat Input	19,866,020		20,128,970		13,003,466		12,118,692		1,962,424		126,361	
Baseline Annual SO2 Emissions(1)	1,873	0.19	1,414	0.14	2,227	0.35	2,745	0.42	5,066	4.52	5	0.12
Annual NOx Emissions (2010) (2)	2,050	0.21	2,168	0.22	460	0.071	418	0.069	512	0.52	45	0.71
Ozone Season NOx Emissions (2010) (2)	789	0.20	890	0.21	208	0.074	179	0.066	193	0.47	33	0.70

(1) Baseline annual heat inputs, and baseline annual SO_2 emissions shown in this table represent that average of the three highest emission or heat input years during the years 2006 – 2010.
(2) Baseline NOx emission rates are calculated using 2010 NOx emissions and 2010 heat inputs.

3.0 Air Pollution Control Regulations

This section includes a description of the regulatory initiatives that may affect operations at the BREC generating stations. Each subsection includes a brief description of the regulation or initiative, describes the potential emission limits and control technology requirements, and identifies potential compliance strategies. In addition to the regulatory requirements discussed below, modifications to an existing emissions source can trigger applicability of the federal New Source Performance Standards (NSPS) and the New Source Review (NSR) pre-construction permitting requirements.

3.1 Clean Air Interstate Rule

EPA issued the Clean Air Interstate Rule (CAIR) on March 10, 2005. CAIR requires 28 eastern states (including Kentucky) and the District of Columbia to reduce emissions of SO_2 and NOx because those states contribute to fine particulate matter ($PM_{2.5}$) and ground level ozone non-attainment in downwind states. Under CAIR, states were required to reduce emissions of SO_2 and NOx in two phases: (1) the first phase of NOx and SO_2 reductions started in 2009 and 2010, respectively, and (2) the second phase of NOx and SO_2 reductions was scheduled to start in 2015. CAIR allows states to demonstrate compliance with the SO_2 and NOx reduction requirements by establishing a cap-and-trade program for SO_2 and NOx emissions.

On July 11, 2008, the U.S. Court of Appeals for the District of Columbia found that CAIR was "fundamentally flawed" and issued an order to vacate the rule in its entirety and remand the rule to EPA to promulgate a new rule consistent with the Court's opinion. Subsequently, EPA requested that the Court reinstate CAIR until it could issue a replacement rule. On December 23, 2008, the Court granted EPA's petition to remand the case without vacatur. As a result, CAIR went into effect in its entirety on January 1, 2009, and will remain in effect until EPA publishes the CAIR replacement rule addressing the flaws identified by the Court. EPA's CAIR replacement rule (the Cross-State Air Pollution Rule) was recently issued, and is discussed in detail in Section 3.2 of this report.

CAIR includes an annual SO_2 cap-and-trade program, an annual NOx cap-and-trade program, and an ozone season NOx cap-and-trade program. A brief description of the CAIR provisions, as they apply to the BREC generating stations, is provided below.

3.1.1 CAIR SO2 (Annual) Trading Program

The CAIR SO_2 annual trading program was designed to supplement the Title IV Acid Rain Program (ARP). The CAIR SO_2 annual trading program applies to fossil fuel-fired generating units located in 23 states, including Kentucky. The first phase of the CAIR SO_2 annual trading program took effect in 2010, and will now expire on January 1, 2012, when the CSAPR takes effect.

The CAIR SO_2 trading program uses the ARP SO_2 allowances, which will continue to be allocated to EGUs per the 1998 reallocation of allowances. CAIR reduces the net value of the ARP allowances for emissions in CAIR states as follows: allowances of vintage 2009 and earlier continue to be worth 1 ton of SO_2 (1:1), while allowances of vintages 2010 through 2014 are worth 0.5 ton SO_2 (0.5:1).

Table 3-1 shows the ARP allowance allocations for the BREC generating units. Table 3-2 compares the 2010 CAIR SO_2 allowance requirements (i.e., two allowances per ton of SO_2 emitted) to the average annual SO_2 emissions from each unit. Annual SO_2 emissions shown in Table 3-2 represent average annual emissions based on the three highest emission years between 2006 and 2010.

Table 3-1
Title IV Acid Rain Program SO_2 Allowance Allocations

BREC Unit	Acid Rain Allocations (tons per year)
Coleman Unit C01	4,853
Coleman Unit C02	5,534
Coleman Unit C03	5,322
Wilson Unit W01	12,461
Green Unit G01	5,292
Green Unit G02	6,376
HMP&L Unit H01	5,756
HMP&L Unit H02	5,934
Reid Unit R01	942
Total	52,470

Table 3-2
CAIR Phase I Allowance Requirements vs. Actual SO_2 Annual Emissions

BREC Unit	Baseline SO_2 Emissions[(1)] (tpy)	CAIR Phase I Allowance Requirements (2 x emissions)	Acid Rain Allocations (per year)	Allowance Surplus or (Deficit)
Coleman Unit C01	1,473	2,946	4,853	1,907
Coleman Unit C02	1,473	2,946	5,534	2,588
Coleman Unit C03	1,571	3,142	5,322	2,180
Wilson Unit W01	9,438	18,876	12,461	(6,415)
Green Unit G01	1,873	3,747	5,292	1,545
Green Unit G02	1,414	2,827	6,376	3,549
HMP&L Unit H01	2,227	4,454	5,756	1,302
HMP&L Unit H02	2,745	5,490	5,934	444
Reid Unit R01	5,066	10,132	942	(9,190)
Total	27,280	54,560	52,470	(2,090)

(1) Baseline SO_2 emissions for each unit shown in this table were calculated as the average annual emissions from the three highest emission years from each unit during the years 2006-2010. Baseline SO_2 emissions from Coleman Units C01, C02, and C03 were adjusted to an annual average emission rate of 0.25 lb/MMBtu based on information provided by BREC.

Emissions and allowance data summarized in Table 3-2, show that SO_2 emissions from the BREC generating units are very close to the CAIR Phase I allocation requirements. Annual SO_2 emissions from all units averaged between 25,575 tpy (actual average) and 27,280 tpy (average of three highest emission years) between 2006 and 2010. Therefore, BREC needs to retire between 51,150 and 54,560 CAIR Phase I SO_2 allowances annually, compared to its SO_2 allocation of 52,470 tons. Assuming annual capacity factors and average SO_2 emission rates remain relatively constant, BREC needs to reduce systemwide SO_2 emissions by zero to approximately 4% to match its CAIR Phase I SO_2 allocation requirements. Because CAIR is a cap-and-trade program, BREC could also use banked pre-2009 Acid Rain Program SO_2 allocations to offset any CAIR allowance deficiency.

Emissions from seven units (Coleman Units C01, C02, C03, Green Units G01, G02, and HMP&L Units H01 and H02) are below their respective CAIR SO_2 allocation requirements. These units are all equipped with wet lime or limestone FGD control systems.

Existing SO_2 emissions from Wilson Unit W01 and Reid Unit R01 are above their respective CAIR allocation requirements. Between 2006 and 2010 SO_2 emissions from Wilson Unit W01 averaged 9,438 tpy (or 18,876 CAIR Phase I SO_2 allocations), exceeding the unit's CAIR allocations of 12,461 tons. Assuming an annual heat input to the boiler of 37,043,481 MMBtu, SO_2 emissions from Wilson Unit W01 would need to be reduced by approximately 34%, from a baseline rate of 0.51 lb/MMBtu to a controlled rate of 0.33 lb/MMBtu, for the unit to match its allowance allocations.[2]

Similarly, SO_2 emissions from Reid Unit R01 currently exceed the unit's CAIR Phase I SO_2 allocation requirements. Between 2006 and 2010, SO_2 emissions from Reid Unit R01 averaged 5,066 tpy (or 10,132 CAIR Phase I SO_2 allocations),[3] exceeding the unit's CAIR allocations of 942 tons. Assuming an annual heat input of 2,240,807 MMBtu, SO_2 emissions from Reid Unit R01 would need to be reduced by approximately 91%, from a baseline rate of 4.61 lb/MMBtu to a controlled rate of 0.42 lb/MMBtu, for the unit to match its allowance requirements.

Although SO_2 emissions form the Wilson and Reid units exceed their CAIR allocations, CAIR is a cap-and-trade program; therefore, surplus allowances from the Coleman, Green, and HMP&L units can be used to offset excess SO_2 emissions from the Wilson and Reid units. On a systemwide basis, the annual SO_2 emissions from the BREC units are very close to, or slightly below, the CAIR allocation requirements.

3.1.2 CAIR NOx Trading Programs

In addition to the annual SO_2 cap-and-trade program, CAIR includes annual and ozone season NOx cap-and-trade programs. The CAIR annual NOx trading program was a new cap-and-trade program, while the CAIR ozone season NOx program largely replaced the NOx trading program established under the NOx SIP call. Both trading programs apply to electric generating units located in 25 of the 28 CAIR states (including Kentucky) and the District of Columbia. Phase I of the CAIR

[2] The baseline heat input represents that average annual heat input to Wilson Unit W01 during the three highest heat input years during the baseline years of 2006-2010.

[3] Note: SO2 emissions from Unit R01 in 2009 totaled only 545 tons. Total heat input to Unit R01 in 2009 was 236,191 MMBtu, about 10% of the average annual heat input during the other baseline years. Therefore, 2009 emissions data were not used to calculate average emissions from Unit R01.

NOx trading programs took effect in 2009. Phase II of the CAIR NOx trading programs was scheduled to take affect in 2015; however, Phase II of CAIR will be replaced by the Cross State Air Pollution Rule (CSAPR) (discussed in Section 3.2).

For CAIR Phase I, both the annual and seasonal NOx regional CAIR budgets were established by EPA using a regional heat-input baseline value multiplied by 0.15 lb/MMBtu. CAIR NOx allowances were allocated to each affected source based on each sources' proportional share of the state budget calculated using historical heat inputs and including a fuel adjustment factor for coal, oil, and natural gas. Table 3-3 provides a summary of the final Kentucky CAIR Phase I NOx budgets and the CAIR NOx allowance allocations to each BREC generating unit.

Table 3-3
CAIR Phase I NOx Allocations

BREC Unit	CAIR Phase I Annual NOx Allocations	CAIR Phase I Ozone Season NOx Allocations
Kentucky	83,205	36,045
Coleman Unit C01	898	375
Coleman Unit C02	902	383
Coleman Unit C03	879	379
Wilson Unit W01	3,210	1,359
Green Unit G01	1,573	653
Green Unit G02	1,551	660
HMP&L Unit H01	965	420
HMP&L Unit H02	993	420
Reid Unit R01	377	172
Reid Unit RT	3	3
BREC Total	11,351	4,824

Tables 3-4 and 3-5 compare the CAIR Phase I annual and ozone season NOx allocations to the 2010 actual NOx emissions from each unit.[4] NOx emission reductions needed to meet the CAIR Phase I NOx allowance requirements, if any, are also identified in Tables 3-4 and 3-5.

[4] NOx emissions data from 2010 were used in this regulatory evaluation because it was determined that 2010 emissions data were more representative of NOx emissions going forward.

Table 3-4
CAIR Phase I Annual NOx Allocations vs. 2010 Actual NOx Emissions

BREC Unit	CAIR Phase I Annual NOx Allocations (tons)	Annual NOx Emissions 2010(1) (tons)	Allowance Surplus or (Deficit)	Annual Heat Input 2010(1) (MMBtu)	Allowance Equivalent NOx Rate (lb/MMBtu)	Actual Average NOx Rate 2010 (lb/MMBtu)	% Reduction
Coleman Unit C01	898	1,858	(960)	11,254,853	0.160	0.330	51.5%
Coleman Unit C02	902	1,585	(683)	9,544,382	0.189	0.332	43.1%
Coleman Unit C03	879	2,044	(1,165)	12,195,952	0.144	0.335	57.0%
Wilson Unit W01	3,210	934	2,276	36,221,670	0.177	0.052	NA
Green Unit G01	1,573	2,050	(477)	19,866,020	0.158	0.206	23.3%
Green Unit G02	1,551	2,168	(617)	20,128,970	0.154	0.215	28.4%
HMP&L Unit H01	965	460	505	13,003,466	0.148	0.071	NA
HMP&L Unit H02	993	418	575	12,118,692	0.164	0.069	NA
Reid Unit R01	377	512	(135)	1,962,424	0.384	0.522	26.4%
Reid Unit RT	3	45	(42)	126,361	0.047	0.708	93.4%
Total	11,351	12,074	(723)	136,422,791	0.166	0.177	6.2%

(1) Annual NOx emissions and annual heat inputs listed in this table are based on actual 2010 emission and heat input values.

Table 3-5
CAIR Phase I Ozone Season NOx Allocations vs. 2010 Actual NOx Emissions

BREC Unit	CAIR Phase I Ozone Season NOx Allocations (tons)	Ozone Season NOx Emissions 2010(1) (tons)	Allowance Surplus or (Deficit)	Ozone Season Heat Input 2010(1) (MMBtu)	Allowance Equivalent NOx Rate (lb/MMBtu)	Average NOx Rate 2010 (lb/MMBtu)	% Reduction
Coleman Unit C01	375	733	(358)	4,413,566	0.170	0.332	48.8%
Coleman Unit C02	383	735	(352)	4,391,647	0.174	0.335	48.1%
Coleman Unit C03	379	857	(478)	5,084,415	0.149	0.337	55.8%
Wilson Unit W01	1,359	378	981	15,229,924	0.178	0.050	NA
Green Unit G01	653	789	(136)	7,820,468	0.167	0.202	17.3%
Green Unit G02	660	890	(230)	8,411,654	0.157	0.212	25.9%
HMP&L Unit H01	420	208	212	5,589,305	0.150	0.074	NA
HMP&L Unit H02	420	179	241	5,369,949	0.156	0.066	NA
Reid Unit R01	172	193	(21)	824,447	0.417	0.467	10.7%
Reid Unit RT	3	33	(30)	95,540	0.063	0.700	91.0%
Total	4,824	4,995	(171)	57,230,917	0.169	0.175	3.4%

(1) Ozone season NOx emissions and heat inputs listed in this table are based on actual 2010 emission and heat input values.

Emissions data summarized in Tables 3-4 and 3-5 show that existing NOx emissions from the BREC generating units are at, or just above, the Phase I CAIR NOx allocations. NOx emissions from three units (Wilson Unit W01 and HMP&L Units H01 and H02) are currently below their CAIR Phase I NOx allocations (both annual and ozone season). All three units are equipped with SCR control, and currently achieve controlled NOx emissions in the range of 0.052 to 0.070 lb/MMBtu.

NOx emissions from the other units, including Coleman Units C01, C02, and C03, Green Units G01 and G02, and Reid Unit R01, currently exceed their CAIR Phase I allocations. In 2010, NOx emissions from the Coleman Station totaled 5,487 tons, exceeding the Station's CAIR Phase I NOx allocations of 2,679 tons. NOx emissions from the Coleman generating units would need to be reduced by approximately 50%, from a base rate of 0.33 lb/MMBtu to a controlled rate of approximately 0.16 lb/MMBtu, for the station to match its allowance allocations. Similarly, 2010 NOx emissions from Green Units G01 and G02 exceeded the station's CAIR Phase I allocations by approximately 1,094 tons (4,218 tons emissions vs. 3,124 tons allocations). NOx emissions from the Green generating units would need to be reduced by approximately 25%, from a base rate of 0.21 lb/MMBtu to a controlled rate of approximately 0.16 lb/MMBtu, for the station to match its allowance allocations.

3.1.3 CAIR Phase I Summary

CAIR includes an annual SO_2 cap-and-trade program, an annual NOx cap-and-trade program, and an ozone season NOx cap-and-trade program. CAIR went into effect in its entirety on January 1, 2009, and will remain in effect until the recently published CSAPR takes effect on January 1, 2012.

Actual SO2 and NOx emissions from the BREC generating units are currently very close to the respective CAIR Phase I SO_2 and NOx allocation requirements. Annual SO_2 emissions from all units averaged 25,575 tpy (actual average) between 2006 and 2010 (or 51,150 CAIR SO_2 allowances) compared to an allocation of 52,470 allowances. Thus, based on average historical emissions, BREC should have adequate CAIR Phase I SO_2 allocations without providing additional SO_2 emission controls. If SO_2 emissions exceed the CAIR allocations in any individual year, banked CAIR allocations and banked pre-2009 Acid Rain Program SO_2 allocations, can be used to off-set any allocation deficit.

Systemwide annual and ozone season NOx emissions are also very close to (or slightly above) the CAIR Phase I NOx allocations. In 2010, annual NOx emissions from all units were approximately 6% above the CAIR Phase I allocation of 11,351 tons, and ozone season NOx emissions from all units were approximately 3.4% above the CAIR Phase I allocation of 4,824 tons. Relatively small NOx reductions on the non-SCR controlled units (e.g., C01, C02, C03, G01, and G02) could provide the emissions reductions needed for systemwide NOx emissions to match the CAIR Phase I NOx allocation requirements.

Table 3-6 provides a summary of CAIR Phase I allowance requirements and corresponding emission reduction requirements for each BREC generating unit.

Table 3-6
CAIR Phase I Summary

Pollutant	Station	Baseline Emissions emissions (allocations)	CAIR Phase I Allocations (tpy)	Emission Reductions Needed to Meet Allocations	Control Strategies
SO_2	Coleman	4,517 (9,034)	15,709	NA	Wet lime and limestone scrubbing control systems on Coleman Units C01, C02, and C03; Green Units G01 and G02; and HMP&L Units H01 and H02, currently reduce emissions below each unit's respective CAIR Phase I SO_2 allocation requirements. Existing SO_2 emissions from Wilson Unit W01 and Reid Unit R01 are above their respective CAIR allocation requirements. Systemwide SO_2 emissions must be reduced by zero to approximately 4% to achieve systemwide compliance with the CAIR Phase I SO_2 allowance requirements.
	Wilson	9,438 (18,876)	12,461	(6,415)	
	Sebree	13,325 (26,650)	24,300	(2,350)	
	Systemwide	27,280 (54,560)	52,470	(2,090)	
NOx (Annual)	Coleman	5,487	2,679	(2,808)	Units equipped with SCR currently generate surplus NOx allocations that can be used to offset excess NOx emissions from other units. Based on 2010 heat inputs, annual and ozone season NOx emissions exceeded the respective CAIR Phase I NOx allocations by approximately 6% and 3.4%, respectively. Relatively small NOx emission reductions on the Coleman Units (from 0.33 to 0.28 lb/MMBtu) could provide the emissions reductions needed to meet the CAIR Phase I allowanced requirements.
	Wilson	934	3,210	NA	
	Sebree	5,653	5,462	(191)	
	Systemwide	12,074	11,351	(723)	

3.2 Cross-State Air Pollution Rule

On August 8, 2011, EPA published the final Cross-State Air Pollution Rule ("CSAPR") in the Federal Register. The rule will replace EPA's 2005 Clean Air Interstate Rule (CAIR) beginning in January 2012. Like CAIR, CSAPR is intended to implement the Clean Air Act requirements concerning the transport of air pollutants across state boundaries, and assist downwind states to attain and maintain the National Ambient Air Quality Standards for ozone and $PM_{2.5}$. Existing ozone and fine particulate matter nonattainment areas in the eastern U.S. are shown in Figure 3-1.

EPA used air quality modeling to determine whether each state contributed to downwind air quality problems. If a state's contribution did not exceed specific thresholds, its contribution was found to be insignificant and it was no longer considered in the analysis. In the rule, EPA concluded that emissions of SO_2 and NOx in 27 states contribute significantly to nonattainment, or interference with maintenance, in at least one downwind state with respect to one or more of three ambient air quality standards – the 1997 annual $PM_{2.5}$ NAAQS; the 2006 24-hour average $PM_{2.5}$ NAAQS; and the 1997 ozone NAAQS. Figure 3-2 is EPA's Air Quality Transport map showing the modeled links between emission sources and downwind nonattainment areas.

Figure 3-1
Existing Ozone and $PM_{2.5}$ Nonattainment Areas

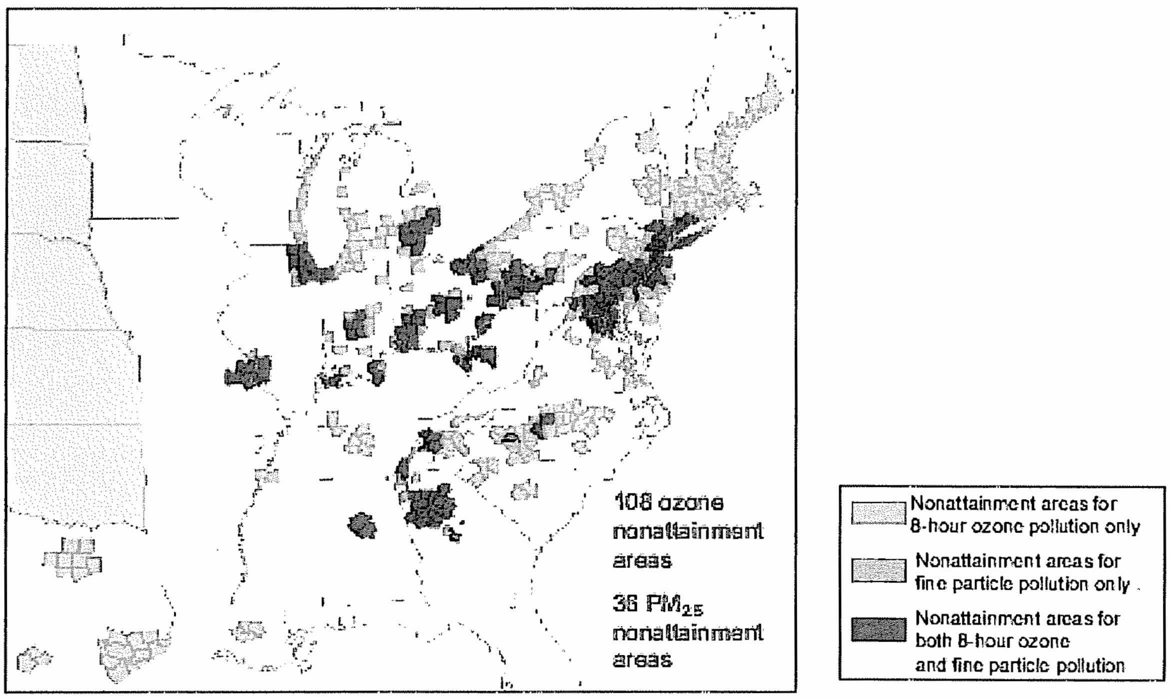
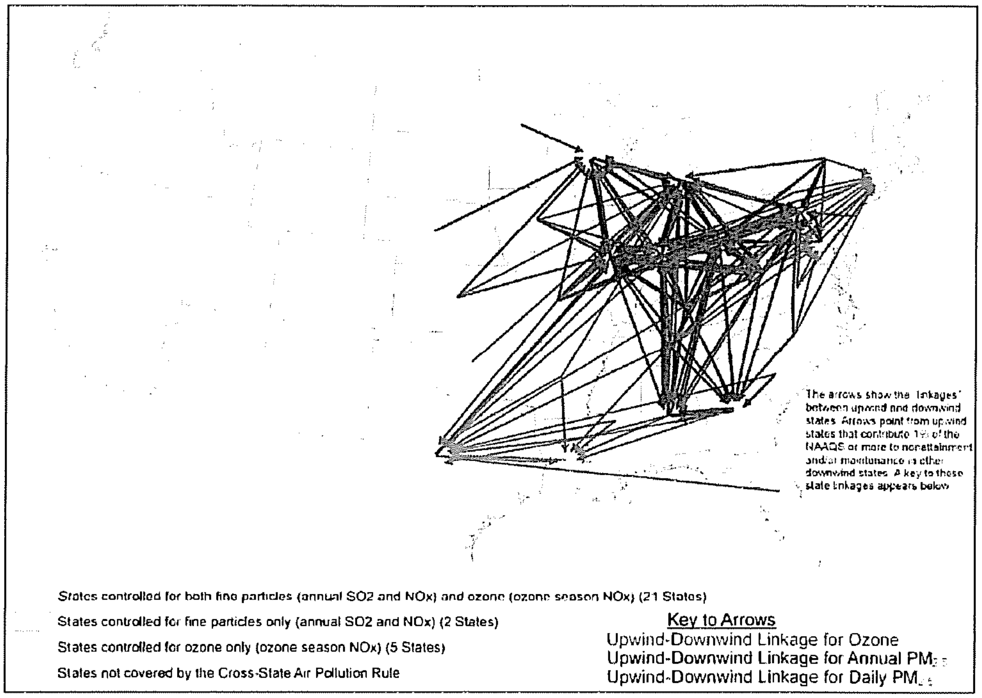


Figure 3-2
USEPA Air Quality Transport: States Linked to Downwind Nonattainment[5]



EPA modeling concluded that SO_2 and NOx emissions from fossil fuel-fired power plants located in Kentucky contributed to fine particulate and ozone NAAQS nonattainment in one or more downwind states (Figure 3-2). Thus, CSAPR regulates annual SO_2 emissions, as well as annual and ozone season NOx emissions from Kentucky power plants as precursors to downwind $PM_{2.5}$ and ozone formation.

3.2.1 CSAPR Trading Programs

Specifically, CSAPR proposes to eliminate emissions that contribute to downwind nonattainment or interfere with maintenance by imposing new SO_2 and NOx cap-and-trade programs. Initially, EPA will implement CSAPR thorough Federal Implementation Plans (FIPs) regulating EGU emissions in 27 states. Each state has the option of replacing the federal rule with a State Implementation Plan (SIP) that achieves the required amount of emission reductions from sources selected by the state. However, because of the process that must be followed to revise a SIP, it is unlikely any states will replace the federal rule prior to 2014.

The final rule includes four discrete types of emissions allowances for four separate cap-and-trade programs: an annual NOx trading program, an ozone season NOx trading program, and two separate SO_2 trading programs ("SO_2 Group 1" and "SO_2 Group 2"). The first phase of CSAPR compliance commences January 1, 2012 for SO_2 and annual NOx reductions, and May 1, 2012 for ozone season NOx reductions. The second phase of CSAPR, which commences January 1, 2014,

[5] From, U.S.EPA Office of Air and Radiation, Final Air Pollution Cross-State Air Pollution Rule Presentation, available at: http://www.epa.gov/airtransport/intex.html.

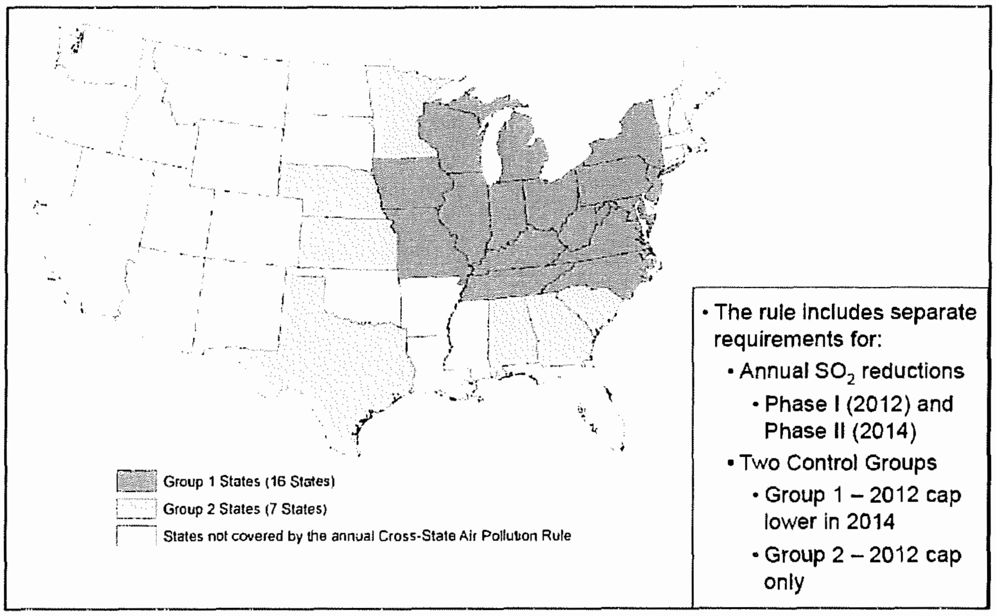
requires more stringent SO_2 emission reductions in the sixteen SO_2 Group 1 states. More stringent SO_2 reduction will not be required in the Group 2 states.[6] States in the SO_2 Group 1 include: Illinois, Indiana, Iowa, **Kentucky**, Maryland, Michigan, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and Wisconsin. Figure 3-3 shows the CSAPR affected states, and Figure 3-4 shows the SO_2 Group 1 and Group 2 states.

Because emissions from Kentucky were determined to contribute to nonattainment with the annual and/or 24-hour $PM_{2.5}$ NAAQS, as well as the 8-hour ozone NAAQS, sources in Kentucky will be subject to the SO_2 Group 1, Annual NOx, and Ozone Season NOx cap-and-trade programs.

Figure 3-3
Cross-State Air Pollution Rule States

[6] States in the SO_2 Group 2 include Alabama, Georgia, Kansas, Minnesota, Nebraska, South Carolina, and Texas.

Figure 3-4
Cross-State Air Pollution Rule: SO_2 Group 1 & Group 2 States



3.2.1.1 **CSAPR Allowance Budgets and Allocations**

In developing the rule, EPA used a state-specific methodology to identify emission reductions that must be made in covered states to eliminate contributions to downwind nonattainment. EPA used air quality analyses to determine the quantity of emissions that each upwind state must eliminate (i.e., the state's significant contribution to nonattainment and interference with maintenance), and to establish individual state budgets for emissions from covered units. The final rule includes SO_2 and annual NOx budgets for each state covered for the 24-hour and/or annual $PM_{2.5}$ NAAQS (including Kentucky), and ozone season NOx budgets for each state covered for the 8-hour ozone NAAQS (also including Kentucky). A state's emission budget is the quantity of emissions from covered units after elimination of significant contribution. CSAPR emission budgets include provisions for new unit set-asides, and provisions to account for the inherent variability in power system operations.

The final rule allocates a specific percentage of each states' emission budget for new units. A "new unit" may be any of the following: (1) a covered unit commencing commercial operation on or after January 1, 2010; (2) any unit that becomes a covered unit by meeting applicability criteria subsequent to January 1, 2010; (3) any unit that relocates into a different state covered by CSAPR; and (4) any existing covered unit that stopped operating for 2 consecutive years but resumes commercial operation at some point thereafter.[7]

EPA established each state's new unit set-aside by accounting for both "potential" units (i.e., those that are not yet planned or under construction but are projected by modeling to be built) and "planned" units (i.e., those that are known units with planned online dates after January

[7] See, 76 FR 48290, col. 1.

1, 2010). In general, EPA established a minimum new unit set-aside equal to 2% of each state's budget to accommodate future potential units. EPA increased the new unit set-aside above the 2% minimum for states that had additional known units coming online between January 1, 2010, and January 1, 2012.[8] Based on this evaluation, EPA allocated 6% of Kentucky's annual SO_2 budget, and 4% of the state's annual and ozone season NOx budgets to the state's new unit set-aside. The final rule also establishes an Indian country new unit set-aside for each state whose borders encompass Indian country (which did not include Kentucky).

Because of unavoidable variability in baseline emissions resulting from inherent variability in power plant operations, EPA concluded that state-level emissions may vary somewhat after all significant contribution to downwind nonattainment has been eliminated. EPA analyzed historical heat input data to quantify the magnitude of the variability in each state, and to establish the variability limits.[9] CSAPR accounts for the inherent variability in power system operations through "assurance provisions." The assurance provisions cap the number of additional allowances that can be purchased from out-of-state sources based on state-specific variability limits. Emission budgets plus variability limits establish each state's "assurance level."

The Kentucky CSAPR SO_2, annual NOx, and ozone season NOx state budgets, new unit set-asides, and respective variability limits are summarized in Table 3-7.

Table 3-7
Kentucky CSAPR Emission Budgets and Variability Limits[(1)]

Kentucky CSAPR Allowance Budgets	2012 SO_2 Allocations	2014 SO_2 Allocations	2012 Annual NOx Allocations	2014 Annual NOx Allocations	2012 Ozone-Season NOx Allocations	2014 Ozone-Season NOx Allocations
Allocations[(2)] (tons)	218,702	99,907	81,683	74,148	34,720	31,367
New Unit Set-Aside (tons)	13,960	6,377	3,403	3,090	1,447	1,307
Variability Limits (tons)	41,879	19,131	15,315	13,903	7,595	6,862
State Assurance Level (tons)	274,541	125,415	100,401	91,141	43,762	39,536

(1) CSAPR Final Rule, 76 FR 48269-48270
(2) Adjusted for new unit set aside.

State-specific emission budgets (without the variability limits) were used to determine the number of emission allowances allocated to sources within the state. In general, emission allowances were allocated to each individual unit based on that unit's share of the state's historic heat input, as long as individual unit allocations did not exceed each units' maximum annual historic emissions rate (during the 8-year baseline period of 2003-2010). The heat input-based allowance methodology used by EPA was fuel-neutral, control-neutral, and based on historic heat

[8] 76 FR 48291, col. 3.
[9] See e.g., 76 FR 48266, col. 2.

input data submitted by existing units pursuant to the Acid Rain Program.[10] A summary of the baseline heat input data used by EPA to calculate the BREC allowance allocations, and a summary of the CSAPR SO_2 and NOx allowance allocations, are provided in Tables 3-8a and 3-8b, respectively.

Table 3-8a
BREC CSAPR SO_2 Allocations (2012 and 2014)

BREC Unit	Baseline Annual Heat Input (MMBtu)	Percentage Share of State Annual Heat Input	CSAPR Annual SO_2 Allocations (2012) (tpy)	CSAPR Annual SO_2 Allocations (2014) (tpy)
Kentucky	**1,055,615,936**	--	**218,702**	**99,907**
Coleman Unit C01	11,784,789	1.116%	2,672	1,150
Coleman Unit C02	11,787,242	1.117%	2,673	1,150
Coleman Unit C03	12,570,106	1.191%	2,850	1,226
Wilson Unit W01	37,043,481	3.509%	8,400	3,614
Green Unit G01	20,128,359	1.907%	2,078	1,964
Green Unit G02	20,347,531	1.928%	1,771	1,771
HMP&L Unit H01	12,823,005	1.215%	2,518	1,251
HMP&L Unit H02	13,214,893	1.252%	2,997	1,289
Reid Unit R01	2,240,807	0.212%	508	219
Reid Unit RT	87,379	0.008	11	9
Total	142,027,592	13.46%	26,478	13,643

Table 3-8b
BREC CSAPR Annual & Ozone Season NOx Allocations (2012 and 2014)

BREC Unit	CSAPR Annual NOx Allocations (tpy)		CSAPR Ozone Season NOx (tpy)	
	2012	**2014**	**2012**	**2014**
Kentucky	**81,683**	**74,148**	**34,720**	**31,367**
Coleman Unit C01	928	841	402	356
Coleman Unit C02	928	842	407	360
Coleman Unit C03	990	898	439	389
Wilson Unit W01	2,918	2,645	1,333	1,180
Green Unit G01	1,585	1,437	696	616
Green Unit G02	1,603	1,453	702	622
HMP&L Unit H01	1,010	916	447	396
HMP&L Unit H02	1,041	944	464	411
Reid Unit R01	176	160	77	68
Reid Unit RT	7	6	5	4
Total	11,186	10,142	4,972	4,402

[10] A detailed description of the allowance allocation methodology is included on pages 48289-48291 of the final rule.

3.2.1.2 **CSAPR Allowance Holding Requirements**

An EGU source is required to hold one SO_2 or one NOx allowance, respectively, for every ton of SO_2 or NOx emitted during the control period. Allowances can be used for compliance in the year for which the allowance was allocated or a later year, and banking of allowances for use in future years is allowed. Once a control period has ended (i.e., December 31 for CSAPR SO_2 and annual NOx trading programs and September 30 for the ozone season NOx trading program), covered sources have until March 1 or December 1 following the annual and ozone season control periods, respectively, to evaluate their reported emissions and obtain any allowances they might need to cover their emissions during the control period.[11]

The rule includes intrastate and limited interstate allowance trading. A source located in one of the sixteen SO_2 Group 1 states can trade SO_2 allowances only with facilities located in another Group 1 state. Similarly, a source located in one of the seven SO_2 Group 2 states can only trade SO_2 allowances allocated to units located in other Group 2 states. For compliance with the annual and ozone season NOx trading programs, sources may use NOx allowances allocated to any state for the respective trading programs, even if that state is in a different group for SO_2 than the source's state.

If the owner/operator of a CSAPR unit fails to meet its allowance-holding requirement, they must provide for deduction from the source's compliance account, one allowance as an offset and one allowance as an excess emissions penalty, for each ton of emissions in excess of the amount of allowances held. The allowance surrendered for the excess emissions penalty must be allocated for the control period in the year immediately following the year when the excess emissions occurred or for a control period in any prior year. The offset and excess emissions penalty are automatic requirements in that they must be met without any further proceedings by EPA regardless of the reason for the occurrence of the excess emissions. In addition, each ton of excess emissions, as well as each day in the averaging period (i.e., the control period of one calendar year), constitute a violation of the CAA, and the maximum discretionary civil penalty is $37,500 (for 2010) per violation under CAA §113.

3.2.1.3 **CSAPR Assurance Provisions**

The final rule allows interstate trading to account for variability, but also includes assurance provisions to ensure that the necessary emission reductions occur within each covered state. The assurance provisions restrict EGU emissions within each state to the state's budget plus the variability limit. The final rule implements these assurance provisions starting in 2012.

For any single year, emissions from CSAPR-affected units located within a state cannot exceed the state budget with the variability limit (i.e., the assurance level). Assurance provisions included in the final rule effectively limit the number of out-of-state allowances that facilities can purchase without risk of penalty. In the event total emissions exceed the state's assurance level,

[11] See, 76 FR 48340 col. 3. The CSAPR cap-and-trade programs would be independent of the existing Acid Rain Program, and Title IV ARP allowances would not be available for compliance with CSAPR allowance requirements. Therefore, there is no SO_2 allowances carried over from the Acid Rain Program to CSAPR. The ARP will continue as a separate program, and ARP allowances would continue to be used to meet each unit's ARP allowance requirements.

units contributing to the exceedence will be subject to additional allowance surrender requirements.

The final rule includes specific criteria that EPA will used to determine which units, with a common designated representative (DR), will be subject to the additional allowance surrender requirements. The requirement that owners/operators surrender allowances under the assurance provisions will be triggered if: (1) total state EGU emissions for a control period exceed the state assurance level; and (2) the group of units with a common DR had emissions exceeding the respective DR's share of the state assurance level. The share of the assurance penalty borne by the group will be based on the amount by which the total emissions from the group exceed the common DR's share of the state assurance level.[12] If the group's emissions do not exceed the common DR's share of the state assurance level, the group will not be subject to the allowance surrender provisions, even if statewide EGU emissions exceed the assurance level.

The owners/operators of each such group of sources and units that exceed the DR's share of the state's assurance level must surrender an amount of allowances equal to the excess of state EGU emissions (over the state assurance level) multiplied by the groups' percentage and multiplied by two (to reflect the penalty of two allowances for each ton of excess emissions). An example of the assurance provision allowance surrender requirements is provided in Table VII.E-1, page 48296 of the final rule.

The BREC share of Kentucky's assurance level would equal approximately 13.5% of the state's variability limit (based on historic baseline annual heat input data). In others words, BREC should be able to purchase the following number of out-of-state allowances without incurring the assurance provision allowance surrender requirements, even if statewide EGU emissions exceed the respective assurance levels:

- 2012 SO_2 allowances: 5,654
- 2104 SO_2 allowances: 2,583
- 2012 Annual NOx allowances: 2,068
- 2014 Annual NOx allowances: 1,877
- 2012 Ozone Season NOx allowances: 1,025
- 2014 Ozone Season NOx allowances: 926

Emissions from a common DR's group of units in excess of the DR's share of the state budget are not a violation of the rule or the CAA, but do lead to strict allowance surrender requirements. Failing to hold sufficient allowances to meet the allowance surrender requirement will be a violation of the regulations and the CAA. Allowances surrendered to meet an assurance provision penalty may be from the year immediately following the control period in which the state assurance level was exceeded or any prior year. Any future vintage allowances beyond the year in which the penalty is assessed may not be used to meet an assurance provision penalty.

[12] A more detailed description of the assurance provisions is included on page 48294 of the final rule

3.2.1.4 CSAPR SO2 Allocations

CSAPR annual SO_2 allocations for the BREC generating units for 2012 and 2014 are summarized in Tables 3-9 and 3-10, respectively. Tables 3-9 and 3-10 also compare CSAPR SO_2 allocations to the annual SO_2 emissions from each unit. Baseline average emissions shown in Table 3-9 and 3-10 were calculated as the average of the three highest emission years for each unit between the years 2006 and 2010. Using baseline annual heat inputs to each unit (calculated as the average of the three highest heat input years for each unit between the years 2006 and 2010), the respective SO_2 emission rates that need to be achieved in 2012 and 2014 to match the CSAPR SO_2 allowance allocations were calculated and are shown in Tables 3-9 and 3-10.

Table 3-9
BREC CSAPR Annual 2012 SO_2 Allocations and Calculated Allowance Equivalent Emission Rates

BREC Unit	Allocations (CSAPR) (tons)	Annual SO2 Emissions (3/5 2006-2010) (tons)	Allowance Surplus or (Deficit) (tons)	Allowance Equivalent Emission Rate (lb/MMBtu)	Actual Annual Emission Rate (lb/MMBtu)	% Reduction
Coleman Unit C01	2,672	1,473	1,199	0.453	0.250	NA
Coleman Unit C02	2,673	1,473	1,200	0.454	0.250	NA
Coleman Unit C03	2,850	1,571	1,279	0.453	0.250	NA
Wilson Unit W01	8,400	9,438	(1,038)	0.454	0.510	11.0%
Green Unit G01	2,078	1,873	205	0.206	0.186	NA
Green Unit G02	1,771	1,414	357	0.174	0.139	NA
HMP&L Unit H01	2,518	2,227	291	0.393	0.347	NA
HMP&L Unit H02	2,997	2,745	252	0.454	0.415	NA
Reid Unit R01	508	5,066	(4,558)	0.453	4.522	90.0%
Reid Unit RT	11	5	6	0.252	0.117	NA
Total	26,478	27,286	(808)	0.373	0.384	2.9%

(1) Baseline annual heat inputs are calculated as the average of the three highest heat input years for each unit between the years 2006 and 2010; however, baseline SO_2 emissions from Coleman Units C01, C02, and C03 were adjusted to an annual average emission rate of 0.25 lb/MMBtu based on information provided by BREC.

Table 3-10
BREC CSAPR Annual 2014 SO_2 Allocations and Calculated Allowance Equivalent Emission Rates

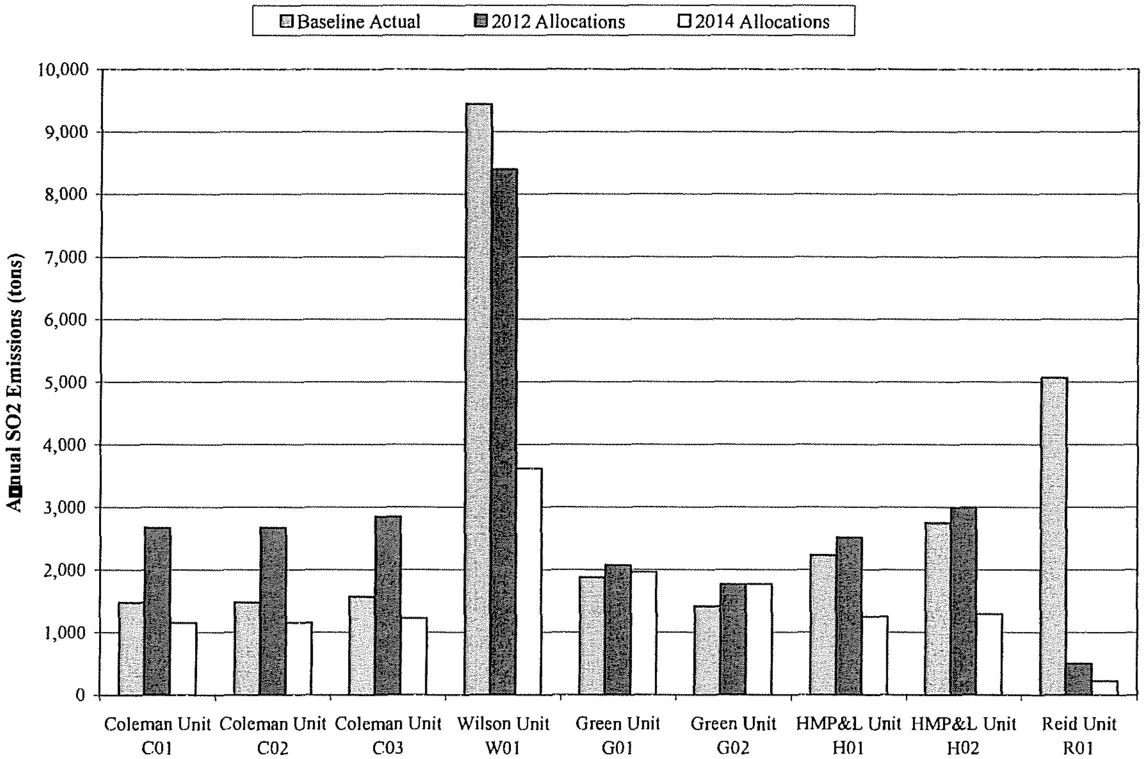
BREC Unit	Allocations (CSAPR) (tons)	Annual SO2 Emissions (3/5 2006-2010) (tons)	Allowance Surplus or (Deficit) (tons)	Allowance Equivalent Emission Rate (lb/MMBtu)	Actual Annual Emission Rate (lb/MMBtu)	% Reduction
Coleman Unit C01	1,150	1,473	(323)	0.195	0.250	22.0%
Coleman Unit C02	1,150	1,473	(323)	0.195	0.250	22.0%
Coleman Unit C03	1,226	1,571	(345)	0.195	0.250	22.0%
Wilson Unit W01	3,614	9,438	(5,824)	0.195	0.510	61.8%
Green Unit G01	1,964	1,873	91	0.195	0.186	NA
Green Unit G02	1,771	1,414	357	0.174	0.139	NA
HMP&L Unit H01	1,251	2,227	(976)	0.195	0.347	43.8%
HMP&L Unit H02	1,289	2,745	(1,456)	0.195	0.415	53.0%
Reid Unit R01	219	5,066	(4,847)	0.195	4.522	95.7%
Reid Unit RT	9	5	4	0.206	0.117	NA
Total	13,643	27,286	(13,643)	0.192	0.384	50.0%

(1) Baseline annual heat inputs are calculated as the average of the three highest heat input years for each unit between the years 2006 and 2010; however, baseline SO_2 emissions from Coleman Units C01, C02, and C03 were adjusted to an annual average emission rate of 0.25 lb/MMBtu based on information provided by BREC.

BREC generating units will receive 26,478 SO_2 allocations in 2012 and 13,643 SO_2 allocations in 2014. By comparison, annual SO_2 emissions from the BREC generating units averaged between 25,575 tpy (actual average) and 27,286 tpy (average of the three highest years during the baseline period).

Assuming boiler capacity factors and SO_2 emission rates remain relatively constant, SO_2 emissions from the BREC units should be at, or below, the 2012 CSAPR allocations. However, SO_2 emission reductions will be needed prior to the 2014 Group 1 SO_2 cap reductions. Average SO_2 emissions from the units (25,575 – 27,286 tpy) exceed the 2014 allowance allocations of 13,643 tons by approximately 50%. Figure 3-5 shows the annual SO_2 mass emissions from each BREC generating unit, as well as the 2012 and 2014 CSAPR allocations. It can be seen that SO_2 emissions from all units, except Green Units G01 and G02, exceed their 2014 CSAPR allocations.

Figure 3-5
CSAPR SO_2 Allocations vs. Annual SO_2 Emissions



A majority of the 2014 allowance shortfall is associated with SO_2 emissions from Wilson Unit W01 and Reid Unit R01. SO_2 emissions from Wilson Unit W01 have averaged approximately 9,438 tpy, compared to the unit's 2012 and 2014 SO_2 allocations of 8,400 and 3,614 tons, respectively. Similarly, SO_2 emissions from Reid Unit R01 have averaged approximately 5,066 tpy, compared to the unit's 2014 SO_2 allocations of 219 tons. The Coleman and HMP&L Generating Stations are also projected to have 2014 SO_2 allowance deficiencies of 991 and 2,432 tons, respectively.

Assuming a total annual heat input to the BREC generating units of approximately 142,000,000 MMBtu, systemwide SO_2 emissions would have to average approximately 0.19 lb/MMBtu to meet the CSAPR 2014 allocations. A systemwide average emission rate of 0.19 lb/MMBtu is approximately 50% below the current systemwide average emission rate of 0.38 lb/MMBtu.

3.2.1.5 CSAPR NOx Allocations

CSAPR annual and ozone season NOx allocations for the BREC generating units for 2012 and 2014 are summarized in Tables 3-11 and 3-12, respectively. Tables 3-11 and 3-12 also compare CSAPR NOx allocations to the 2010 baseline NOx emissions from each unit. Figures 3-

6 and 3-7 show the baseline annual and ozone season NOx emissions from each unit compared to the CSAPR NOx allocations.

Table 3-11a
Baseline Annual NOx Emissions vs. CSAPR Annual NOx Allowances (2012)

BREC Unit	CSAPR Annual NOx Allowances (tons) (2012)	Annual NOx Emissions (tons) (2010)	Allowance Surplus or (Deficit) (tons)	Allowance Equivalent Emission Rate (lb/MMBtu)	Baseline Emission Rate (lb/MMBtu)	% Reduction
Coleman Unit C01	928	1,858	(930)	0.165	0.330	50.00%
Coleman Unit C02	928	1,585	(657)	0.194	0.332	41.60%
Coleman Unit C03	990	2,044	(1054)	0.162	0.335	51.60%
Wilson Unit W01	2,918	934	1984	0.161	0.052	NA
Green Unit G01	1,585	2,050	(465)	0.16	0.206	22.30%
Green Unit G02	1,603	2,168	(565)	0.159	0.215	26.00%
HMP&L Unit H01	1,010	460	550	0.155	0.071	NA
HMP&L Unit H02	1,041	418	623	0.172	0.069	NA
Reid Unit R01	176	512	(336)	0.179	0.522	65.70%
Reid Unit RT	7	45	(38)	0.111	0.708	84.30%
Total	11,186	12,074	(888)	0.164	0.177	7.30%

Table 3-11b
Baseline Annual NOx Emissions vs. CSAPR Annual NOx Allowances (2014)

BREC Unit	CSAPR Annual NOx Allowances (tons) (2014)	Annual NOx Emissions (tons) (2010)	Allowance Surplus or (Deficit) (tons)	Allowance Equivalent Emission Rate (lb/MMBtu)	Baseline Emission Rate (lb/MMBtu)	% Reduction
Coleman Unit C01	841	1,858	(1017)	0.149	0.330	54.80%
Coleman Unit C02	842	1,585	(743)	0.176	0.332	47.00%
Coleman Unit C03	898	2,044	(1146)	0.147	0.335	56.10%
Wilson Unit W01	2,645	934	1711	0.146	0.052	NA
Green Unit G01	1,437	2,050	(613)	0.145	0.206	29.60%
Green Unit G02	1,453	2,168	(715)	0.144	0.215	33.00%
HMP&L Unit H01	916	460	456	0.141	0.071	NA
HMP&L Unit H02	944	418	526	0.156	0.069	NA
Reid Unit R01	160	512	(352)	0.163	0.522	68.80%
Reid Unit RT	6	45	(39)	0.095	0.708	86.60%
Total	10,142	12,074	(1932)	0.149	0.177	15.80%

Table 3-12a
Baseline Ozone Season NOx Emissions vs. CSAPR Ozone Season NOx Allowances (2012)

BREC Unit	CSAPR Annual NOx Allowances (tons) (2012)	Annual NOx Emissions (tons) (2010)	Allowance Surplus or (Deficit) (tons)	Allowance Equivalent Emission Rate (lb/MMBtu)	Baseline Emission Rate (lb/MMBtu)	% Reduction
Coleman Unit C01	402	733	(331)	0.182	0.332	45.20%
Coleman Unit C02	407	735	(328)	0.185	0.335	44.80%
Coleman Unit C03	439	857	(418)	0.173	0.337	48.70%
Wilson Unit W01	1,333	378	955	0.175	0.05	NA
Green Unit G01	696	789	(93)	0.178	0.202	11.90%
Green Unit G02	702	890	(188)	0.167	0.212	21.20%
HMP&L Unit H01	447	208	239	0.16	0.074	NA
HMP&L Unit H02	464	179	285	0.173	0.066	NA
Reid Unit R01	77	193	(116)	0.187	0.467	60.00%
Reid Unit RT	5	33	(28)	0.105	0.7	85.00%
Total	4,972	4,995	(23)	0.174	0.175	0.60%

Table 3-12b
Baseline Ozone Season NOx Emissions vs. CSAPR Ozone Season NOx Allowances (2014)

BREC Unit	CSAPR Annual NOx Allowances (tons) (2014)	Annual NOx Emissions (tons) (2010)	Allowance Surplus or (Deficit) (tons)	Allowance Equivalent Emission Rate (lb/MMBtu)	Baseline Emission Rate (lb/MMBtu)	% Reduction
Coleman Unit C01	356	733	(377)	0.161	0.332	51.50%
Coleman Unit C02	360	735	(375)	0.164	0.335	51.00%
Coleman Unit C03	389	857	(468)	0.153	0.337	54.60%
Wilson Unit W01	1,180	378	802	0.155	0.05	NA
Green Unit G01	616	789	(173)	0.158	0.202	21.80%
Green Unit G02	622	890	(268)	0.148	0.212	30.20%
HMP&L Unit H01	396	208	188	0.142	0.074	NA
HMP&L Unit H02	411	179	232	0.153	0.066	NA
Reid Unit R01	68	193	(125)	0.165	0.467	64.70%
Reid Unit RT	4	33	(29)	0.084	0.7	88.00%
Total	4,402	4,995	(593)	0.154	0.175	12.00%

Figure 3-6
Annual NOx Emissions and CSAPR Annual NOx Allowances (2012 & 2014)

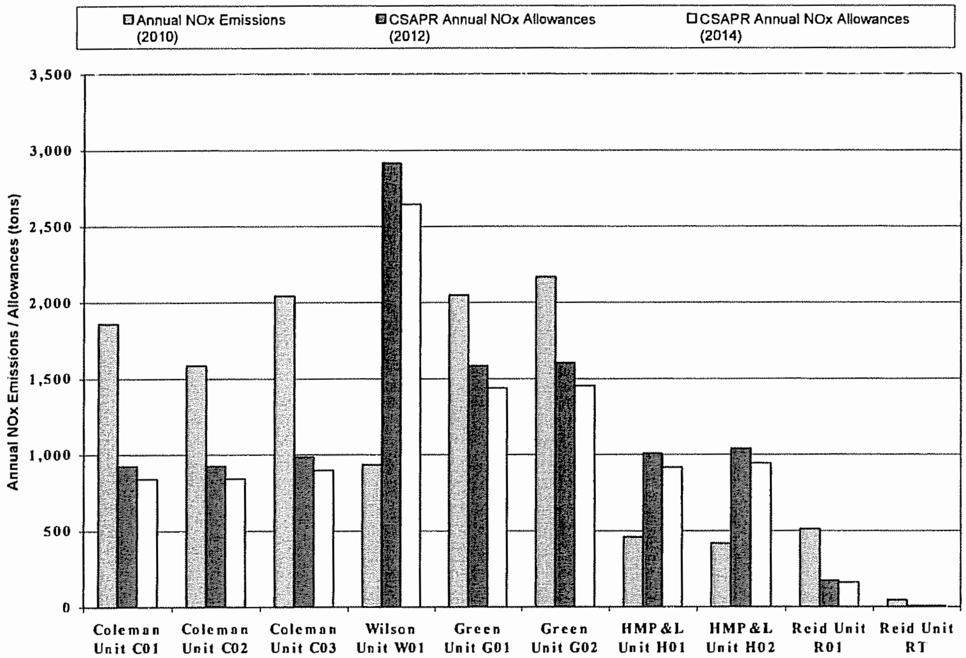
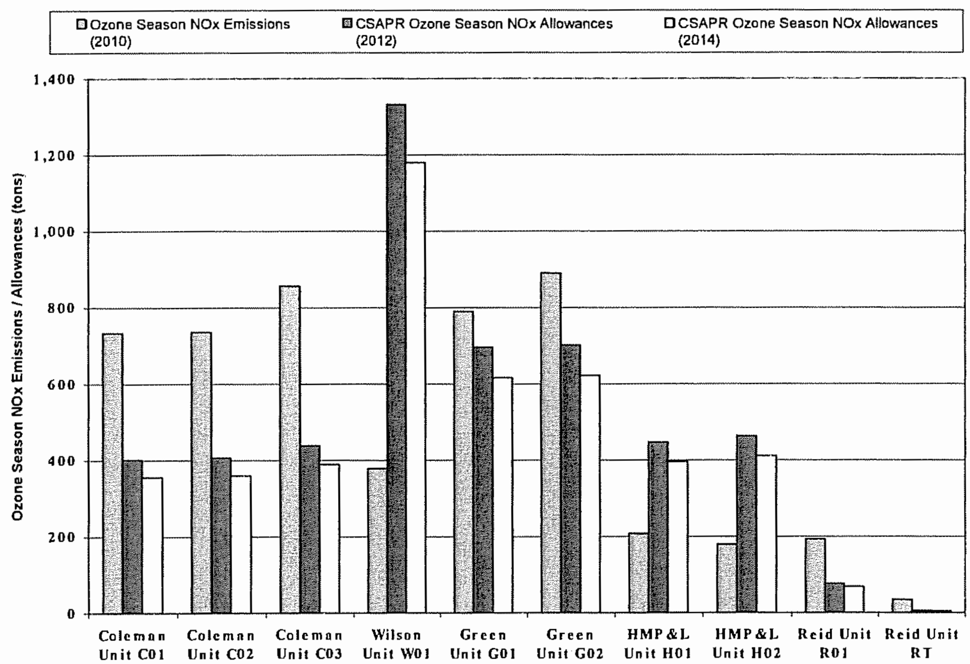


Figure 3-7
Ozone Season NOx Emissions and CSAPR Ozone Season NOx Allowances (2012 & 2014)



It can be seen that NOx emissions from Wilson Unit W01 and HMP&L Units H01 and H02 are below their CSAPR allocations (annual and ozone season). These units are equipped with SCR and currently achieve controlled NOx emission rates in the range of 0.052 to 0.071 lb/MMBtu. NOx emissions from the remaining units exceed their respective allocations. Using 2010 NOx emissions and heat input data as the baseline,[13] the NOx emission rates, and the emission reductions needed to match the annual and ozone season CSAPR NOx allocations were calculated and are shown in Tables 3-11 and 3-12, respectively.

Emissions and allocation data summarized in Tables 3-11a and 3-11b show that BREC needs to reduce NOx emissions from all generating units by approximately 7% in 2012 and 16% in 2014 to meet its CSAPR annual NOx allowance requirements. BREC will receive 11,186 annual NOx allowances in 2012 and 10,142 allowances in 2014, compared to its 2010 annual NOx emissions of 12,074 tons.

Similarly, emissions and allocation data summarized in Tables 3-12a and 3-12b show that BREC needs to reduce seasonal NOx emissions by approximately 1% in 2012 and 12% in 2014 to meet its CSAPR ozone season NOx allowance requirements. BREC will receive 4,972 ozone season NOx allowances in 2012 and 4,402 allowances in 2014, compared to its 2010 ozone season NOx emissions of 4,995 tons.

NOx emissions from Wilson Unit W01, HMP&L Unit H01, and HMP&L Unit H02 (equipped with SCR) are below their respective allocations. Based on the allocations in Tables 3-11 and 3-12, these three units should generate approximately 2,693 annual and 1,222 seasonal NOx allocations in 2014 that can be used to offset NOx emissions from other units. Conversely, the Coleman Station, Green Station, and Reid Station will have excess NOx emissions of approximately 4,679 tons (annual) and 1,833 tons (seasonal) in 2014.

Assuming a total annual heat input to all BREC generating units in the range of 136,400,000 MMBtu, and a total ozone season heat input to all units in the range of 57,200,000 MMBtu, NOx emissions from all BREC units would have to average approximately 0.15 lb/MMBtu to maintain NOx emissions below the annual and ozone season CSAPR NOx allocations. A systemwide average emission rate of 0.15 lb/MMBtu is approximately 16% below the current systemwide average NOx emission rate of 0.177 lb/MMBtu.

3.2.2 CSAPR Summary

The Cross-State Air Pollution Rule will replace CAIR in 2012. The rule includes a new SO_2 cap-and-trade program, as well as new annual and ozone season NOx trading programs. Potential impacts of the CSAPR are summarized below.

3.2.2.1 CSAPR SO2 Summary & Conclusions

BREC generating stations will receive 26,478 SO_2 allowances in 2012, and 13,643 allowances in 2014. These allowances compare to systemwide baseline SO_2 emissions in the range of 25,757 tpy (actual average) to approximately 27,286 tpy (average of three highest

[13] 2010 NOx emissions were determined to be more representative of the emissions going forward than NOx emissions from previous years. Therefore, 2010 emissions and heat input data were used for the Cross-State Air Pollution Rule NOx evaluation.

emissions years). Using the baseline SO_2 emissions and annual unit heat input data summarized in Tables 3-9 and 3-10, SO_2 emissions from the BREC generating stations should be at, or slightly below, their CSAPR allowances in 2012. However, systemwide SO_2 emissions must be reduced by approximately 50% to match the 2014 CSAPR SO_2 allocations.

3.2.2.2 **CSAPR NOx Summary & Conclusions**

BREC will receive 11,186 annual NOx allowances in 2012 and 10,142 annual NOx allowances in 2014. Actual NOx emissions from the BREC units totaled 12,074 tons in 2010, approximately 16% above the 2014 CSAPR allowances. BREC will also receive 4,972 seasonal NOx allowances in 2012 and 4,402 seasonal NOx allowances in 2014. Actual ozone season NOx emissions from the BREC units totaled 4,995 tons in 2010, approximately 12% above the 2014 seasonal NOx allowance allocation. To meet its 2014 CSAPR annual and ozone season NOx allowances, systemwide NOx emissions from the BREC generating units must be reduced by approximately 16%, to an average systemwide NOx emission rate of approximately 0.15 lb/MMBtu.

3.3 Proposed Utility MACT Rule

On May 3, 2011, EPA published in the Federal Register a proposed rule regulating hazardous air pollutant (HAP) emissions from coal and oil-fired electric generating units (the "Proposed Utility MACT").[14] The rule proposed regulating HAP emissions from coal and oil-fired electric generating units (EGUs) pursuant to §112 of the CAA. Section 112(d) of the Act requires the control of HAP emissions using the maximum achievable control technology (MACT). The proposed rule includes emission standards and work practice standards that will apply to all existing and new coal and oil-fired EGUs. Publication of the proposed rule in the Federal Register opened a 60-day public comment period on the proposal. After the close of the public comment period, EPA is required to review and respond to all substantive comments, and sign for publication a final rule by November 16, 2011.

3.3.1 Applicability

The Proposed Utility MACT applies to new and existing coal and oil-fired EGUs. An EGU is defined in the rule as a fossil fuel-fired combustion unit of more than 25 MW that serves a generator that produces electricity for sale. In the proposed rule, EPA proposed the following tests to determine whether a unit is considered to be fossil fuel-fired: (1) the unit must be capable of combusting more than 250 MMBtu/hr of coal or oil; and (2) the unit must have fired coal or oil for more than 10% of the average annual heat input during the previous 3 calendar years, or for more than 15% of the annual heat input during any one of those calendar years. These tests exclude from the definition of EGU natural gas-fired boilers and biomass-fired units that fire limited quantities of coal or oil.

The proposed rule includes HAP emission limits for both new and existing units. Existing units include coal-fired EGUs that are already operating, as well as those for which construction or reconstruction began prior to publication of the proposed rule in the Federal Register.

All of the BREC coal-fired generating units, including units C01, C02, C03, W01, G01, G02, H01, H02, and R01, are existing fossil-fuel fired EGUs, and will be subject to the Utility MACT Rule.

[14] 76 Fed. Reg. 24976, May 3, 2011.

3.3.2 Proposed Source Subcategories

EPA proposed subcategorizing the coal-fired EGU source category as follows:

Subcategory	Description
Coal-fired unit designed for coal ≥ 8,300 Btu/lb	1. combusts coal; 2. meets the proposed definition of "fossil fuel fired;" and 3. burns any coal in an EGU designed to burn a coal having a calorific value (moist, mineral matter-free basis) of ≥ 8,300 Btu/lb in an EGU with a height-to-depth ratio of <3.82.
Coal-fired unit designed for coal <8,300 But/lb if:	1. combusts coal; 2. meets the proposed definition of "fossil fuel fired;" and 3. burns any virgin coal in an EGU designed to burn a nonagglomerating fuel having a calorific value (moist, mineral matter-free basis) of <8,300 Btu/lb in an EGU with a height-to-depth ratio of 3.82 or greater.

All of the BREC coal-fired boilers fall into the "designed for coal ≥ 8,300 Btu/lb" subcategory, and will be subject to the emission limits and work practice standards proposed for existing units in that subcategory. It should be noted that EPA did not propose different subcategories for bituminous and subbituminous-fired units.

3.3.3 Proposed Utility MACT Emission Limits

The proposed rule includes HAP emission limits and work practice standards for new and existing EGUs in each subcategory. EPA proposed emission limits for mercury (Hg), non-Hg trace metals, and acid gases. Work practiced standards were proposed for the organic HAPs. For the non-Hg trace metals, EPA proposed alternative emission limits for total PM (filterable + condensible), total non-Hg HAP metals, and individual HAP metals. For the acid gases, EPA proposed using either HCl or SO_2 as a surrogate for all acid gas emissions.

Proposed emission limits for the existing coal-fired EGU designed for coal ≥ 8,300 Btu/lb subcategory are summarized in Table 3-13.

Table 3-13
Proposed Emissions Limits for Existing Coal- Fired EGUs

Existing Coal-Fired and Solid Oil-Derived Fuel-Fired EGUs	Non-HG Metals	Acid Gases	Hg
Existing coal-fired unit designed for coal ≥ 8,300 Btu/lb (bituminous- and subbituminous-fired boilers)	**Total PM**[(1)] 0.030 lb/MMBtu or **Total non-Hg HAP Metals**[(2)] 0.000040 lb/MMBtu or **Individual HAP Metals**[(3)]	**HCl** 0.0020 lb/MMBtu [~2 ppmvd @ 3% O_2] or **SO_2**[(4)] 0.20 lb/MMBtu	**Hg** 1.2 lb/TBtu (0.0096 lb/GWh)

(1) The Total PM emission limit includes both filterable and condensible particulate matter.

(2) The Total non-Hg HAP Metals emission limits equals the sum of: Antimony (Sb), Arsenic (As), Beryllium (Be), Cadmium (Cd), Chromium (Cr), Cobalt (Co), Lead (Pb), Manganese (Mn), Nickel (Ni), and Selenium (Se).

(3) As an alternative to the Total PM emission limit and/or the Total non-Hg HAP Metals limit, EPA proposed emission limits for each Individual HAP Metal (see, proposed Table 2 to Subpart UUUUU of Part 63).

(4) You may not use the alternate SO_2 limit if your coal-fired EGU does not have a system using wet or dry FGD installed on the unit.

3.3.4 Proposed Utility MACT Work Practice Standards

In addition to the emission limits summarized above, EPA is proposing a work practice standard for organic HAP emissions, including emissions of dioxins and furans (D/F), non-D/F organic compounds, and hazardous volatile organic compounds, for all EGU subcategories. The work practice standard proposed for all EGUs would require the implementation of an annual performance compliance tune-up program. Although tune-ups are required on an annual basis, the proposed regulations provide some flexibility to allow burner inspections and tune-ups during planned unit shutdowns. Among other things, the annual boiler tune-up would include:

- Inspect the burner, and clean or replace any components of the burner as necessary;
- Inspect the flame pattern, as applicable, and make any adjustments to the burner necessary to optimize the flame pattern;
- Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly;
- Optimize total emissions of CO and NOx. This optimization should be consistent with the manufacturer's specifications, if available; and
- Measure the concentration in the effluent stream of CO and NOx in ppm by volume, before and after the adjustments are made.

3.3.5 Emission Control Technologies and Emission Reduction Requirements

The proposed rule does not mandate specific emission control technologies or emission reduction requirements. Coal and oil-fired EGUs are simply required to meet the applicable HAP emission limits using whatever control technology, or combination of technologies, they deem appropriate for their specific situation. The following subsections compare the Proposed Utility MACT emission limits to stack test data available from the BREC generating units, and provide a brief description of the air pollution control technologies that may be available to meet the proposed MACT limits for existing coal-fired boilers. A detailed evaluation of the air pollution control technologies available to BREC to control HAP emissions will be prepared during the next phase of this project.

3.3.5.1 **Mercury**

Mercury emissions from coal-fired boilers are a complex function of fuel characteristics (including the concentration of mercury and halogens in the coal), fly ash characteristics, combustion controls, and post-combustion air pollution control systems. During combustion, mercury readily volatilizes from the fuel and is found in the flue gas predominantly in the vapor phase as elemental mercury (Hg^o). As the flue gas cools, a series of complex reactions begin to convert Hg^o to gaseous ionic mercury (Hg^{2+}) compounds, and Hg compounds that are in a solid-phase at flue gas temperatures (Hg_p).[15] Mercury speciation testing indicates that the distribution of Hg^0, Hg_p, and Hg^{2+} varies with coal type, and is dependant upon the chloride concentration in the coal.

To a major degree, mercury control is a function of mercury speciation. In general, particulate forms of mercury will be effectively captured in the unit's particulate matter control system, and ionic mercury is water soluble and will be captured in flue gas desulfurization control systems. Elemental mercury is more difficult to capture, and may not be effectively captured in the air pollution control systems designed to capture more conventional pollutants.

Testing indicates that mercury from bituminous-fired units tends to speciate as ionic Hg^{2+} if sufficient chlorine is available in the flue gas (primarily $HgCl_2$). The tendency to form ionic mercury is associated with the higher concentration of chlorine typically found in bituminous coals. Emission testing conducted on existing bituminous-fired units suggests that FGD control systems can effectively remove the ionic mercury in the flue gas.

BREC recently conducted systemwide mercury emissions tests on each of its generating units except Reid. Table 3-14 provides a summary of the mercury emission test results.

Table 3-14
Summary of Mercury Tests Results

Mercury (Hg) 1.2 lb/TBtu or 0.0096 lb/GWh	Green 1	Green 2	HMP&L 1	HMP&L 2	Coleman	Wilson	Reid 1*
Total (lb/TBtu)	3.09	2.58	0.62	0.47	3.52	1.77	6.49
Elemental (lb/TBtu)	0.36	0.12	0.28	0.24	0.85	1.56	N/A
Oxidized (lb/TBtu)	2.73	2.46	0.34	0.22	2.67	0.21	N/A

* Stack test results provided by BREC from previous 9/19/06 test reported the mercury concentration in the flue gas ($\mu g/m^3$). For consistency, mercury concentrations in this table were converted to lb/TBtu emission rates using a

[15] See, e.g., "Control of Mercury Emissions From Coal-Fired Electric Utility Boilers," U.S. Environmental Protection Agency, Office of Research and Development, Air Pollution Prevention and Control Division, Research Triangle Park, NC.

fuel F-Factor of 1,800 scf CO_2/MMBtu, a stack gas moisture content of 12%, and a CO_2 concentration in the stack of 10.1% on a wet basis.

Mercury emissions from the BREC generating units vary significantly. Based on a review of the available stack test data, it appears that mercury emissions from the BREC units are a function of the air pollution control systems in place on each unit. For example, at the Sebree Station, mercury emissions from Reid Unit R01 (ESP) were approximately 6.5 lb/TBtu, while mercury emissions from Green Units G01 and G02 (ESP+FGD) averaged 2.8 lb/MMBtu, approximately 80% less than mercury emissions from Unit R01. Mercury emissions from HMP&L Units H01 and H02 (SCR+ESP+FGD), are even lower, averaging approximately 0.55 lb/TBtu, or almost 91% below the Unit R01 emission rate. Similarly, mercury emissions from the Coleman units (ESP+FGD) averaged approximately 3.5 lb/TBtu, while mercury emissions from Wilson Unit W01 (SCR+ESP+FGD) have averaged approximately 1.8 lb/TBtu.

These test results suggest that the FGD and SCR control systems are providing mercury removal. The BREC generating units currently equipped with FGD but without SCR (i.e., C01, C02, C03, G01, and G02) have mercury emissions in the range of 2.6 to 3.5 lb/TBtu, compared to emissions of 6.5 lb/TBtu from Unit R01 (ESP-only). The FGD control systems are likely capturing ionic mercury in the flue gas, primarily $HgCl_2$, and providing an additional 40-60% removal. Elemental mercury re-emission can be an issue in FGD control systems. Ionic mercury captured in the scrubber may be reemitted as elemental mercury, limiting the overall effectiveness of the control system. The three units equipped with SCR (Units H01, H02, and W01) currently achieve the lowest Hg emission rates. These results suggest that the SCRs promote mercury oxidation and removal in the FGD.

Table 3-15 compares existing mercury emissions from each unit to the proposed Utility MACT mercury emission limit.

Table 3-15
Existing Mercury Emissions vs. Proposed Utility MACT Limit

BREC Unit	Baseline Hg Emission Rate (lb/TBtu)	Proposed Utility MACT Emission Limit (lb/TBtu)	Reduction Needed (%)
Coleman Unit C01	3.52	1.2	66%
Coleman Unit C02	3.52	1.2	66%
Coleman Unit C03	3.52	1.2	66%
Wilson Unit W01	1.77	1.2	32%
Green Unit G01	3.09	1.2	61%
Green Unit G02	2.58	1.2	53%
HMP&L Unit H01	0.62	1.2	N/A
HMP&L Unit H02	0.47	1.2	N/A
Reid Unit R01	6.5	1.2	82%

Mercury emissions from Units H01 and H02 are currently below the proposed mercury emission limit of 1.2 lb/TBtu, while mercury emissions from Units C01, C02, C03, W01, G01, G02, and R01 exceed the proposed limit. Therefore, control technologies capable of enhancing mercury oxidation and mercury capture in the units that are not currently equipped with SCR or meeting the proposed MACT limits will be evaluated during the next phase of this study. Technologies available to reduce mercury emissions include, but are not necessarily limited to;

- Halogenated/non-halogenated carbon injection
- Fuel additives
- FGD system mercury re-emission prevention additives
- Fabric Filters

As an alternative to meeting the Hg emission limits on an EGU-specific basis, the Proposed Utility MACT allows emissions averaging at facilities with more than one EGU. To average emissions from more than one unit, the EGUs must be in the same subcategory and be located at one or more contiguous properties which are under common control of the same entity. Thus, emissions averaging will be available at the Sebree and Coleman generating stations. Under this approach, compliance can be demonstrated if the averaged emissions for such EGUs, calculated as a heat input weighted average, are equal to or less than the applicable emission limit.

3.3.5.2 **Acid Gas Emissions**

The Proposed Utility MACT rule includes acid gas emission limits for existing coal-fired EGUs. For the existing coal-fired ≥ 8,300 Btu/lb subcategory, EPA proposed an HCl emission limit of 0.002 lb/MMBtu (30-day average).[16] As an alternative, for existing units equipped with an FGD control system, EPA proposed an SO_2 emission limit of 0.20 lb/MMBtu (30-day average) as a surrogate for the acid gas emissions. Existing coal-fired units equipped with an FGD control system can choose to demonstrate compliance with the Utility MACT acid gas requirement by demonstrating compliance with either the HCl or SO_2 emission limits.

Emissions data generated as part of EPA's 2010 ICR indicate that most existing bituminous-fired units equipped with an FGD control system achieve very low acid gas emissions. The ICR database includes HCl test results for approximately 128 existing bituminous-fired conventional boilers. HCl emissions from all bituminous-fired conventional boilers in the ICR database averaged approximately 0.011 lb/MMBtu, while HCl emissions from bituminous-fired units equipped with an FGD control system averaged approximately 0.0032 lb/MMBtu.[17] Using fuel data included in the ICR database, a controlled HCl emission rate of 0.0032 lb/MMBtu represent an overall HCl removal efficiency of approximately 95% (based on

[16] The MACT emission limits proposed by EPA are 30-boiler operating day averages. In other words, block 24-hour emissions measured from the boiler will be averaged over 30-boiler operating days. A boiler operating day means a 24-hour period between midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for the fuel to be combusted the entire 24-hour period.

[17] The average HCl emission rate for all bituminous-fired units in the ICR database were calculated excluding those results that showed an increase in HCl emissions from the fuel chlorine concentration.

an average fuel Cl^- concentration of 800 ppm-dry). It is clear from the ICR data that FGD control systems effectively remove HCl emissions.

HCl emissions were measured at all BREC units except Reid R01 as part of recent emission stack testing and are provided in Table 3-16 along with SO_2 emissions and proposed Utility MACT acid gas emission limits.

Table 3-16
Baseline HCl and SO_2 Emissions vs. Proposed MACT Acid Gas Emission Limits

Unit	Baseline HCl Emission Rate (lb/MMBtu)	Proposed Utility MACT HCl Limit (lb/MMBtu)	Baseline SO2 Emission Rate (lb/MMBtu)	Proposed Utility MACT SO2 Limit (lb/MMBtu)	Basis
Coleman Unit C01	2.36×10^{-4}	2.0×10^{-3}	0.25	0.20	stack test
Coleman Unit C02	2.36×10^{-4}	2.0×10^{-3}	0.25	0.20	stack test
Coleman Unit C03	2.36×10^{-4}	2.0×10^{-3}	0.25	0.20	stack test
Wilson Unit W01	7.39×10^{-5}	2.0×10^{-3}	0.51	0.20	stack test
Green Unit G01	2.81×10^{-4}	2.0×10^{-3}	0.19	0.20	stack test
Green Unit G02	3.34×10^{-4}	2.0×10^{-3}	0.14	0.20	stack test
Reid Unit R01	Not Measured est. 6.8×10^{-2}	2.0×10^{-3}	4.52	0.20	Baseline HCl emissions were estimated based on 1,750 ppm Cl^- in the coal (0.136 lb/MMBtu HCl), and 50% removal in the ESP.
HMP&L Unit H01	1.67×10^{-3}	2.0×10^{-3}	0.35	0.20	stack test
HMP&L Unit H02	1.37×10^{-3}	2.0×10^{-3}	0.42	0.20	stack test

Based on a review of the available HCl emissions data, it appears that HCl emissions from the BREC units equipped with an FGD control system will be below the proposed Utility MACT limit of 2.0×10^{-3} lb/MMBtu. HCl emissions measured at Units C01, C02, C03, W01, G01 and G02 averaged 2.33×10^{-4} lb/MMBtu, significantly below the proposed MACT limit. Emissions from H01 and H02 are also below the proposed Utility MACT limit but are notably higher than Coleman, Green and Wilson Units.

HCl emissions from Reid Unit R01 (ESP-only) will likely be above the proposed MACT limit. Assuming an average fuel chlorine concentration of 1,750 ppm(dry) and a fuel heating value of 13,200 Btu/lb (HHV dry), potential uncontrolled HCl emissions would be in the range of 0.136 lb/MMBtu. Assuming 50% to 80% removal in the boiler, air heater, and ESP, potential HCl emissions from Unit R01 could range between approximately 0.027 lb/MMBtu to as high as 0.068 lb/MMBtu. Additional HCl removal would be needed to reduce emissions from Unit R01 to a controlled rate of 0.002 lb/MMBtu (the proposed Utility MACT limit).

As discussed in the mercury subsection, the Proposed Utility MACT allows emissions averaging at facilities with more than one EGU. Therefore, BREC should have the option of averaging acid gas emissions at the Coleman and Sebree Stations. Table 3-23 shows the annual average heat input weighted HCl emissions rate from the Sebree Generating Station. Using the annual heat inputs and baseline HCl emission rates shown in Table 3-17, average HCl emissions from the Sebree Station would be above the proposed HCl MACT limit. Table 3-18 calculates revised heat input weighted HCl emissions assuming a 50% reduction in existing emissions from Unit R01. Based on the revised HCl emission rate for Unit R01, annual average emissions from the Sebree Station would be below the proposed Utility MACT emission rate.

Table 3-17
Sebree Station – Average Annual HCl Emissions

Unit	Baseline HCl Emission Rate	Baseline Annual Heat Input	Baseline HCl Emissions
	lb/MMBtu	MMBtu	tpy
Reid Unit R01	0.068	2,240,807	76.2
Green Unit G01	0.000281	2,012,835	0.3
Green Unit G02	0.000334	20,347,531	3.4
HMP&L Unit H01	0.000167	12,823,005	1.1
HMP&L Unit H02	0.000137	13,214,893	0.9
Total		50,639,071	81.8
		Average HCl Emission Rate (lb/MMBtu):	**0.00323**

Table 3-18
Sebree Station – Revised Average Annual HCl Emissions*

Unit	Baseline HCl Emission Rate	Baseline Annual Heat Input	Additional HCl Control	Revised HCl Emission Rate	Revised HCl Emissions
	lb/MMBtu	MMBtu	%	lb/TBtu	lb/yr
Reid Unit R01	0.068	2,240,807	50%	0.0034	38.1
Green Unit G01	0.000281	2,012,835	0%	0.0002	0.3
Green Unit G02	0.000334	20,347,531	0%	0.0002	3.4
HMP&L Unit H01	0.000167	12,823,005	0%	0.0003	1.1
HMP&L Unit H02	0.000137	13,214,893	0%	0.0003	0.9
Total		50,639,071			43.8
				Average HCl Emission Rate (lb/MMBtu):	**0.00173**

* Note: The proposed MACT emission limits are based on 30 boiler operating day averages. If BREC were to consider emissions averaging as a compliance option for the Sebree or Coleman Stations, stationwide emissions must be evaluated on a 30-day average under various operating scenarios.

BREC will have the option of complying with the acid gas MACT standard by demonstrating compliance with the HCl or SO_2 emissions limit. If BREC chooses to demonstrate compliance with the SO_2 emission limit (0.20 lb/MMBtu 30-day average), continuous compliance with the SO_2 limit would be demonstrated using the SO_2 CEMS. The SO_2 option is available only on units equipped with an FGD control system. If BREC chooses to demonstrate compliance with the HCl emission limit rather than the SO_2 limit, continuous compliance would be demonstrated using an HCl CEMS, or BREC may implement an on-going stack testing program.

Existing coal-fired EGUs that elect to demonstrate compliance with the SO_2 limit, and use SO_2 CEMS to demonstrate continuous compliance, are not required to conduct an initial compliance stack test. Instead, the first 30 days of SO_2 CEMS data would be used to determine initial compliance. Similarly, for units that elect to use HCl CEMS to demonstrate continuous compliance with the HCl limit, an initial stack test for HCl would not be required. Instead, the first 30 days of HCl CEMS data would be used to determine initial compliance. Units without SO_2 or HCl CEMS, but with SO_2 emissions control devices, would be required to conduct an initial HCl compliance test, and conduct testing at least every 2 months using EPA Method 26 or 26A to demonstrate continuous compliance with the HCl emission limit. Units without HCl CEMS and without SO_2 or HCl emissions control devices, would be required to conduct an initial HCl compliance test, and conduct emissions stack testing every month to demonstrate continuous compliance with the HCl limit.

Based on stack test data available from the BREC generating units, and taking into consideration stack test data from similar sources available in the ICR database, it appears that the BREC coal-fired units equipped with an FGD control system will meet the proposed Utility MACT HCl emission limit. HCl emissions measured at Units C01, C02, C03, W01, G01 and G02 averaged 2.33×10^{-4} lb/MMBtu, significantly below the proposed HCl limit of 0.002 lb/MMBtu. On the FGD-equipped units BREC will have the option of complying with the SO_2 surrogate limit or the HCl emission limit, and will have the option of demonstrating continuous compliance using the SO_2 CEMS, installing an HCl CEMS, or conducting on-going stack testing. Acid gas emissions from Unit R01 have not been tested, but are likely above the proposed HCl emission limit.

The next phase of this project will include an evaluation of operational measures and air pollution control technologies capable of reducing acid gas emissions from Unit R01. Acid gas control technologies that may be available include, but are not necessarily limited to:

- Dry sorbent injection (Trona, sodium bicarbonate, and hydrated lime)
- Upgrades to the existing ESP's
- Fabric Filters

3.3.5.3 Non-Hg Metallic HAPs

The Proposed Utility MACT rule includes non-mercury trace metal HAP emission limits for existing coal-fired EGUs. For the existing coal-fired ≥ 8,300 Btu/lb subcategory, EPA proposed a total PM (filterable + condensible "TPM") emission limit of 0.030 lb/MMBtu (30-day average) as MACT for the non-Hg metal HAPs. As an alternative to meeting the TPM limit, existing units have the option of meeting a total non-Hg metals emission limit, or complying with individual non-Hg metal emission limits.

(1) **TPM MACT Alternative**

Particulate matter emissions testing was recently conducted at all BREC generating units except Reid. Emissions were tested for TPM, FPM, CPM, total non-Hg HAP metals, and the individual HAP metals. Table 3-19 provides a summary of the PM stack test results.

Table 3-19
Summary of BREC PM Emissions Stack Test Data

BREC Unit	**Particulate Matter Emission Test Results**		
	FPM (lb/MMBtu)	**CPM (lb/MMBtu)**	**TPM (lb/MMBtu)**
Wilson W01	0.0091	0.0104	**0.0196**
Coleman C01	0.0220	0.0178	**0.0398**
Coleman C02	0.0220	0.0178	**0.0398**
Coleman C03	0.0220	0.0178	**0.0398**
Green G01	0.0084	0.0111	**0.0195**
Green G02	0.0046	0.0123	**0.0169**
HMP&L H01	0.0177	0.0142	**0.0319**
HMP&L H02	0.0120	0.0204	**0.0324**
Reid R01	0.2690	not tested	

Based on the stack test results, C01, C02, C03, H01 and H02 all have TPM emissions greater than the proposed Utility MACT limit of 0.030 lb/mmBtu. Currently W01, G01 and G02 meet the proposed limits. However, with the potential addition of control technologies such as Activated Carbon Injection (ACI) for mercury control, it is expected that some of the Units that currently meet the proposed limits may require modifications to handle the additional particulate loading.

Filterable PM emissions will be unit specific, and, in general, will be a function of the effectiveness of the unit's ESP. Stack test data from similar coal-fired units equipped with an ESP suggest that a properly sized and maintained ESP is capable of effectively capturing FPM and achieving very low controlled FPM emission rates. The ICR database includes several FPM test results of less than 0.010 lb/MMBtu from bituminous-fired units equipped with an ESP. FPM emissions data summarized in Table 3-19 suggest that upgrades to the ESP control systems on some of the BREC coal-fired units (except possibly Unit R01) will promote capture of FPM, and achieving controlled FPM emission rates in the range of 0.012 lb/MMBtu or less.

CPM emissions will also be unit specific. In general, CPM consists of inorganic and organic compounds that are emitted in the vapor state and later condense to form aerosol particles. Inorganic species that can contribute to CPM emissions from coal-fired boilers include sulfuric acid mist (SAM), ammonium bisulfate, other acid gases, and trace volatile metals. Organic species in the flue gas can also exist as vapors at stack temperatures and condense to liquid or solid aerosols at ambient temperatures; however, condensible organics from coal-fired boilers are typically very low.

SAM is the most widely recognized form of CPM emitted by coal-fired combustion sources. In a coal-fired boiler, a fraction of the SO_2 in the flue gas will oxidize to sulfur trioxide (SO_3) during the combustion process, and an additional 1.0 – 2.5% can oxidize to SO_3 in the presence of the SCR catalyst (depending on the activity of the catalyst and number of catalyst layers). Sulfur trioxide formed in the boiler and subsequent emission control systems can react with water in the flue gas to form SAM, especially on units firing a higher sulfur bituminous coal and equipped with SCR. Operating experience at pulverized coal-fired units firing an eastern bituminous coal has shown that the installation of an SCR can significantly increase SAM and CPM emissions.

With the exception of R01, CPM emissions from all BREC Units averaged 0.0144 lb/mmBtu and accounted for approximately 56% of the TPM emissions. CPM emissions from all bituminous-fired units included in the ICR study averaged 0.022 lb/MMBtu, and accounted for approximately 54% of the TPM emissions from bituminous-fired units that were not equipped with an SCR control system.

Based on a review of the BREC FPM emissions data, and taking into consideration stack test data available from similar sources, it appears that TPM emissions from Coleman and HMP&L will be above the proposed MACT limits without modifications to increase ESP efficiency. TPM emissions from Wilson and Green appear to be below the proposed MACT limit. FPM emissions from the Wilson and Green Units have averaged less than 0.010 lb/MMBtu whereas HMP&L and Coleman average greater than 0.015 lb/mmBtu.

FPM emissions from Unit R01 were measured at levels significantly above the proposed MACT limit; therefore, it is likely that major modifications will be needed to reduce FPM emissions from Unit R01. As with Hg and HCl, emissions averaging would be available for the Sebree and Coleman Stations to demonstrate compliance with the proposed MACT limits.

(2) **Non-Hg Trace Metal Alternatives**

As an alternative to demonstrating compliance with the TPM emission limit, BREC can choose to demonstrate compliance with the total non-Hg metal emission limit, or the individual non-Hg metal emission limits. The total non-Hg metal limit, and the individual non-Hg metal emission limits, included in the Proposed Utility MACT are summarized along with the recent stack emission test data in Table 3-20.

Table 3-20
Proposed MACT Total non-Hg, and Individual non-Hg Metal Emission Limits vs. Actual Emissions

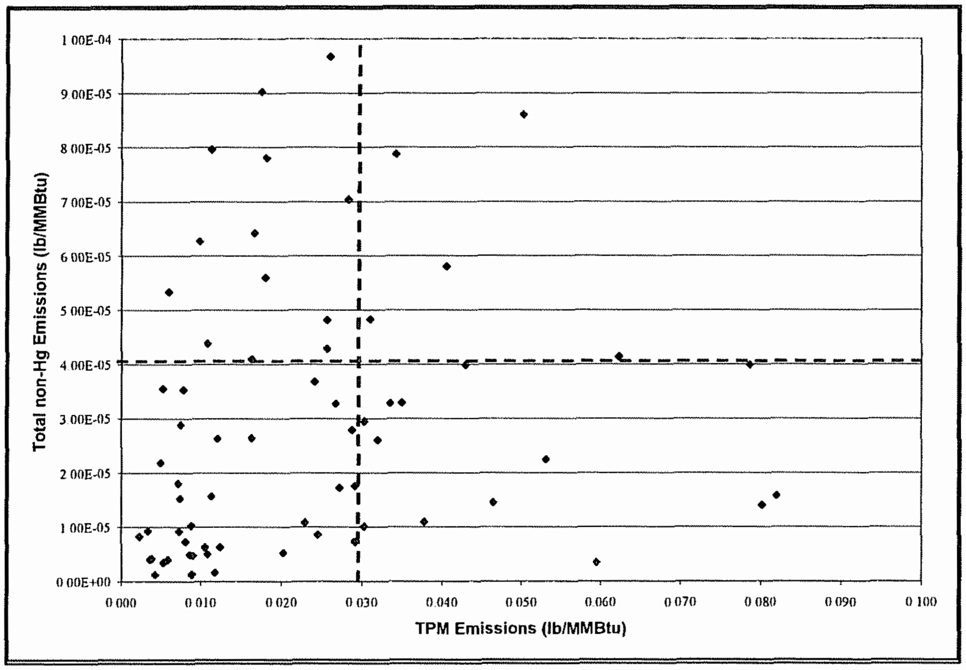
Proposed MACT Emission Limits		Green 1	Green 2	HMP&L 1	HMP&L 2	Coleman	Wilson - Coal
		Stack Emission Test Data*					
Total non-Hg HAP metals	**0.000040 lb/MMBtu**	0.0000906	0.0000678	0.0000959	0.0001203	0.0000910	0.0000591
OR	**OR**						
Individual HAP metals:							
Antimony (Sb)	**0.60 lb/TBtu**	2.900E-07	3.820E-07	7.670E-07	8.900E-07	1.520E-06	3.050E-07
Arsenic (As)	**2.0 lb/TBtu**	4.960E-06	2.890E-06	7.830E-06	6.280E-06	5.000E-06	3.280E-06
Beryllium (Be)	**0.20 lb/TBtu**	5.610E-08	4.470E-08	2.350E-07	3.430E-07	1.700E-07	2.240E-08
Cadmium (Cd)	**0.30 lb/TBtu**	3.230E-07	3.290E-07	1.480E-06	1.950E-06	5.760E-07	4.160E-07
Chromium (Cr)	**3.0 lb/TBtu**	3.640E-05	2.790E-06	2.050E-05	3.040E-05	5.190E-06	5.440E-06
Cobalt (Co)	**0.80 lb/TBtu**	2.110E-07	1.620E-07	7.460E-07	1.300E-06	5.000E-07	2.020E-07
Lead (Pb)	**2.0 lb/TBtu**	2.700E-06	1.880E-06	2.950E-06	4.260E-06	2.050E-06	8.130E-06
Manganese (Mn)	**5.0 lb/TBtu**	7.000E-06	5.050E-06	1.020E-05	1.250E-05	6.220E-06	5.310E-06
Nickel (Ni)	**4.0 lb/TBtu**	4.060E-06	3.150E-06	1.180E-05	2.860E-05	6.720E-06	4.780E-06
Selenium (Se)	**6.0 lb/TBtu**	3.460E-05	5.110E-05	3.940E-05	3.380E-05	6.310E-05	3.120E-05

* All test data is in lb/MMBtu unless noted otherwise.

Based on the stack test results, all BREC Units have total non-Hg HAP metal emissions greater than the proposed Utility MACT limit of 0.000040 lb/mmBtu. Furthermore, with the exception of G02, all BREC units have a majority of the individual HAP metals above their respective proposed MACT limits. Although, Units such as G02 and W01 are relatively close to the proposed limit.

The ICR database includes trace metal and PM emissions test data from 107 bituminous-fired units. Of the 107 units tested, 69 had TPM emissions below the proposed MACT limit of 0.03 lb/MMBtu. Of the units that tested below the TPM MACT limit, 40 (58%) also had total non-Hg metal emissions below the proposed MACT limit of 4.0×10^{-5} lb/MMBtu. Conversely, only 34% (13 of 38) of the units with TPM emissions greater than 0.030 lb/MMBtu had total non-Hg metal emissions below the 4.0×10^{-5} lb/MMBtu limit. Figure 3-8 provides a summary of the TPM and trace metal emissions data from bituminous-fired units in the ICR database.

Figure 3-8
ICR Total Particulate Matter and Total non-Hg Metals Emissions Data



Contrary to to the ICR test results for G01, recent stack emissions data show that none of the BREC units are currently meeting the proposed Utility MACT limit for total or individual non-Hg metals. Choosing to comply with the total or individual non-Hg options could present significant compliance risk because of the limited amount of emissions data and the inability to control specific trace metals. Furthermore, if BREC chooses to comply with the total non-Hg metals or individual non-Hg metals alternatives (rather than the TPM option), demonstrating continuous compliance will likely be more onerous. Coal-fired units that elect to comply with the TPM emission limit, would conduct HAP metals and TPM emissions testing during the same compliance test period initially and every 5 years using EPA Methods 29, 5, and 202. Continuous compliance would be determined using a PM CEMS with an operating limit established based on the FPM values measured during the initial compliance test. Units that elect to comply with the total non-Hg HAP metals emission limit or the individual non-Hg HAP metal emission limits, would be required to conduct TPM and HAP metals testing during the same compliance test period initially and at least once every 5 years, and conduct total or individual non-Hg HAP metals emissions testing every 2 months (or every month if the unit has no PM control device) using EPA Method 29 to demonstrated continuous compliance.

3.3.5.4 Non-Hg Trace Metal MACT Conclusions

Based on the recent stack emission test data from the BREC coal-fired units quantifying FPM and CPM emissions, and non-Hg HAP metals emissions, it appears that TPM emissions from W01, G01 and G02 will be below and C01, C02, C03, H01 and H02 will be above the proposed Utility MACT limit of 0.030 lb/mmBtu. Additionally, based on a previously conducted stack test, TPM emissions from Unit R01 appear to be significantly above the proposed MACT limit. (0.269 vs. 0.030 lb/MMBtu)

Based on recent stack emissions tests, it appears that total non-Hg metals from the BREC units will be above the proposed MACT limit of 4.0×10^{-5} lb/MMBtu and that all BREC units are above compliance levels for at least three of the individual non-Hg metals proposed MACT requirements. Despite units such as G02 and W01 being relatively close to the allowable proposed MACT limits, choosing to comply with the non-Hg metal alternative presents significant risk because of the lack of controllability for certain trace metals.

Because controlled TPM emissions may exceed the proposed MACT standard, the next phase of this project will evaluate control technologies, modifications, and operational measures to further reduce TPM emissions from all the units (both FPM and CPM), focusing on CPM emissions from the units equipped with SCR. Technologies available to reduce FPM emissions include, but are not necessarily limited to;

- Dry sorbent injection (Trona, sodium bicarbonate, and hydrated lime)
- Low oxidation SCR catalysts
- Upgrades to ESP's including advanced discharge electrodes and high frequency Transformer/Rectifiers (T/R)
- Fabric Filters

3.3.5.5 **Utility MACT Summary**

The Proposed Utility MACT rule includes emission limits for mercury, acid gases (HCl or SO_2), and trace metal HAP emissions (TPM, total non-Hg metals, or individual non-Hg metals). Based on the HAP emissions data available from the BREC coal-fired units, and taking into consideration ICR emissions data from similar sources, it is foreseen that modifications are required throughout the BREC fleet to meet the proposed Utility MACT emission limits. Tables 3-21 thru 3-23 compare existing emissions from each unit to the proposed emission limits, and identify the emission reductions that may be needed to comply with the proposed MACT standards.

Table 3-21
Comparison of Baseline Hg Emissions to the Proposed MACT Hg Emission Limit

BREC Unit	Hg		
	Baseline (lb/TBtu)	Proposed MACT (lb/TBtu)	Emission Reduction Requirements
Coleman Unit C01	3.5	1.2	Evaluate technologies and operating measures capable of increasing mercury oxidation and capture in the ESP and FGD, as well as strategies to reduce mercury re-emissions in the FGD.
Coleman Unit C02			
Coleman Unit C03			
Wilson Unit W01	1.77	1.2	Evaluate technologies and operating measures capable of increasing mercury oxidation and capture in the ESP and FGD, as well as strategies to reduce mercury re-emissions in the FGD.
Green Unit G01	3.1	1.2	Evaluate technologies and operating measures capable of increasing mercury oxidation and capture in the ESP and FGD, as well as strategies to reduce mercury re-emissions in the FGD.
Green Unit G02	2.6	1.2	
HMP&L Unit H01	0.62	1.2	Existing Hg emissions are below the proposed MACT limit.
HMP&L Unit H02	0.47	1.2	
Reid Unit R01	6.5 (one test)	1.2	Evaluate technologies and operating measures capable of promoting Hg capture in the ESP.

Table 3-22
Comparison of Baseline Acid Gas Emissions to the Proposed MACT Acid Gas Limits

BREC Unit	Acid Gas Emissions				
	HCl (lb/MMBtu)		SO_2 (lb/MMBtu)		Emission Reduction Requirements
	Baseline	MACT	Baseline	MACT	
Coleman Unit C01	2.36×10^{-4}	2.0×10^{-3}	0.25	0.20	Evaluate FGD modifications, upgrades, and operational measures to achieve controlled SO_2 emissions below 0.20 lb/MMBtu (30-day average). Alternatively, evaluate the feasibility of demonstrating compliance with an HCl CEMS
Coleman Unit C02					
Coleman Unit C03					
Wilson Unit W01	7.39×10^{-5}	2.0×10^{-3}	0.51	0.20	
Green Unit G01	2.81×10^{-4}	2.0×10^{-3}	0.19	0.20	It appears that Green Units G01 and G02 will meet the proposed MACT HCl emission rate of 2.0×10^{-3} lb/MMBtu and the SO_2 surrogate emission rate of 0.20 lb/MMBtu (30-day average)
Green Unit G02	3.34×10^{-4}	2.0×10^{-3}	0.14	0.20	
HMP&L Unit H01	1.67×10^{-3}	2.0×10^{-3}	0.35	0.20	Evaluate FGD modifications, upgrades, and operational measures to achieve controlled SO_2 emissions below 0.20 lb/MMBtu (30-day average). Alternatively, evaluate the feasibility of demonstrating compliance with an HCl CEMS
HMP&L Unit H02	1.37×10^{-3}	2.0×10^{-3}	0.42	0.20	
Reid Unit R01*	6.8×10^{-2}	2.0×10^{-3}	4.52	0.20	Evaluate control technologies capable of reducing SO_2 and acid gas emissions, and the feasibility of demonstrating compliance with an HCl CEMS. Potential technologies include FGD and DSI control systems.

* Baseline HCl emissions summarized above represent estimated emission rates based on limited available stack test data. Additional stack test data would be needed to more accurately predict HCl emissions from each unit (see, subsection 3.4.5.2).

Table 3-23
Comparison of Baseline TPM Emissions to the Proposed MACT TPM Emission Limit

BREC Unit	Total PM Emissions		
	Baseline (lb/MMBtu)	**Proposed MACT (lb/MMBtu)**	**Emission Reduction Requirements**
Coleman Unit C01 Coleman Unit C02 Coleman Unit C03	0.0398	0.030	Technologies capable of reducing CPM and FPM will be evaluated, including DSI and ESP upgrades.
Wilson Unit W01	0.0196	0.030	TMP emissions are below the proposed MACT limit; however, FPM upgrades will be evaluated to account for additional loading imposed by potential ACI and DSI upgrades.
Green Unit G01	0.0195	0.030	TMP emissions are below the proposed MACT limit; however, FPM upgrades will be evaluated to account for additional loading imposed by potential ACI and DSI upgrades.
Green Unit G02	0.0169	0.030	
HMP&L Unit H01	0.0319	0.030	TPM emissions are above the proposed MACT limit, primarily due to acid gas emissions associated with SO_2 to SO_3 oxidation across the SCR. Potential CPM control technologies include low-oxidation catalyst, DSI, and Wet ESP.
HMP&L Unit H02	0.0324	0.030	
Reid Unit R01*	>0.030	0.030	Existing TPM emissions are expected to exceed the proposed MACT limit (based on the results of one FPM stack test). Technologies capable of reducing FPM emissions will be evaluated, including ESP upgrades.

* Reid baseline TPM emissions above represent estimated emission rates based on a limited number of stack tests measuring both FPM and CPM. Additional stack test data would be needed to more accurately predict CPM and TPM emissions (see, subsection 3.4.5.3).

3.4 Regional Haze Rule

On July 6, 2005, the U.S. Environmental Protection Agency (EPA) published the final "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology Determinations" (the "Regional Haze Rule" 70 FR 39104). EPA issued the Regional Haze Rule under the authority and requirements of sections 169A and 169B of the Clean Air Act (CAA). Sections 169A and 169B require EPA to address regional haze visibility impairment in 156 federally-protected parks and wilderness areas (Class I Areas).

As mandated by the CAA, the Regional Haze Rule required that states develop programs to assure reasonable progress toward meeting the national goal of preventing any future, and remedying any existing, impairment of visibility in Class I Areas. The rule required each state to submit a plan to implement the regional haze requirements no later than December 17, 2007. Among other things, the rule required certain stationary sources found to cause or contribute to impairment of visibility in a Class I Area to control emissions using the Best Available Retrofit Technology (BART). To address the requirements for BART, each state was required to:

- Identify all BART-eligible sources within the state.
- Determine whether each BART-eligible source emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in a Class I Area. BART-eligible sources which may reasonably be anticipated to cause or contribute to visibility impairment are classified as BART-applicable sources.
- Require each BART-applicable source to identify, install, operate, and maintain BART controls.

BART-eligible sources include those sources that:

- have the potential to emit 250 tons or more of a visibility-impairing air pollutant;
- were in existence on August 7, 1977 but not in operation prior to August 7, 1962; and
- whose operations fall within one or more of the specifically listed source categories in 40 CFR 51.301 (including fossil-fuel fired steam electric plants of more than 250 mmBtu/hr heat input and fossil-fuel boilers of more than 250 mmBtu/hr heat input).

As an alternative to the source-specific BART requirements, EPA presented refined ambient air quality impact analyses in the Regional Haze Rule demonstrating that emission reductions anticipated with the Clean Air Interstate Rule (CAIR) would provide for greater progress toward remedying visibility impairment than BART. Based on these analyses, EPA concluded that states that opt to participate in the CAIR cap-and-trade programs need not require affected BART-eligible EGUs to install, operate, and maintain BART. In other words, states that comply with CAIR by subjecting EGUs to the EPA administered cap-and-trade program (discussed in section 3.1) could consider BART satisfied for NOx and SO_2 from the BART-eligible EGUs.

In June 2008, the Kentucky Department of Environmental Protection-Division of Air Quality (DAQ) submitted the final Kentucky Regional Haze SIP to EPA for review and approval as required by §169A of the Clean Air Act (the "Regional Haze SIP"). The June 2008 Regional Haze SIP was based on EPA's conclusion that CAIR would provide greater reasonable progress toward visibility improvement in the Class I Areas than source-specific BART determinations. In May 2010, DAQ submitted to EPA a formal Regional Haze SIP revision on two technical issues (neither of which affected the BREC BART-eligible units). The June 2008 and May 2010 SIP packages remain under review by EPA.

3.5 The Kentucky Regional Haze SIP addresses visibility impairing emissions from the BREC generating units based on EPA's conclusion that CAIR would provide greater reasonable progress toward visibility improvement than source-specific BART, and requires the BREC units to comply with the applicable CAIR requirements. Although EPA has not yet issued final approval of the Kentucky Regional Haze SIP, it is expected that states, such as Kentucky, that opt to participate in the CAIR cap-and-trade programs (and most likely the CSAPR cap-and-trade programs) need not require affected BART-eligible sources to install BART. The applicable CAIR requirements are discussed in detail in Section 3.1 of this report, and the CSAPR requirements are discussed in Section 3.3. We think that it is unlikely that the Kentucky Regional Haze SIP will require emission reductions (NOx and SO2) from the BREC units beyond those required by CAIR and the CSAPR.

National Ambient Air Quality Standards

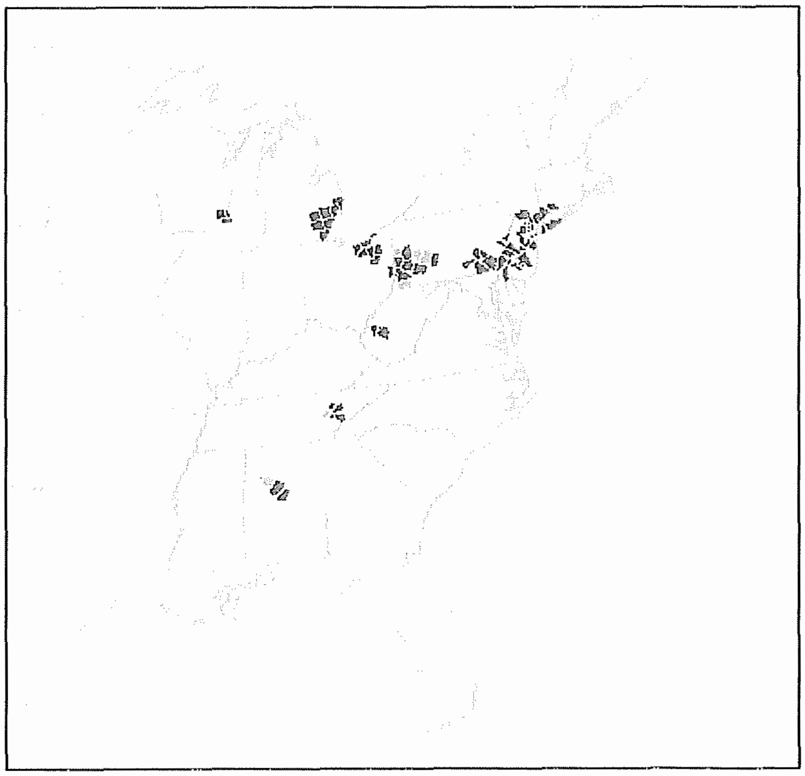
EPA has recently proposed and/or finalized several NAAQS revisions. The NAAQS revisions will likely increase the number of nonattainment areas in the U.S., and may trigger the need for more stringent air pollution controls. The following sections highlight NAAQS revisions that could affect operations at the BREC Generating Stations.

3.5.1 PM2.5 NAAQS

In 1997 EPA revised the NAAQS for PM to add new standards for fine particles, using $PM_{2.5}$ as the indicator. EPA established primary annual and 24-hour ambient air quality standards for $PM_{2.5}$ of 15 $\mu g/m^3$ and 65 $\mu g/m^3$, respectively. On October 17, 2006, EPA revised the primary and secondary NAAQS for $PM_{2.5}$. In that rulemaking, EPA reduced the 24-hour NAAQS for $PM_{2.5}$ to 35 $\mu g/m^3$ and retained the existing annual $PM_{2.5}$ NAAQS of 15 $\mu g/m^3$.

In October 2009, EPA issued final area designations for the 24-hour $PM_{2.5}$ NAAQS. Figure 3-9 shows the location of the $PM_{2.5}$ nonattainment areas in the eastern half of the U.S. All areas of Kentucky, including Hancock, Ohio, and Webster Counties, were designated as unclassifiable/attainment with the 24-hour $PM_{2.5}$ NAAQS.

Figure 3-9
$PM_{2.5}$ Nonattainment Areas



On February 24, 2009, the U.S. Court of Appeals for the District of Columbia issued rulings on litigation involving the 2006 $PM_{2.5}$ NAAQS.[18] Among other things, the Court remanded the annual primary $PM_{2.5}$ standard of 15 $\mu g/m^3$ to EPA because the agency failed to explain adequately why this level is "requisite to protect the public health." In response to the Court's decision, EPA is considering lowering the annual $PM_{2.5}$ NAAQS to 12 - 14 $\mu g/m^3$. EPA is expected to issue a Notice of Proposed Rulemaking (NPRM) revising the $PM_{2.5}$ NAAQS in mid-2011.

If EPA proposes a more stringent annual standard, Kentucky will be required to re-elevate the attainment status of areas within the state. If the more stringent standard becomes final, it is possible that some areas in Kentucky, including the Cincinnati-Middleton OH-KY-IN, Clarksville TN-KY, Huntington-Ashland, Louisville, and Paducah-Mayfield areas, will be designated as nonattainment areas with respect to the revised standard. If the more stringent standard results in additional counties being designated nonattainment, Kentucky would be required to modify its State Implementation Plan (SIP) and could require additional reductions of primary $PM_{2.5}$ as well as NOx and SO_2 as precursors to the formation of secondary $PM_{2.5}$. However, until EPA revises the NAAQS, and Kentucky revises its SIP, there is no way to accurately predict the emission reductions that may be required.

At this time, EPA has not proposed modifying the $PM_{2.5}$ NAAQS, and there are no $PM_{2.5}$ NAAQS regulatory drivers that would compel Kentucky to impose additional emission reductions beyond those proposed in the CSAPR. If EPA were to revise the $PM_{2.5}$ NAAQS, a potential timeline could be as follows: (1) EPA issues the NPRM mid-2011; (2) EPA publishes a final rule in mid-2012; (3) EPA issues final area designations by the end of 2013; (4) EPA approves Kentucky's final SIP in 2015; and (5) emission controls on affected units would have to be in place in the 2018 timeframe.

3.5.2 **Ozone NAAQS**

In 2008, EPA reduced the 8-hour ozone NAAQS from 80 to 75 ppb. EPA and the States continue to implement the new standard, and final area designations are expected to be published in 2011. In a letter dated March 12, 2009 from Kentucky to U.S.EPA Region 4, the state provided its recommendations for designation of areas within the state with respect to the 2008 8-hour ozone NAAQS. In that letter, Kentucky proposed designating several counties within the state, including Daviess, Kenton, **Hancock**, Henderson, Greenup, Jefferson, Hardin, Christian, and Simpson counties, as nonattainment with the 2008 8-hour ozone NAAQS. All other areas of Kentucky, including Ohio, and Webster Counties, would be classified as attainment or unclassifiable with respect to the NAAQS. Although Kentucky proposed to designate Webster County as unclassifiable with respect to the 8-hour ozone NAAQS, in the March 12, 1999 letter Kentucky noted that the 3-year average (2006-2008) of the annual 98^{th} percentile of the 8-hour average ozone concentration measured at the Henderson County monitor (located adjacent North of Webster County) was 77 ppb, which does not achieve the 8-hour NAAQS.

On January 19, 2010, EPA proposed lowering the 8-hour ozone standard even further to 60 - 70 ppb. A lower 8-hour ozone standard would be expected to result in more nonattainment areas, and would require Kentucky to re-evaluate the attainment status of areas within the state. If additional areas within the state are designated as nonattainment areas, the Kentucky SIP could require

[18] *American Farm Bureau vs. EPA*, No. 06-1410 (D.C. Cir. Feb. 24, 2009).

additional NOx reductions from existing stationary sources. EPA intends to complete reconsideration of the 8-hour ozone NAAQS by the end of July 2011.

3.5.3 NO2 NAAQS

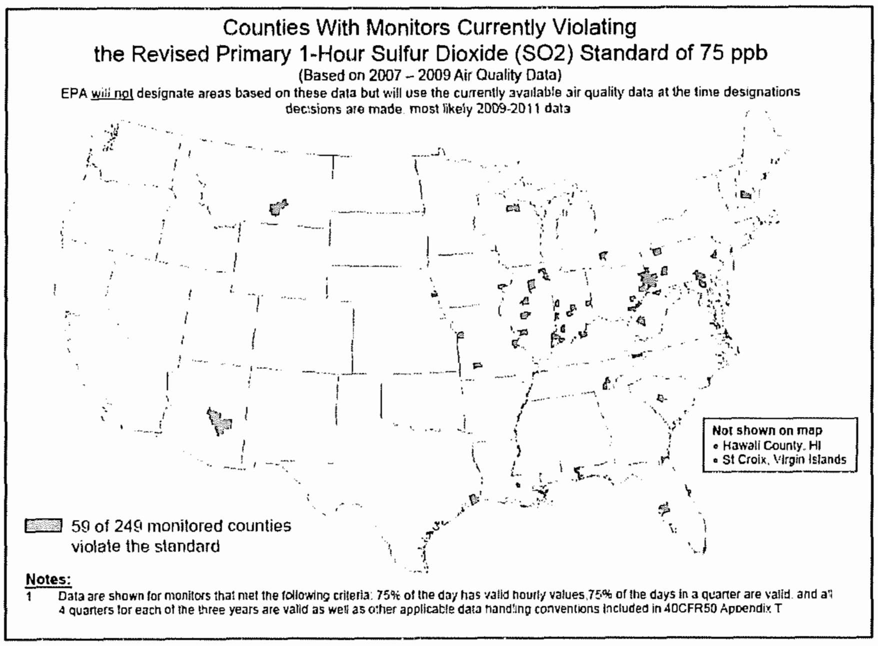
On February 9, 2010, EPA published its final NO_2 NAAQS rule, setting a new 1-hour NO_2 standard of 100 ppb, and retaining the current annual NO_2 standard of 53 ppb. The effective date of the new standard was April 12, 2010. All areas of Kentucky are currently in attainment with the annual NO_2 NAAQS; however, the State will be required to designate areas as attainment or nonattainment with the new 1-hour standard. EPA expects to designate areas as attainment or nonattainment by January 2012 based on the existing community-wide ambient air quality monitoring network. In the event areas within Kentucky are designated nonattainment, the State would be required to modify its SIP and could require additional NOx controls. If EPA designates areas of Kentucky as nonattainment, EPA would be expected to approve the final Kentucky SIP in the 2015 to 2016 timeframe, and could require control technologies to be installed in the 2018 timeframe.

3.5.4 SO2 NAAQS

On June 2, 2010 EPA published a final revision to the NAAQS for SO_2. In the final rule EPA revised the primary SO_2 standard by establishing a new 1-hour ambient air quality standard at a level of 75 ppb. EPA also revoked the two existing primary standards of 140 ppb (24-hours) and 30 ppb (annual) because it was determined that they would not add additional public health protection beyond that provided by the new 1-hour standard.

All areas of Kentucky were in attainment with the 24-hour and annual SO_2 NAAQS; however, Kentucky will be required to re-visit its designations for compliance with the new 1-hour standard. Kentucky's ambient air quality impact monitoring network includes 13 SO_2 monitoring stations, including 1 in the Owensboro Metropolitan Statistical Area (MSA) and 3 in the Louisville-Jefferson County MSA. Ambient SO_2 concentrations measured at the Owensboro MSA monitoring station have been below the 24-hour standard; however, SO_2 concentrations in the Louisville-Jefferson County MSA have been measured above the 1-hour standard. Figure 3-10 is a map published by EPA showing the location of SO_2 ambient air quality monitors that have measured SO_2 concentrations above the 1-hour standard (including the Louisville-Jefferson County MSA).

Figure 3-10
Counties with Monitors Measuring 1-hour SO_2 Ambient Air Concentrations Above the June 2, 2010 Standard



Unlike other NAAQS implementation rules, the 1-hour SO_2 rule requires regulatory agencies to supplement ambient air quality monitoring data with refined dispersion modeling to determine if areas with sources that have the potential to cause or contribute to a violation of the new standard can comply with the standard. On March 24, 2011, EPA issued a guidance memorandum to direct states on the SO_2 designation process and timeline.[19] EPA anticipates using both air quality monitoring data and appropriate air quality impact modeling to identify areas violating the NAAQS, acknowledging that the existing ambient air quality monitoring network may not be adequate to fully characterize ambient concentrations of SO_2, including the maximum ground level concentrations that exist around existing stationary sources. The guidance memorandum directs states to provide initial designations based on the following criteria:

Nonattainment: An area where monitoring data or an appropriate modeling analysis indicate a violation.

Attainment: An area that has no monitored violations and which has an appropriate modeling analysis, if needed, and any other relevant information demonstrating no violations.

[19] Letter from Stephen D. Page to Regional Air Division Directors, Regions I-X, Subject: Area Designations for the 2010 Revised Primary Sulfur Dioxide National Ambient Air Quality Standard, March 24, 2011 (the "1-hour SO_2 NAAQS Guidance Memo").

Unclassifiable (all other areas): An area that has no monitored violations and lacks an appropriate modeling analysis, if needed, or other appropriate information sufficient to support an alternate designation.

In the March 24, 2011 guidance memorandum EPA suggests that states should focus resources to conduct refined dispersion modeling first on the most significant sources of SO_2 emissions, and on those sources that are most likely to contribute to a violation of the 1-hour NAAQS. It is likely that dispersion modeling will identify a number of areas, specifically areas in close proximity to an existing major stationary source of emissions, as exceeding the 1-hour standard.

On June 2, 2011, Kentucky sent a letter to EPA Region 4 with the State's recommendations for the 1-hour SO_2 nonattainment areas. Based on ambient SO_2 monitors in Kentucky, the State calculated the 3-year average of the 99^{th} percentile daily maximum 1-hour concentration and compared the results to the 75 ppb standard. The State recommended designating Jefferson County (i.e., Louisville) as nonattainment for the SO_2 standard, and designating the rest of the areas in Kentucky attainment/unclassifiable.

EPA is required to review these recommendations, and approve, revise, or disapprove of the State's recommendations. Unlike other NAAQS implementation rules, EPA plans to use refined dispersion modeling to determine if areas with sources that have the potential to cause or contribute to a violation of the new standard can comply with the standard. Because both ambient air quality monitoring and refined air dispersion modeling will be used to identify the 1-hour SO_2 nonattainment areas, a number of existing stationary sources have initiated modeling projects to determine the likelihood that dispersion modeling will conclude that emissions from their facility will cause or contribute to an exceedance of the 1-hour SO_2 standard. Preliminary modeling should be conducted using the AERMOD air dispersion model, the model that EPA will use to develop their recommended designations. Modeled ambient air quality impacts will be highly site-specific, and a function of the site topography and terrain, prevailing winds, site meteorological conditions, stack heights, stack temperatures and flow rates, and controlled SO_2 emissions. However, preliminary modeling results from existing sources suggest that SO_2 emissions from coal-fired power plants that are not equipped with FGD, and facilities with relatively short stacks, may have modeled exceedances of the 1-hour SO_2 standard. Facility-specific modeling would be needed to determine if SO_2 emissions from the BREC facilities have the potential to cause or contribute to an exceedance of the 1-hour SO_2 NAAQS.

Although Kentucky has proposed designated all areas of the state (with the exclusion of Jefferson County) as attainment/unclassifiable with respect to the 1-hour SO_2 NAAQS, it is possible that EPA (based on ambient air quality impact modeling) will disagree with Kentucky's recommendations and recommend designating additional areas within the State as nonattainment. EPA intends to complete designations by June 2012 (however this deadline has slipped), and anticipates designating areas based on 2008-2010 ambient air quality monitoring data and refined dispersion modeling results. In the event areas of Kentucky are designated as nonattainment, the State would need to submit its revised SIP in 2014. SIP revisions would describe the actions that Kentucky would take to come into compliance with the new standard, including SO_2 emission reductions from existing stationary sources. EPA would be expected to approve the final Kentucky SIP by the end of 2016, and could require control technologies to be installed in the 2018 – 2019 timeframe. Depending on the location of the nonattainment areas and the severity of nonattainment, the revised SIP could require BREC to upgrade, modify, or replace the existing FGD control systems on the Coleman, Wilson, Green and HMP&L units, and install FGD control on Reid Unit R01, in the 2016-2018 timeframe. However, until EPA finalizes the 1-hour SO_2 nonattainment areas, and Kentucky revises its SIP, there is no way to accurately predict the SO_2 emission reductions that would be required by the SIP.

3.5.5 NAAQS Summary

The new 1-hour NOx and SO_2 ambient air quality standards, and revisions to the $PM_{2.5}$ and ozone standards, could result in more areas being designated as nonattainment areas in Kentucky and other downwind states. If so, Kentucky would be required to revise its SIP to address $PM_{2.5}$, ozone, NO_2, and SO_2 nonattainment. However, until EPA revises the NAAQS and finalizes the nonattainment area designations, and Kentucky revises its SIP, there is no way to accurately predict the emission reductions that would be triggered by the NAAQS revisions. SIP revisions could require additional SO_2 and NOx emission reductions from existing stationary sources in the 2016- 2018 timeframe.

Alternatively, EPA could use the revised NAAQS (and corresponding nonattainment area designations) to modify the CSAPR. Modifications to the CSAPR would likely include reductions in the State's CSAPR budgets, and a corresponding reduction in the number of allowances allocated to each CSAPR affected unit. Potential Phase II CSAPR requirements are discussed in section 3.6 of this report.

3.6 CSAPR Phase II

As discussed in section 3.2, the Cross-State Air Pollution Rule (CSAPR), published in the Federal Register on August 8, 2011, was designed to address emissions from large stationary sources that cause or contribute to ozone and PM2.5 nonattainment in downwind states. EPA used air quality impact modeling to identify emissions contributing to downwind nonattainment, and to determined emission reductions needed to eliminate each states' contribution to downwind nonattainment. As discussed in section 3.5, EPA is considering revising the ozone and PM2.5 NAAQS, and making both ambient air quality standards more stringent. If such revisions are finalized, it is almost certain that more areas in Kentucky, and other downwind states, will be designated as ozone and PM2.5 nonattainment areas. Generally, states are required to modify their SIPs to address nonattainment; however, as an alternative, EPA could use CSAPR to address the revised NAAQS standards.

There is speculation that EPA will propose revisions to CSAPR in one or more phases. Initial changes could be proposed in late 2011 to address the new ozone NAAQS, and additional changes could be proposed in 2012 to address the new PM2.5 NAAQS. For this evaluation, it was assumed that EPA will propose one revision to CSAPR addressing both NAAQS standards ("Phase II CSAPR"), and that the Phase II rule would take effect in the 2016-2018 timeframe.

It is likely that the Phase II CSAPR would address the new ozone and PM2.5 NAAQS standards by reducing each States' CSAPR allocation budget. EPA would conduct ambient air quality impact modeling to identify emissions that contribute to the new nonattainment area designations, and revise the emission budgets to eliminate each States' contribution to downwind nonattainment. Revisions to the State budgets would result in a corresponding reduction in the number of allowances allocated to each unit; however, until EPA finalizes the revised NAAQS, and conducts impact modeling, it is difficult to predict the emission reductions that would be required by Phase II CSAPR.

As discussed in section 3.5, EPA is considering reducing the PM2.5 NAAQS from 15 $\mu g/m^3$ to 12-14 $\mu g/m^3$, and reducing the 8-hour ozone NAAQS from 75 ppb to 60 to 70 ppb. In both cases, EPA is considering reducing the existing NAAQS standard by 7% to 20%. Although refined state-by-state air quality impact modeling would be needed to quantify the emission reductions needed to meet the new NAAQS standards and to establish the new state budgets, this analysis is based on the assumption that the Phase II CSAPR allowance allocations will be 20% below the Phase I allocations. This assumption is based on a review of the baseline contribution modeling prepared by EPA as part of the Phase I CSAPR. In general, baseline contribution modeling for the Phase I rule suggested that a 1% reduction in NOx and SO_2 emissions from all existing EGUs resulted in an average 1% reduction in ozone and PM2.5 ambient air concentrations at all modeled receptors (although the ambient air quality improvements varied significantly depending on source and receptor locations).

Assuming: (1) Phase II CSAPR allowance budgets are 20% below the Phase I budgets; (2) Phase II allowances are allocated using a methodology similar to that used by EPA in its Phase I rule (i.e., based on each units' prorated portion of the states baseline heat input); and (3) baseline heat inputs to the affected CSAPR EGUs remain relatively constant, the projected Kentucky and BREC Phase II CSAPR allowance budgets are summarized in Tables 3-24 and 3-25, respectively.

Table 3-24
Projected Kentucky Phase II CSAPR Emission Budgets (2016/2018)*

Kentucky Phase II CSAPR Allowance Budgets	Annual SO_2 (tons)	Annual NOx (tons)	Ozone Season NOx (tons)
Full Allocations	79,926	59,318	25,094

* Projected Phase II CSAPR allowance budgets were calculated based on 80% of the 2014 CSAPR allowance budgets, not including new unit set-aside budgets.

Table 3-25
Projected BREC Phase II CSAPR Allocations (2016/2018)

BREC Unit	Annual SO_2 Allowances (tpy)	Annual NOx Allowances (tpy)	Ozone Season NOx Allowances (tpy)
Coleman Unit C01	920	673	285
Coleman Unit C02	920	674	288
Coleman Unit C03	981	718	311
Wilson Unit W01	2,891	2,116	944
Green Unit G01	1,571	1,150	493
Green Unit G02	1,417	1,162	498
HMP&L Unit H01	1,001	733	317
HMP&L Unit H02	1,031	755	329
Reid Unit R01	175	128	54
Reid Unit RT	7	5	3
Total	10,914	8,114	3,522

Using the baseline annual and ozone season heat inputs used in the Phase I CSAPR evaluation (section 3.2), and assuming annual and ozone heat inputs to the BREC units remain relatively constant, the controlled SO_2 and NOx emission rates that need to be achieved to match the projected Phase II CSAPR allowance allocations are shown in Table 3-26 thru 3-27.

Table 3-26a
Baseline SO_2 Annual Emissions vs. Projected Phase II CSAPR SO_2 Allocations

BREC Unit	Projected Phase II CSAPR Allocations(1) (tpy)	Annual SO2 Emissions (2006-2010) (tpy)	Allowance Surplus or (Deficit) (tpy)
Coleman Unit C01	920	1,473	(553)
Coleman Unit C02	920	1,473	(553)
Coleman Unit C03	981	1,571	(590)
Wilson Unit W01	2,891	9,438	(6,547)
Green Unit G01	1,571	1,873	(302)
Green Unit G02	1,417	1,414	3
HMP&L Unit H01	1,001	2,227	(1,226)
HMP&L Unit H02	1,031	2,745	(1,714)
Reid Unit R01	175	5,066	(4,891)
Reid Unit RT	7	5	2
Total	10,914	27,285	(16,371)

(1) Projected Phase II CSAPR allocations = 80% of the 2014 CSAPR allocations.

Table 3-26b
Projected BREC Phase II CSAPR Annual SO_2 Allocations and Calculated Allowance Equivalent Emission Rates

BREC Unit	Projected Phase II CSAPR Allocations(1) (tpy)	Annual Heat Input(2) (MMBtu/yr)	Allowance Equivalent Emission Rate (lb/MMBtu)	Actual Annual Emission Rate (lb/MMBtu)	% Reduction
Coleman Unit C01	920	11,784,789	0.156	0.250	38%
Coleman Unit C02	920	11,787,242	0.156	0.250	38%
Coleman Unit C03	981	12,570,106	0.156	0.250	38%
Wilson Unit W01	2,891	37,043,481	0.156	0.510	69%
Green Unit G01	1,571	20,128,359	0.156	0.186	16%
Green Unit G02	1,417	20,347,531	0.139	0.139	0%
HMP&L Unit H01	1,001	12,823,005	0.156	0.347	55%
HMP&L Unit H02	1,031	13,214,893	0.156	0.415	62%
Reid Unit R01	175	2,240,807	0.156	4.522	97%
Reid Unit RT	7	87,379	0.160	0.117	NA
Total	10,914	142,027,592	0.154	0.384	60%

(1) Projected Phase II CSAPR allocations = 80% of the 2014 CSAPR allocations.
(2) Baseline annual heat inputs are calculated as the average of the three highest heat input years for each unit between the years 2006 and 2010

Table 3-27a
Baseline NOx Annual Emissions vs. Projected Phase II CSAPR Annual NOx Allocations

BREC Unit	Projected Phase II CSAPR Annual NOx Allowances(1) (tpy)	Baseline Annual NOx Emissions (tpy)	Allowance Surplus or (Deficit) (tpy)
Coleman Unit C01	673	1,858	(1,185)
Coleman Unit C02	674	1,585	(911)
Coleman Unit C03	718	2,044	(1,326)
Wilson Unit W01	2,116	934	1,182
Green Unit G01	1,150	2,050	(900)
Green Unit G02	1,162	2,168	(1,006)
HMP&L Unit H01	733	460	273
HMP&L Unit H02	755	418	337
Reid Unit R01	128	512	(384)
Reid Unit RT	5	45	(40)
Total	8,114	12,074	(3,960)

(1) Projected Phase II CSAPR allocations = 80% of the 2014 CSAPR allocations.

Table 3-27b
Projected BREC Phase II CSAPR Annual NOx Allocations and Calculated Allowance Equivalent Emission Rates

BREC Unit	Projected Phase II CSAPR Annual NOx Allowances(1) (tpy)	Annual Heat Input(2) (MMBtu/yr)	Allowance Equivalent Emission Rate (lb/MMBtu)	Average Annual Emission Rate (lb/MMBtu)	% Reduction
Coleman Unit C01	673	11,254,853	0.120	0.330	64%
Coleman Unit C02	674	9,544,382	0.141	0.332	58%
Coleman Unit C03	718	12,195,952	0.118	0.335	65%
Wilson Unit W01	2,116	36,221,670	0.117	0.052	NA
Green Unit G01	1,150	19,866,020	0.116	0.206	44%
Green Unit G02	1,162	20,128,970	0.115	0.215	47%
HMP&L Unit H01	733	13,003,466	0.113	0.071	NA
HMP&L Unit H02	755	12,118,692	0.125	0.069	NA
Reid Unit R01	128	1,962,424	0.130	0.522	75%
Reid Unit RT	5	126,361	0.079	0.708	89%
Total	8,114	136,422,791	0.119	0.177	33%

(1) Projected Phase II CSAPR allocations = 80% of the 2014 CSAPR allocations.
(2) For the NOx evaluation, baseline annual heat inputs are equal to 2010 actual annual heat inputs.

Table 3-28a
Baseline NOx Seasonal Emissions vs. Projected Phase II CSAPR Seasonal NOx Allocations

BREC Unit	Projected Phase II CSAPR Ozone Season NOx Allowances[1] (tpy)	Ozone Season NOx Emissions (2010) (tpy)	Allowance Surplus or (Deficit) (tpy)
Coleman Unit C01	285	733	(448)
Coleman Unit C02	288	735	(447)
Coleman Unit C03	311	857	(546)
Wilson Unit W01	944	378	566
Green Unit G01	493	789	(296)
Green Unit G02	498	890	(392)
HMP&L Unit H01	317	208	109
HMP&L Unit H02	329	179	150
Reid Unit R01	54	193	(139)
Reid Unit RT	3	33	(30)
Total	3,522	4,995	(1,473)

(1) Projected Phase II CSAPR allocations = 80% of the 2014 CSAPR allocations.

Table 3-28b
Projected BREC Phase II CSAPR Seasonal NOx Allocations and Calculated Allowance Equivalent Emission Rates

BREC Unit	Projected Phase II CSAPR Ozone Season NOx Allowances[1] (tpy)	Ozone Season Heat Input[1] (MMBtu)	Allowance Equivalent Emission Rate (lb/MMBtu)	Average Annual Emission Rate (lb/MMBtu)	% Reduction
Coleman Unit C01	285	4,413,566	0.129	0.332	61%
Coleman Unit C02	288	4,391,647	0.131	0.335	61%
Coleman Unit C03	311	5,084,415	0.122	0.337	64%
Wilson Unit W01	944	15,229,924	0.124	0.050	NA
Green Unit G01	493	7,820,468	0.126	0.202	38%
Green Unit G02	498	8,411,654	0.118	0.212	44%
HMP&L Unit H01	317	5,589,305	0.113	0.074	NA
HMP&L Unit H02	329	5,369,949	0.123	0.066	NA
Reid Unit R01	54	824,447	0.131	0.467	72%
Reid Unit RT	3	95,540	0.063	0.700	91%
Total	3,522	57,230,917	0.123	0.175	30%

(1) Projected Phase II CSAPR allocations = 80% of the 2014 CSAPR allocations.
(2) For the NOx evaluation, baseline ozone season heat inputs are equal to 2010 actual seasonal heat inputs.

3.6.1 Phase II CSAPR Summary & Conclusions

The 8-hour ozone and PM2.5 NAAQS are the regulatory drivers for the Cross-State Air Pollution Rule (discussed in section 3.3). As discussed in section 3.5, EPA is considering revising the existing 8-hour ozone and PM2.5 NAAQS, making the ambient air quality standards more stringent. If revisions to the NAAQS are finalized, it is almost certain that more areas in Kentucky, and other downwind states, will be designated as ozone and PM2.5 nonattainment areas.

EPA could revise the CSAPR to address the new 8-hour ozone and PM2.5 NAAQS. If so, it is likely that Phase II CSAPR would address the new ozone and PM2.5 NAAQS standards by reducing each States' CSAPR allocation budget. EPA would conduct ambient air quality impact modeling to identify emissions that contribute to the new nonattainment area designations, and revise the emission budgets to eliminate each States' contribution to downwind nonattainment. For this analysis, it was assumed that the Phase II CSAPR allocations will be 20% below the Phase I allocations, and that the Phase II rule will take effect in the 2016-2018 timeframe.

Assuming Phase II CSAPR allocations are 20% below the 2014 CSAPR allocations, the BREC generating stations should receive approximately 10,914 SO_2 allocations in the 2016 – 2018 timeframe. These allocations compare to systemwide baseline SO_2 emissions in the range of 25,757 tpy (average) to 27,286 tpy (average of three highest emissions years). Using the baseline SO_2 emissions and annual unit heat input data summarized in Tables 3-32a and 3-32b, systemwide SO_2 emissions must be reduced by approximately 60% to match the projected Phase II CSAPR SO_2 allowances. Options for reducing systemwide SO_2 emissions to match the projected Phase II Transport Rule allocations include upgrading, modifying, or replacing the existing FGD control systems to provide more aggressive SO_2 removal.

Assuming that the Phase II CSAPR NOx allocations are 20% below the 21012 CSAPR allocations, BREC generating units would receive approximately 8,114 annual NOx allowances (compared to its 2010 annual NOx emissions of 12,074 tons), and approximately 3,522 seasonal NOx allowances (compared to its 2010 seasonal NOx emissions of 4,995 tons). To meet the projected Phase II CSAPR NOx annual and ozone season allocations, systemwide NOx emissions must be reduced by approximately 30 - 33% (based on the emissions and allocation data summarized in Tables 3-27 and 3-28).

NOx emissions from Wilson Unit W01, HMP&L Unit H01, and HMP&L Unit H02 would still be below their respective allocation projections. These units are equipped with SCR and currently achieve controlled NOx emissions in the range of 0.052 to 0.070 lb/MMBtu, and would continue to generate NOx allocations that could be used to offset excess NOx emissions from other units. Assuming a total systemwide annual heat input of 136,400,000 MMBtu, and a total ozone season heat input of 57,200,000 MMBtu, NOx emissions from all BREC units would have to average approximately 0.12 lb/MMBtu to match the projected Phase II CSAPR allocations. A systemwide average emission rate of 0.12 lb/MMBtu is approximately 33% below the current systemwide average NOx emission rate of 0.177 lb/MMBtu.

Options for reducing systemwide NOx emissions to match the projected Phase II CSAPR NOx allocations include combustion modifications to reduce NOx formation in the boiler and post-combustion NOx controls such as selective non-catalytic reduction and SCR.

3.7 Multi-Pollutant Legislative Initiatives

In response to the Court's vacatur of CAIR and CAMR, several legislative initiatives were proposed in the 111th Congress to amend the Clean Air Act and require additional emission reductions from electric utility generating units. The leading legislative approach for replacing CAIR was introduced to the Senate Committee on Environment and Public Works by Senators Carper and Alexander on February 4, 2010. The Carper-Alexander bill would have replaced CAIR and established nationwide caps on SO_2 and NOx emissions from electric generating units.

In general, the CAAA of 2010 would have required utilities to reduce total SO_2 emissions from the 2008 level of 7.6 million tons to 1.5 million tons by 2018 (~80% reduction), and reduce total NOx emissions from the 2008 level of 3.0 million tons to 1.6 million tons by 2018 (~50% reduction). The bill proposed to establish a nationwide cap-and-trade program for SO_2 (similar to the Acid Rain Program), and two NOx trading programs; one for eastern states and one for western states. The bill proposed amending the CAA to include a new Section 418 (Phase III Sulfur Dioxide Requirements), and Section 419 (Nitrogen Oxide Control and Trading Program).

In addition to requiring SO_2 and NOx emission reductions, the CAAA of 2010 would have required Hg reductions. Specifically, the bill included provisions requiring: (1) EPA to regulate HAP emissions from coal and oil-fired EGUs pursuant to §112(d) of the CAA; and (2) EPA's forthcoming MACT standard to require at least 90% reduction of mercury emissions from coal-fired EGUs.

In September 2010, the Senators decided to cancel the Environment and Public Works Committee vote on the bill after failing to reach agreement on several key issues in the bill, including emission reduction requirements, and Congress has not moved forward with multi-pollutant control legislation. It appears unlikely that multi-pollutant control legislation will be taken up by the 112th Congress. We think it is more likely that, for the near future, NOx and SO_2 emissions from existing coal-fired electric generating units will be regulated by the CSAPR, and mercury emissions will be regulated by the Utility MACT.

3.8 Greenhouse Gas Requirements

Unless legal challenges or opposition in Congress strip EPA of it's authority to regulate GHG emissions under the Clean Air Act, greenhouse gases (including CO_2) became a regulated New Source Review (NSR) pollutant as of January 2, 2011. A summary of the GHG permitting and control regulations is provided below.

3.8.1 Greenhouse Gas Tailoring Rule

On May 13, 2010, U.S.EPA released a final rule intended to clarify how CAA permitting requirements, including the PSD program, will be applied to GHG emissions from power plants and other stationary facilities. The rule is commonly known as the "Tailoring Rule" because it adjusts the PSD threshold requirements applicable to other NSR-regulated pollutants to make them appropriate for GHG emissions.

The Tailoring Rule applies to six GHGs: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). Because some GHGs have greater potential to effect global warming than others, the rule expresses GHG emission thresholds in "carbon dioxide equivalents" or "CO_2e". The CO_2e metric translates emissions of gases other than CO_2 into the CO_2 equivalent based on the climate change potential of each gas. Total GHG emissions are calculated by summing the CO_2e emissions of all six regulated GHGs. The Tailoring Rule establishes two initial steps for phasing in regulation of GHGs:

Step 1 (January 2, 2011, through June 30, 2011)

- GHGs must be addressed in PSD pre-construction permits for new or modified facilities that require a PSD permit based on their emissions of other regulated pollutants (sulfur dioxide, particulate matter, etc.) and that increase net GHG emissions by at least 75,000 tons per year CO_2e.
- GHGs must be addressed in Title V operating permits for all facilities that require a Title V permit based on their emissions of other regulated pollutants.

Step 2 (July 1, 2011, through June 30, 2013)

- GHGs must be addressed in PSD pre-construction permits for new facilities that have the potential to emit at least 100,000 tons per year CO_2e, even if they would not require a PSD permit based on their emissions of other regulated pollutants.
- GHGs must be addressed in PSD pre-construction permits for modifications of existing facilities that increase net GHG emissions by at least 75,000 tons per year CO_2e, even if they would not require a PSD permit based on their emissions of other regulated pollutants.
- GHGs must be addressed in Title V operating permits for all facilities that have the potential to emit at least 100,000 tons per year CO_2e, even if they would not require a Title V permit based on their emissions of other regulated pollutants.

The BREC generation stations are already required to have Title V Operating Permits based on emissions of other regulated pollutants, and have the potential to emit considerably more than 100,000 tons per year CO_2e. Therefore, the BREC facilities will need to modify their existing Title V Operating Permits to address GHG emissions; however, this regulatory requirement is independent of any air pollution reduction requirements.

With respect to triggering PSD review, after July 1, 2011, GHGs must be addressed in PSD pre-construction permits for modifications of existing facilities that increase net GHG emission by at least 75,000 tpy CO_2e, even if they do not require a PSD permit based on their emission of other NSR regulated pollutants. The installation of a large air pollution control system is generally considered a non-routine physical change, or change in the method of operation of an existing stationary source. Thus, the installation of a new air pollution control system would fall under the definition of "modification" if it results in a significant net increase in emissions of an NSR-regulated pollutant, and would be subject to the NSR-PSD permitting. A detailed emissions netting calculation, taking into consideration impacts to the net plant heat rate, auxiliary power requirements, and direct emissions associated with the air pollution control system would need to be completed to determine whether the project would trigger NSR for GHG emissions.

3.8.2 Greenhouse Gas BACT Requirements

PSD permitting requires facilities to apply BACT, which is determined on a case-by-case basis taking into account, among other factors, the cost and effectiveness of available control systems. In the Tailoring Rule EPA stated that it planned to develop supporting guidance to assist permitting authorities as they begin to address permitting actions for GHG emissions, and that it was working with the Clean Air Act Advisory Committee and others to develop the technical information and data needs related to identifying BACT requirements for PSD permits. EPA published its GHG guidance document on November 22, 2010. A copy of the guidance document is available at: http://www.epa.gov/nsr/ghgpermitting.html.

Currently, there are no CO_2 control technologies operating at a commercial scale on an existing coal-fired EGU. Several technology suppliers are working to develop and demonstrate systems that may be ready for commercial deployment in the 2015 – 2018 timeframe. The first commercial CO_2 capture systems are expected to be solvent based absorption systems. The most mature solvents are amines and ammonia. The amines and ammonia solvents have two major factors in common: (1) SO_2 must be minimized before contact with the solvent; and (2) the flue gas must be cooled before entering the absorber. With respect to SO_2 concentrations in the flue gas, both CO_2 systems (amine and ammonia) require low SO_2 concentrations for effective CO_2 capture. For future commercial applications, it is expected that the concentration of SO_2 entering the CO_2 capture system must be reduced to a level of 1 - 10 ppmv for stable long term operation. The concentration of SO_2 leaving a conventional wet or dry FGD control system will be in the range of 20 – 40 ppmv. Therefore, regardless of the FGD technology installed, it appears that a polishing SO_2 scrubber would be required ahead of the CO_2 control system.

3.8.3 Greenhouse Gas Legislation

Over the past couple of years, several legislative initiatives have been introduced in Congress addressing greenhouse gas (GHG) emissions, clean energy technologies, climate change, and energy efficiency. To become law, any GHG legislation must be approved independently by both the House of Representatives and the Senate, coming together in conference committee to reconcile any differences. This process must be completed during the same two-year congressional session.

In June 2009, the House of Representatives passed the American Clean Energy and Security Act of 2009 (H.R. 2454). The bill included a GHG cap-and-trade program that encompassed most large industrial sectors (including power plants), and included emission caps that would reduce aggregate GHG emissions to 3% below their 2005 levels in 2012; 17% below 2005 levels by 2020; 42% below 2005 levels by 2030, and 83% below 2005 levels by 2050. The bill also included provisions related to a federal renewable electricity and efficiency standard, carbon capture and storage technology development, performance standards for new coal-fired power plants, R&D support for electric vehicles, and support for deployment of smart grid advancement.

However, the Senate did not produce a companion bill. Several senate bills were considered in 2010, including the American Clean Energy Leadership Act (S.1462) and the American Power Act (S.1733). The American Clean Energy Leadership Act (sponsored by Senator Bingaman) sought to accelerate the introduction of new clean energy technologies and increase energy efficiency, but did not set a price on carbon and did not have quantifiable reductions in GHG emissions. The American

Power Act (sponsored by Senators Kerry and Lieberman) sought to achieve aggregate GHG emission reductions of 20% below 2005 levels by 2020 and by 83% by 2050 through a nationwide cap-and-trade program. The bill also included provisions encouraging investments in clean energy technology and the creation of green jobs. Ultimately, no action was taken by the 111th Congress with respect to GHG emissions from existing stationary sources, and, at this time (June 2011) it appears unlikely that 112th Congress will take-up GHG legislation during this congressional session.

4.0 National Pollutant Discharge Elimination System (NPDES) Regulations

U.S.EPA implements many of the Federal Clean Water Act (CWA) requirements through National Pollutant Discharge Elimination System (NPDES) permits. For example, the §316(a) thermal discharge requirements, §316(b) cooling water intake structure standards, and the categorical effluent standards are regulated through the NPDES permitting program. EPA is actively working on revising two CWA regulations that could have a significant impact on the design and operation of coal-fired electric generating units; the §316(b) cooling water intake structure regulations, and the Part 423 steam electric effluent guidelines. A discussion of each regulatory initiative is provided below.

4.1 Clean Water Act Section 316(b) Regulations

On April 20, 2011 U.S.EPA published in the Federal Register proposed regulations implementing §316(b) of the CWA at all existing power generating facilities and all existing manufacturing and industrial facilities that withdraw more than 2 million gallons per day (MGD) of water from waters of the U.S. and use at least 25% of the water they withdraw exclusively for cooling purposes (the "Proposed §316(b) Rule"). The proposed rule would establish national §316(b) requirements applicable to cooling water intake structures at these facilities by setting requirements that reflect the best technology available (BTA) for minimizing adverse environmental impacts. The proposed requirements would be implemented through the NPDES permit program, and incorporated into existing permits. In many cases, regulated entities are required to begin planning and initiate studies within 6 months of promulgation of the final rule.

EPA is currently receiving comments on the Proposed §316(b) Rule. Comments must be received by EPA on or before July 19, 2011. After the close of the public comment period, EPA is required to review and respond to all substantive comments, and sign for publication a final rule. Publication of a final rule is expected by July 27, 2012.

4.1.1 Proposed §316(b) Rule - Applicability

The Proposed §316(b) Rule applies to existing facilities that meet all of the following characteristics:

- ✓ Construction of the facility commenced before January 17, 2002;
- ✓ The facility is a point source subject to NPDES permitting;
- ✓ The facility uses (or proposes to use) cooling water intake structures with a total design intake flow of greater than 2 MGD to withdraw water from waters of the U.S.; and
- ✓ 25% or more of the water it withdraws is used exclusively for cooling purposes (measured on an average annual basis for each calendar year).

4.1.2 Proposed §316(b) Performance Standards

The Proposed §316(b) Rule includes both impingement mortality (IM) and entrainment (E) performance standards applicable to existing power generating facilities. Proposed IM&E performance standards are based on EPA's determination of BTA taking into consideration the availability and feasibility of various technologies; technology costs and economic impacts; effects on energy production, availability, and reliability; and potential adverse environmental effects that may arise from using the different controls evaluated.

There are three general components to the proposed regulation. First, most facilities would be subject to an upper limit on impingement mortality. Facilities would determine which impingement control technology would be best suited to achieve this limit; for example, facilities could install modified traveling screens and fish return systems, or reduce the intake velocity to 0.5 fps or less. Second, facilities that withdraw >125 MGD would be required to conduct additional studies to help their permitting authority determine what site-specific entrainment mortality controls, if any, would be required. Third, new units at an existing facility that are built to increase the generating capacity of the facility would be required to reduce the intake flow to a level commensurate with closed-cycle cooling.

Proposed impingement mortality and entrainment performance standards included in the rule are summarized below.

4.1.2.1 **Impingement Mortality Performance Standards**

The Proposed §316(b) Rule includes two options for meeting BTA for impingement mortality. First, the owner/operator of an existing cooling water intake structure may monitor to show that specified performance standards for impingement mortality have been met. As an alternative, the owner/operator may demonstrate that the intake velocity meets specified design criteria.

Impingement Mortality Option 1: Option 1 requires the owner or operator of an existing facility to install, operate, and maintain control technologies capable of achieving the following impingement mortality limitations for all life stages of fish:

Impingement Mortality Not to Exceed		
Regulated Parameter	Annual Average	Monthly Average
Fish Impingement Mortality	12%	31%

The proposed impingement mortality performance standards are based on the operation of a modified coarse mesh traveling screen with fish buckets, a low pressure spray wash, and a dedicated fish return line. However, the proposed rule does not specify any particular screen configuration, mesh size, or screen operation, so long as facilities can continuously meet the numeric impingement mortality limits. Option 1 compliance monitoring requirements are described below.

To demonstrate compliance with the Option 1 IM standards (i.e., impingement mortality control technologies), the facility would be required to monitor impingement mortality at each intake structure. Monitoring would be required at a frequency specified by the permitting agency; however, EPA assumes the facility would monitor no less than once per week during primary periods of impingement, and no less than biweekly during all other times.

For each monitoring event, the facility would determine the number of organisms that are collected or retained on a 3/8th inch sieve (i.e., impinged [I] organisms), and the number of impinged organisms that die within a 48 hours of impingement (i.e., impingement mortality

[IM]). Fish that are included in any carryover from a traveling screen and fish removed from a screen as part of debris removal would be counted as part of the impingement mortality. Naturally moribund fish and invasive species would be excluded from the totals for both impingement and impingement mortality.

The percentage of impingement mortality is defined as: %IM = (IM / I) x 100

For each calendar month, the facility would calculate the arithmetic average of the percentage IM observed during each of the sampling events, and compare the results to the applicable performance standard.

Impingement Mortality Option 2: Under Option 2, a facility may chose to comply with the impingement mortality standards by demonstrating to the permitting agency that its cooling water intake system has a maximum intake velocity of 0.5 feet per second (fps).

The maximum velocity must be demonstrated as either the **maximum design intake velocity** or the **maximum actual intake velocity** as water passes through the structural components of a screen measured perpendicular to the screen mesh. Typically, this intake velocity will correspond to the through-screen velocity. The maximum velocity limit must be achieved under all conditions, including during minimum ambient source surface elevations and during periods of maximum head loss across the screens during normal operation of the intake structure.

There are no compliance monitoring requirements for facilities that can document a **maximum design intake flow velocity** (DIF) equal to or less than 0.5 fps under all operating conditions. If the facility cannot document a design intake velocity of ≤ 0.5 fps, the facility must demonstrate a **maximum actual intake flow velocity** (AIF) of 0.5 fps or less as water passes through the structure components of the intake structure (typically the through-screen velocity). Maximum velocities must be demonstrated under all operating conditions including during minimum ambient source water surface elevations and maximum head loss across the screens. Compliance monitoring will be required to demonstrate that the maximum actual intake velocity remains below 0.5 fps. Monitoring frequency would be established in the permit, but would be no less than twice per week.

In addition, facilities that choose IM Option 2 must operate and maintain each intake to keep any debris blocking the intake at no more than 15% of the opening of the intake. A demonstration that the actual intake velocity is less than 0.5 fps through velocity measurements will meet this requirement.

The proposed rule does not specify that the owner/operator of a facility with a cooling water intake structure that supplies cooling water exclusively for operation of a cooling tower is deemed to meet the IM standards. This is because the largest facilities with closed-cycle cooling still have the potential to withdraw significant quantities of makeup water. Therefore, existing units with cooling water intake structures that supply make-up water to cooling towers are also subject to these IM performance standards.

4.1.2.2 Entrainment Performance Standards

The Proposed §316(b) Rule includes entrainment mortality performance standards applicable to existing units with a design intake flow >2 MGD, existing units with a design intake flow >125 MGD, and new units. Proposed entrainment performance standards are summarized below.

Existing Units: For entrainment mortality, the proposed rule establishes requirements for studies as part of the permit application, and then establishes a process by which BTA for entrainment mortality would be implemented at each facility on a case-by-case basis. These case-by-case performance standards must reflect the permitting agency's determination of the maximum reduction in entrainment mortality warranted after consideration of all factors relevant for determining BTA at each facility. Factors that the permitting agency must consider when making a case-by-case entrainment mortality determination include:

- Number and types of organisms entrained;
- Entrainment impacts on the waterbody;
- Quantified and qualitative social benefits and social costs of available entrainment technologies, including ecological benefits and benefits to any threatened or endangered species;
- Thermal discharge impacts;
- Impacts on the reliability of energy delivery within the immediate area;
- Impact of changes in particulate emissions or other pollutants associated with entrainment technologies;
- Land availability inasmuch as it relates to the feasibility of entrainment technology;
- Remaining useful plant life; and
- Impacts on water consumption.

In addition, existing facilities with an actual intake flow of greater than 125 MGD must conduct additional entrainment mortality studies and evaluations as part of the BTA determination, including:

- Entrainment Mortality Data Collection Plan (with peer reviewers identified);
- Peer reviewed Entrainment Mortality Data Collection Plan;
- Completed Entrainment Characterization Study;
- Comprehensive Technical Feasibility and Cost Evaluation Study, including:
  - Benefits Valuation Study; and
  - Non-water Quality and Other Environmental Impacts Study.

4.1.3 Implementation of the §316(b) Performance Standards

The requirements of the Proposed §316(b) Rule would be applied to individual facilities through NPDES permits issued by EPA or authorized States. All existing facilities would be required to complete and submit application studies to describe the source waterbody; cooling water intake structures; cooling water system; characterize the biological community in the vicinity of the cooling water intake structure; develop a plan for controlling impingement mortality; describe biological survival studies that address technology efficacy; and discuss the operational status of the facility. Facilities withdrawing more than 125 MGD, and existing facilities with new units, would also complete and submit studies to characterize entrainment mortality and assess the costs and benefits of installing various potential technological and operational controls.

As proposed, facilities would have to comply with the impingement mortality requirements as soon as possible; however, facilities may request additional time to comply with the requirements. Permitting authorities would have discretion to set a timeline for compliance, but in no event can the deadline be later than 8 years after the effective date of the rule. Compliance with the entrainment standards would be required "as soon as possible," with the compliance date established by the permitting authority. Assuming the §316(b) rules are finalized in 2012, compliance with the impingement mortality performance standards would be expected in the 2016-2018 timeframe, and compliance with the case-by-case entrainment standards would be expected in the 2018-2020 timeframe.

A brief summary of the applicable §316(b) regulations is provided in Table 4-1, and a summary of the proposed §316(b) permit application and impingement/entrainment study requirements is provided in Table 4-2.

Table 4-1: Proposed §316(b) Regulatory Review

Coleman Generating Station	Wilson Generating Station	Sebree Generating Station
KPDES permit No. KY001937 Source Water: Ohio River Condenser Cooling System: Once-through Design Intake Flow = 356.73 MGD Cooling water is obtained from the Ohio River through the facility's cooling water intake structure. The water balance provided for the Coleman Station indicates that the cooling water intake structure has a maximum design intake flow of 356.73 MGD. Therefore, the Coleman Station will be subject to all of the §316(b) requirements proposed for facilities >125 MGD. Proposed impingement standards require existing facilities to install, operate, and maintain impingement control technologies (e.g., modified coarse mesh traveling screens with fish collection and return systems), or reduce the maximum intake velocity to 0.5 fps or less. Based on a preliminary review of the cooling water intake structure drawings, the Coleman cooling water intake structure is equipped with 3/8" mesh traveling screens, designed to handle 50,000 gpm at a velocity of 1.78 fps at the low water level of 11'0" and a 100% clean screen. The next phase of the project will evaluate the technical feasibility of modifying the intake structure to reduce the intake velocity to 0.5 fps, installing fish collection and return systems capable of achieving the proposed impingement mortality performance standards, and retrofitting the station with a closed-cycle cooling system. Entrainment requirements for the Coleman Station will be determined on a case-by-case basis, based on the results of the Entrainment Characterization Study.	KPDES Permit No. KY0054836 Source Water: Green River Condenser Cooling System: Closed-cycle cooling Design Intake Flow: 8.64 MGD The water balance provided for Wilson station indicates that the total water intake is 8.64 MGD, and that the plant operates cooling towers at an average of 5.5 – 6.0 cycles of concentration. Therefore, the station will be subject to the §316(b) standards proposed for an existing facility with >2 MGD but less than 125 MGD. Proposed impingement standards require existing facilities to install, operate, and maintain impingement control technologies (e.g., modified coarse mesh traveling screens with fish collection and return systems), or reduce the maximum intake velocity to 0.5 fps or less. Based on a preliminary review of the cooling water intake structure, and the KPDES fact sheet provided for the facility, the facility has an intake velocity of 0.5 fps with 2 pumps in service; thus, the facility may be able to meet the proposed intake velocity standard. Further detailed review of the design of the cooling water intake structure and cooling water make-up flows will be reviewed as part of the next phase of the project to determine whether the station can meet the proposed 0.5 fps velocity limit without additional intake structure modifications. Entrainment requirements for the Wilson Station will be determined on a case-by-case basis.	KPDES permit, No. KY001929 Source Water: Green River Condenser Cooling System: Reid: Once-through cooling Green: Closed-cycle cooling Henderson: Closed-cycle cooling Design Intake Flow: Reid: 60 MGD Green/Henderson: Make-up water Henderson: Make-up water The water balance for the Reid generating unit R01 indicates that the cooling water intake structure has a maximum design intake flow of 60 MGD. Therefore, the intake structure will be subject to the requirements proposed for an existing facility >50 MGD but less than 125 MGD. Proposed impingement standards require existing facilities to install, operate, and maintain impingement control technologies (e.g., modified coarse mesh traveling screens with fish collection and return systems), or reduce the maximum intake velocity to 0.5 fps or less. Drawings for the Reid intake structure show that screens provided for this facility by the Chain Belt Company in 1964 were rated for 72,500 gpm at low water depth of 15.0 feet at a velocity of 2.34 fps. To meet the proposed impingement requirements, the facility will have to retrofit the intake with fish collection & return systems, or reduce the intake velocity to <0.5 fps. Curtailing or ceasing operations at Reid R01 would significantly decrease the cooling water requirements at the Sebree Station, and may allow the facility to meet the velocity requirement without modifications.

Table 4-2: §316(b) Permit Application and Supporting Information Submittal Deadlines

Permit Application Materials	Sebree	Coleman	Wilson
	Existing **power producers** with a design intake flow of 50 MGD or above:	Existing **power producers** with an actual intake flow >125 MGD:	All other existing facilities would submit:
122.21(r)(2) Source water physical data 122.21(r)(3) Cooling water intake structure data 122.21(r)(4) Source water baseline biological characterization data 122.21(r)(5) Cooling water system data 122.21(r)(6) Proposed Impingement Mortality Reduction Plan 122.21(r)(7) Performance studies 122.21(r)(8) Operational status	Information required in §§122.21(r)(2), (r)(3), (r)(4), (r)(5), (r)(6), (r)(7), and (r)(8) must be submitted not later than **6 months** after the effective date of the rule. Results of the Impingement Mortality Reduction Plan (§122.21(r)(6)) must be submitted no later than **3 years and 6 months** after the effective date of the rule.	Information required in §§122.21(r)(2), (r)(3), (r)(4), (r)(5), (r)(6), (r)(7), and (r)(8) must be submitted not later than **6 months** after the effective date of the rule. Results of the Impingement Mortality Reduction Plan (§122.21(r)(6)) must be submitted no later than **3 years and 6 months** after the effective date of the rule.	Information required in §§122.21(r)(2), (r)(3), (r)(4), (r)(5), (r)(6), (r)(7), and (r)(8) must be submitted not later than **3 years** after the effective date of the rule. Results of the Impingement Mortality Reduction Plan (§122.21(r)(6)) must be submitted no later than **6 years** and 6 months after the effective date of the rule.
122.21(r)(9) Entrainment characterization study 122.21(r)(9)(i) Entrainment Mortality Data Collection Plan 122.21(r)(9)(ii) Entrainment Mortality Data Collection Plan (peer reviewed) 122.12(r)(9)(iii) Entrainment Characterization Study		Information required in: 122.21(r)(9)(i): 6 months 122.21(r)(9)(ii): 12 months 122.21(r)(9)(iii): 4 years	
122.21(r)(10) Comprehensive technical feasibility and cost evaluation study		Information required in §122.21(r)(10): 5 years	
122.21(r)(11) Benefits valuation study		Information required in §122.21(r)(11): 5 years	
122.21(r)(12) Non-water quality impacts assessment		Information required in §122.21(r)(12): 5 years	

4.2 Wastewater Discharge Standards

4.2.1 Steam Electric Effluent Guidelines (40 CFR 423)

EPA is considering revising the wastewater discharge standards for the steam electric power point source category. The current version of the effluent limitations guidelines (40 CFR Part 423) were promulgated in 1982. Under the Clean Water Act, EPA is required to periodically review and revise all effluent guidelines. In November 2006, EPA published interim detailed study results for the Steam Electric Power industry. In the October 2007 "Preliminary 2008 Effluent Guidelines Plan," EPA outlined further detailed study that is needed to determine whether Part 423 requires revision or updating.

As part of a multi-year study EPA requested specific coal-fired power plant to provide extensive sampling data regarding 27 metals and several conventional wastewater parameters (e.g., flow, pH, TDS, etc.). Data from the sampling program was used to characterize wastewater from air pollution controls, evaluate treatment system effectiveness, and characterize the pollutants discharged to surface water from steam electric plants. Based on the results of the multi-year study, in September 2009, EPA announced its decision to proceed with revising the Part 423 effluent guidelines.

As part of the rulemaking process, an Information Collection Request (ICR) was distributed in June 2010 to the steam electric power industry. The ICR questionnaire was designed to collect general plant information and selected technical information about the plant processes and the electric generating units. Information collected included economic data, and technical information about flue gas desulfurization waste water, ash handling, process equipment cleaning operations, wastewater treatment, and surface impoundment and landfill operations. The ICR also required certain power plants to collect and analyze samples of leachate from surface impoundments and landfills containing coal combustion residues.

Data from the ICR will be incorporated into technical development documents as part of the effluent guideline rulemaking process. EPA has not yet published proposed revisions to the Part 423 effluent guidelines. EPA has indicated a concern for the transfer of air pollutant into other media, in particular wastewater and leachate or groundwater. Based on these discussions, it is expected that numeric standards for metals will be promulgated for FGD wastewater, and potentially for wastewaters in contact with coal or coal combustion residuals such as ash ponds, gypsum storage piles and landfills. It is anticipated that EPA may publish proposed revisions in mid-2012, and EPA has stated that it will take final action by January 2014. If so, compliance with the new discharge standards would be required in the 2017 – 2018 timeframe.

4.2.2 ORSANCO

Discharges to the Ohio River are also regulated by ORSANCO, the Ohio River Sanitation Commission. Kentucky is a member of ORSANCO. ORSANCO sets Pollution Control Standards for industrial and municipal wastewater discharges to the Ohio River, and tracks certain dischargers whose effluent can seriously impact water quality. The water quality requirements for the Ohio River are more stringent than the current Steam Electric Effluent Guidelines, and have been incorporated into NPDES permits on a site-specific basis. To keep pace with current issues, ORSANCO reviews the standards every three years. As part of the review process, workshops and public hearings are held for public input.

For heavy metals such as mercury, the ORSANCO standards provide insight into the potential targets for the upcoming Steam Electric Power effluent guidelines. The most recent version of the Pollution Control Standards is dated 2010. The standards are based on preventing acute and chronic toxicity to aquatic organisms and to protect human health. Of these standards, the most stringent will apply. For protection of human health, there are several constituents of concern. Among these, mercury is limited to 0.000012 mg/L, arsenic is limited to 0.01 mg/L, and barium is limited to 1.0 mg/L. These metals are not currently limited in 40 CFR 423, but are among those that U.S.EPA has indicated are of interest, due to the fact that they are common in FGD blowdown and in coal. In particular, mercury is regulated as a bioaccumulative substance for which no mixing zone is allowed in the Ohio River after October 16, 2013.[20] Thus, it is expected that compliance with mercury discharge limitations will become a key concern for dischargers to the Ohio River, and potentially for power plants as a group.

The human health standard set by ORSANCO in the Ohio River for chloride and sulfate, both common constituents of cooling tower and FGD blowdown, is 250 mg/L for each. Neither substance is amenable to treatment using conventional technology, as both are soluble in water at concentrations that are hundreds or thousands of times greater than this standard. In the past chloride and sulfate have been managed with mixing zones, but in some areas of the country, (e.g., sections of the Monongahela River in West Virginia and Pennsylvania) stream standards are not being achieved. This means that local discharge limits for chloride and sulfate are being applied using the provisions of §303(d) of the CWA and the total maximum daily load (TMDL) process. In extreme cases, no discharge of wastewater is allowed, based on the background concentrations of chloride or sulfate. Regulation of chloride and sulfate is a developing issue.

4.2.3 **Wastewater Discharge Standards - Summary**

The preceding discussion is not meant to provide an exhaustive review of the parameters with the potential to become regulated, but to provide some insight into the regulatory environment that is currently in place, and a preview of the potentially stringent regulations that could be forthcoming. At this point it is difficult to accurately anticipate what impact these regulations may have on the coal-fired generating station operations. However, EPA has indicated in the October 2009 Detailed Study Report that wastewaters from air pollution control devices are of primary concern, in particular mercury and other heavy metals. A brief summary of the potential wastewater discharge requirements is provided in Table 4-3.

[20] Formerly November 15, 2010

Table 4-3: Potential Wastewater Effluent Discharge

Coleman Generating Station	Wilson Generating Station	Sebree Generating Station
KPDES permit No. KY001937 Receiving Water: Ohio River Because this plant discharges directly to the Ohio River, ORSANCO requirements will apply to the effluent. Even though the effluent guidelines have not yet been promulgated, the concentration of mercury in water entering the river will be required to meet the ORSANCO limit of 0.000012 mg/L (in addition to other metals limitations). The permit also requires the Coleman plant to monitor for total recoverable metals and hardness. The results of this monitoring will be incorporated into the next permit application and may result in numeric discharge limits for these substances. The FGD wastewater and other wastewaters generated by the plant will have to meet the Steam Electric Power Effluent Guidelines, which are expected to be similar to ORSANCO standards. Depending upon the discharge limits for mercury and other constituents in the KPDES permit it may become necessary to install advanced wastewater treatment/removal systems for mercury and other metals.	KPDES Permit No. KY0054836 Receiving Water: Green River and Elk Creek The KPDES permit requires monitoring for hardness, sulfate, and chloride. The results of this monitoring may be used to demonstrate the need for numeric effluent standards for these parameters in future permits. Further, the required monitoring for total recoverable metals indicates a potential for future limits based on the data developed. It is expected that the new Steam Electric Power Effluent Guidelines will result in more stringent effluent requirements for this facility. The existing permit fact sheet relied heavily on the requirements of 40 CFR 423. Depending upon the discharge limits for sulfates, chlorides, mercury and other constituents in the KPDES permit it may become necessary to install advanced wastewater treatment/removal systems for mercury and other metals.	KPDES permit, No. KY001929 Receiving Water: Green River The Green and Henderson facilities are equipped with cooling towers that contribute 0.08 MGD and 8.21 MGD respectively to the overall discharge. Because the facilities discharge to the Green River, it is expected that the new Steam Electric Power Effluent Guidelines will drive the effluent limits. The facility currently has a 1,200 ppm chloride limit. Cooling tower blowdown and FGD blowdown may contain high levels of chloride, which is difficult and expensive to remove. The permit also requires monitoring for total recoverable metals & hardness, indicating a potential for numeric effluent standards for metals in the next round of permitting. It is not known whether the potential numeric standards will be more or less stringent than any that may be proposed in the update of 40 CFR 423. Depending upon the discharge limits for sulfates, chlorides, mercury and other constituents in the KPDES permit it may become necessary to install advanced wastewater treatment/removal systems for mercury and other metals.

5.0 Coal Combustion Residue Regulations

On May 4, 2010, EPA proposed alternative approaches to regulate the disposal of coal combustion residuals (CCRs), including both ash and flue gas desulfurization wastes, generated by electric utilities and independent power producers. Beneficial use of CCRs in products such as concrete or wallboard would be not regulated under the proposal. Placement of CCRs as fill in quarries or gravel pits would be considered disposal and would be regulated, but placement in coal mine voids would not.

The proposal requests comments on two primary alternatives: one would regulate CCRs as "special wastes" under the hazardous waste provisions of Subtitle C of the Resource Conservation and Recovery Act (RCRA); the other would regulate CCRs under the non-hazardous waste provisions of RCRA Subtitle D. An important difference between the two is that the Subtitle C approach would regulate CCRs from the point of generation through the point of final disposal. This would include stringent requirements for facilities that generate, transport, store, treat, and dispose of CCRs. The Subtitle D approach, in contrast, would regulate only the disposal of CCRs. However, the disposal requirements of the two approaches have many similarities, including standards for siting, liners, groundwater monitoring, corrective action for releases, closure of disposal units, and post-closure care.

Other significant differences and similarities are summarized below:

Effective Dates: Under Subtitle C, the effective date of the requirements would be variable, because each state would have to develop and promulgate its own implementing regulations. According to EPA, this process could take 2 years or more. Under Subtitle D, the proposed federal standards would take effect within 180 days after promulgation of the final rule.

Enforcement: Subtitle C would allow for enforcement by EPA and state agencies, while Subtitle D would not be enforced by EPA. States could enforce their Subtitle D regulations, and citizens could file lawsuits against offending facilities.

Permitting: Under Subtitle C, regulated facilities would be required to obtain permits for the units in which CCRs are disposed, treated, and stored. Under Subtitle D, there would be no federal permitting requirements, but states would be free to require permits under their own regulations.

Existing Surface Impoundments: Under Subtitle C, surface impoundments constructed before the rule is finalized must either remove solids and retrofit the impoundment with a composite liner within 5 years of the effective date, or stop receiving CCRs within 5 years and then close the unit within 2 years thereafter. Under Subtitle D, existing surface impoundments must remove solids and retrofit with a composite liner, or stop receiving CCRs and close the unit within 5 years of the effective date.

Existing Landfills: Under either Subtitle C or Subtitle D, landfills built before the rule is finalized are not required to retrofit with a new liner or leachate collection system. However, under either approach, an existing landfill must comply with groundwater monitoring requirements.

New Surface Impoundments: Under either Subtitle C or Subtitle D, surface impoundments constructed after the rule is finalized are required to meet a new set of technological requirements specific to CCRs. These requirements include a composite liner and a leachate collection and removal system. In addition, under Subtitle C, CCRs are subject to treatment requirements that EPA has stated are intended to phase out the use of new surface impoundments.

New Landfills: Under either Subtitle C or Subtitle D, new landfills and lateral expansions of existing landfills must meet technological requirements that include composite liners, leachate collection and removal systems, and groundwater monitoring.

As stated above, the proposal does not intend to regulate the beneficial use of CCRs. However, industry representatives have raised concerns that the Subtitle C approach could have a detrimental effect on beneficial use, because of the permitting and technical requirements that might apply to the storage and transportation of CCRs before they are used. In addition, the proposal requests comments on possible changes to the definition of beneficial use, intended to clarify when the use of CCRs constitutes an exempt beneficial use. Specifically, EPA has proposed to consider the following factors in deciding whether a use is beneficial: (i) the CCR used must provide a functional benefit; (ii) the CCR used must substitute for the use of a natural material, thereby conserving a natural resource; and (iii) CCRs would be expected to meet any applicable product specifications, regulatory standards, or relevant agricultural standards. EPA has not published an expected date for finalizing the rule after comments are considered.

The CCR regulations could have a significant impact on the design and operation of existing solid waste disposal facilities if EPA chooses to regulate CCR as "special wastes" under the hazardous waste provisions of Subtitle C of RCRA. If EPA chooses to regulate CCR disposal under the non-hazardous waste provisions of RCRA Subtitle D, potential impacts would be less significant. Modifications to existing CCR material handling systems to comply with the new regulations will likely be required in the 2016-2018 timeframe.

6.0 Environmental Regulatory Impact Summary

EPA has been actively developing environmental regulations that may impact coal-fired power plant operations. Future regulations are expected to require additional reductions the criteria air pollutants including SO_2, NOx, CO, and PM (including condensible $PM_{2.5}$), and may compel existing units to control additional air pollutants including mercury, acid gases, trace metals, and potentially CO_2. In addition, future regulatory initiatives will likely include more stringent requirements for cooling water intake structures, wastewater discharges, and disposal of coal combustion residues. A summary of the current and proposed environmental regulations that may affect operations at the BREC generating facilities are listed below and summarized in Table 7-1.

6.1 CAIR (2010 – 2012):

Summary: CAIR is an existing regulation that currently requires BREC to meet certain annual SO_2, annual NOx, and seasonal NOx allowance requirements. CAIR is a cap-and-trade program which allows BREC to allocate surplus allowances from one unit to cover excess emissions at another.

SO_2: Total annual SO_2 emissions from all BREC units are at, or slightly below, the CAIR allowance requirements. No new SO_2 control technologies are needed to meet the CAIR SO_2 allocation requirements.

NOx: Total NOx emissions from the BREC units need to be reduced by approximately 3.4% to match the annual and seasonal CAIR NOx allocations. Relatively small NOx emission reductions on the non-SCR controlled units (i.e., Coleman and Green Units) could provide the emission reductions needed to meet the CAIR NOx allowance requirements.

6.2 Cross-State Air Pollution Rule (2012 – 2014/16):

Summary: CSAPR will replace CAIR in 2012. CSAPR includes new annual SO_2, annual NOx, and seasonal NOx cap-and-trade programs. Because CSAPR is a cap-and-trade program, BREC will be able to allocate surplus allowances from one unit to cover excess emissions at another.

SO_2: CSAPR includes a 2-phase SO_2 allocation program. The first phase will replace CAIR beginning in 2012, and the second-phase will result in reduce SO_2 allowance caps beginning in 2014.

2012 SO_2: Total SO_2 emissions from the BREC units should be at, or slightly below, the 2012 CSAPR SO_2 allocations. No new SO_2 control technologies are needed to meet the 2012 CSAPR SO_2 requirements.

2014 SO_2: Total SO_2 emissions from the BREC units are above the 2014 CSAPR SO_2 allocations. Baseline annual BREC SO_2 emissions average approximately 25,575 to 27,286 tpy, compared to the 2014 CSAPR allowance allocations of 13,643 tpy. Systemwide SO_2 emissions need to be reduced by approximately 50% to meet the 2014 CSAPR allowance requirements.

NOx: The CAIR annual and seasonal NOx cap-and-trade programs will be replaced by the CSAPR cap-and-trade programs in 2012. Annual and ozone season NOx allowances will be allocated for 2012 and 2013, and revised somewhat in 2014. In general, 2014 NOx allowance allocations are somewhat lower than the 2012 allocations.

Annual NOx: Total NOx emissions from the BREC units are expected to exceed the 2012 and 2014 CSAPR annual NOx allowance allocations. BREC will receive 11,186 annual NOx allowances in 2012/13 and 10,142 annual NOx allowances in 2014. Baseline 2010 NOx emissions from the BREC units totaled 12,074 tons. Systemwide NOx emissions need to be reduced by approximately 16% to meet the 2014 CSAPR NOx allowance allocations.

Seasonal NOx: Similarly, seasonal NOx emissions from the BREC units are expected to exceed the 2012 and 2014 CSAPR seasonal NOx allowance allocations. BREC will receive 4,972 seasonal NOx allowances in 2012/13 and 4,402 seasonal NOx allowances in 2014. Baseline 2010 ozone season NOx emissions from the BREC units totaled 4,995 tons. Systemwide NOx emissions need to be reduced by approximately 12% to meet the 2014 CSAPR NOx allowance allocations.

6.3 Utility MACT (2015/16):

Summary: EPA published the Proposed Utility MACT Rule on May 3, 2011. The proposed rule regulates HAP emissions from coal and oil-fired EGUs. In the rule EPA proposed emission standards for mercury, acid gases, and non-mercury trace metal HAPs. EPA is expected to publish a final rule in November 2011 with compliance required by the end of 2014.

Hg: Based on a review of available stack test data, it appears that the BREC Units H01 and H02 will meet the proposed MACT Hg standard of 1.2 lb/TBtu. Mercury emissions from the BREC Units C01, C02, C03, G01, G01 and W01 have been measured between 1.77 and 3.52 lb/TBtu, and mercury emissions from Unit R01 were measured at 6.5 lb/TBtu. Control technologies capable of providing additional mercury reduction will need to be evaluated for these units.

Acid Gases: The Proposed Utility MACT includes two acid gas compliance options: (1) SO_2 emissions at 0.20 lb/MMBtu (30-day average); or (2) HCl emissions at 0.002 lb/MMBtu.

MACT SO_2 Limit: Baseline SO_2 emissions from the Green Units (ESP+FGD) are below the proposed SO_2 MACT limit. Baseline SO_2 emissions from the other FGD-equipped units (i.e., C01, C02, C03, W01, H01, and H02) are above the proposed SO_2 MACT limit, averaging between approximately 0.25 lb/MMBtu (Coleman Units) and 0.51 lb/MMBtu (Unit W01). The next phase of this project will evaluate the technical/economic feasibility of achieving the proposed SO_2 MACT limit on the FGD-controlled units. If BREC chooses the SO_2 compliance option, continuous compliance with the MACT standard would be demonstrated using the existing SO_2 CEMS.

MACT HCl Limit: Based on a review of available emissions data, it appears that HCl emissions from the BREC units equipped with an FGD control system will be below the proposed MACT limit of 2.0 x 10^{-3} lb/MMBtu. If BREC chooses to demonstrate compliance with the HCl emission limit rather than the SO_2 emission limit, continuous compliance with the MACT standard would be demonstrated using an HCl CEMS, or BREC may implement an on-going stack testing program.

Non-Hg Trace Metal HAPs: The Proposed Utility MACT includes three compliance options for non-Hg trace metal HAP emissions: (1) TPM; (2) total non-Hg metals; and (3) individual non-Hg metals.

TPM: Based on a review of the available emission data, TPM emissions from the BREC Units G01, G01 and W01 are below the proposed MACT limit of 0.030 lb/MMBtu and have been measured between 0.017 and 0.02 lb/MMBtu. TPM emissions from BREC Units H01, H02, C01, C02 and C03 exceed the proposed MACT emission limit of 0.03 lb/MMBtu. TPM emissions from Unit R01 were not measured but are expected to be significantly above the MACT limit based on previous CPM data. Control technologies capable of providing particulate removal will need to be evaluated for these units. The next phase of this project will evaluate control technologies capable of reducing both FPM and CPM emissions, especially on the units equipped with SCR. Technologies available to reduce FPM include ESP upgrades and modifications. Technologies capable of reducing CPM emissions include low-oxidation SCR catalyst, dry sorbent injection, and wet ESP.

Non-Hg Metal Options: Based on a review of the recent stack emissions data, none of the BREC units meet the total or individual non-Hg HAP proposed MACT emission limits. Although G02 and W01 are relatively close to the proposed MACT allowable emissions, choosing the non-Hg compliance alternatives present significant risk because of the lack of control options available for some metals. If BREC chooses to comply with the one of the non-Hg metal alternatives (rather than the TPM option) demonstrating continuous compliance will likely be more onerous and require implementation of an on-going stack testing program.

6.4 NAAQS Revisions or Phase II CSAPR (2016/18):

Summary: EPA has recently proposed and/or finalized several NAAQS revisions. The NAAQS revisions will likely increase the number of 8-hour ozone and PM2.5 nonattainment areas in Kentucky and other downwind states. One regulatory approach that is being considered to address the revised NAAQS is to modify the Cross-State Air Pollution Rule. Modifications to CSAPR would likely include reductions to each States' CSAPR emission allowance budgets, and a corresponding reduction in the number of allowances allocated to each unit. For this evaluation it was assumed that the Phase II CSAPR allocations would be 20% below the 2014 CSAPR allocations, and that the reduced caps would become effective in the 2016-2018 timeframe.

The 1-hour SO_2 NAAQS may also have a significant impact on SO_2 control requirements in the 2016-2018 timeframe. Preliminary modeling results from existing sources suggest that

SO_2 emissions from coal-fired power plants that are not equipped with FGD, and facilities with relatively short stacks, may have modeled exceedances of the 1-hour SO_2 standard. If so, SIP modifications implemented to address the 1-hour SO_2 standard could require additional SO_2 reductions from uncontrolled plants in the 2016-2018 timeframe.

6.5 Tailoring Rule and Greenhouse Gas Regulations (2011):

Summary: The Tailoring Rule is final rule. The rule triggers PSD permitting if modifications are made to an existing major stationary source resulting in increased annual GHG emissions of 75,000 tpy or more CO2e.

GHG and CO2 Emissions: Modifications to an existing major source, including the installation of advanced air pollution control systems, can result in increase annual GHG emissions. A detailed emissions netting calculation, taking into consideration impacts to the net plant heat rate, auxiliary power requirements, and direct emissions associated with the air pollution control system should be completed for each proposed air pollution control project to determine if the project would trigger NSR review of GHG emissions.

6.6 §316(b) Cooling Water Intake Impingement/Entrainment:

Summary: EPA published proposed §316(b) regulations on April 20, 2011. The proposed regulations implement §316(b) of the CWA at all existing power generating facilities that withdraw more than 2 MGD of water from waters of the US. and use at least 25% of the water exclusively for cooling purposes.

Impingement Mortality Standards: All of the BREC generating facilities will be required to meet the proposed impingement mortality standards. In general, the proposed §316(b) regulations require existing facilities that withdraw greater than 2 MGD cooling water to install, operate, and maintain impingement control technologies (e.g., modified coarse mesh traveling screens with fish collection and return systems) capable of meeting specific impingement mortality standards, or to modify the existing intake structure to achieve a maximum intake velocity of 0.5 fps or less.

Entrainment Standards: Entrainment standards will be implemented at each facility on a case-by-case basis.

Table 6-1: Environmental Regulation/Legislation Summary:

Rule		CAIR / Tailoring Rule		Cross-State Air Pollution Rule (CSAPR)			Utility MACT	NAAQS/CSAPR Phase II
Compliance Timeframe		2010/2011		2012	2013	2014	2015	2016 – 2018
Rule Requirements		CAIR includes an annual SO_2 cap-and-trade program, as well as annual and ozone season NOx cap-and-trade programs.	The Tailoring Rule triggers PSD for GHG emissions if modifications to an existing unit result in increased annual emissions of 75,000 tpy or more CO2e.	CSAPR will replace the CAIR cap-and-trade programs with new SO_2 and NOx cap-and-trade programs. CSAPR will not allow the use of banked ARP allocations.		CSAPR Group 1 SO2 allocations (including Kentucky) will be reduced in 2014	The Utility MACT will limit HAP emissions from existing coal-fired boilers.	Revisions to the National Ambient Air Quality Standards could trigger SIP modifications, or revisions to the CSAPR allocation budgets.
Compliance Timeframe		CAIR is currently in place, and will remain in place until EPA passes the CAIR replacement rule (CSAPR).	The Tailoring Rule is a final rule.	The Cross-State Air Pollution Rule will replace CAIR beginning in 2012.			Proposed Utility MACT Rule published on May 3, 2011. The final rule is anticipated to be published in November 2011, with compliance required within 3-years of the final rule.	Anticipated that EPA will address the revised PM2.5 and 8-hour ozone NAAQS through a Phase II CSAPR. The Phase II rule would replace the Phase I CSAPR in the 2016-2018 timeframe.
SO_2	Systemwide	• Total annual SO2 emissions from the BREC units are equal to, or slightly below, the CAIR allocation requirements. • Baseline Annual SO2 emissions = 25,575 tpy (or 51,150 allocations) compared to CAIR allocations of 52,470 tons. • No new SO2 control technologies are needed to meet the CAIR SO2 allocation requirements.		• Total SO2 emissions from the BREC units should be at, or slightly above, the 2012 CSAPR allocations. • Baseline Annual SO2 emissions = 25,575 to 27,286 tpy. • 2012 CSAPR allocations = 26,478 tpy • BREC should be able to meet its 2012 CSAPR SO2 allowance requirements without additional SO2 controls.		• Total SO2 emissions from the BREC units will be above the 2014 CSAPR allocations. • Baseline Annual SO2 emissions = 25,575 to 27,286 tpy. • 2014 CSAPR allocations = 13,643 tpy • Systemwide SO2 emissions need to be reduced by approximately 50% to meet the 2014 CSAPR SO2 allocations.	The Proposed Utility MACT includes an SO2 emission limit of 0.20 lb/MMBtu (30-day average) as a surrogate for acid gas control. All BREC FGD control systems will be evaluated to determine the feasibility of achieving a controlled SO2 emission rate of 0.20 lb/MMBtu (30-day average).	• Assuming the Phase II CSAPR SO2 allocations are 20% below the Phase I 2014 allocations, total SO2 emissions from the BREC units will exceed the Phase II CSAPR allocations. • Baseline annual SO2 emissions = 25,575 to 27,286 tpy. • Projected Phase II CSAPR SO2 Allocations = 10,914 tons. • Average SO2 emissions from all BREC generating units need to be reduced to an average controlled SO2 emission rate of approximately 0.15 lb/MMBtu to meet the projected Phase II allocations.
	Coleman	• The wet lime control system on C01, C02, and C03 is capable of reducing SO2 emissions below the facility's CAIR SO2 allowance requirements.		• The wet lime control system on C01, C02, and C03 should be capable of reducing SO2 emissions below the facility's 2012 CSAPR SO2 allowance requirements.		• Baseline SO2 emissions from units C01, C02, and C03 need to be reduced from 0.25 lb/MMBtu to a controlled rate of 0.20 lb/MMBtu to meet the facility's 2014 CSAPR SO2 allowance requirements.		
	Wilson	• Baseline SO2 emissions from W01 are above the unit's CAIR SO2 allowance requirements. • W01 baseline SO2 emissions = 9,438 tpy (or 18,876 allocations) compared to allocations of 12,641 tons. • Surplus allowances from other BREC units can be used to offset excess SO2 emissions from Unit W01.		• Baseline SO2 emissions from W01 will be above the unit's 2012 CSAPR SO2 allocations. • Baseline SO2 emissions = 9,438 tpy • 2012 CSAPR SO2 allocations = 8,400 tpy • SO2 emissions from W01 need to be reduced from a baseline rate of 0.51 lb/MMBtu to a controlled rate of 0.45 lb/MMBtu to meet its 2012 CSAPR allocations • Surplus allowances from the other BREC units can be used to offset excess SO2 emissions from W01.		• Baseline SO2 emissions from W01 need to be reduced from 0.51 lb/MMBtu to a controlled rate of 0.20 lb/MMBtu to meet the facility's 2014 CSAPR allocations requirements.		
	Sebree	• The wet lime control systems on G01, G02, H01, and H02 are capable of reducing SO2 emissions below each units' CAIR SO2 allowance requirements. • SO2 emissions R01 exceed the CAIR allocations; however, surplus allowances from the other units can be used to offset excess SO2 emissions from Unit R01.		• The wet lime control systems on G01, G02, H01, and H02 are capable of reducing SO2 emissions below each units' 2012 CSAPR allocations. • Baseline SO2 emissions from R01 are above the unit's 2012 CSAPR allocations. • Baseline SO2 emissions = 5,066 tpy • 2012 CSAPR allocations = 508 tpy		• The wet lime control systems on G01 and G02 appear to be capable of reducing SO2 emissions below each units' 2014 CSAPR allocations. • Baseline SO2 emissions from units H01 and H02 need to be reduced from a baseline rate of approximately 0.40 lb/MMBtu to a controlled rate of approximately 0.20 lb/MMBtu to meet the 2014 CSAPR allocations • Baseline SO2 from Unit R01 need to be reduced from a baseline rate of 4.52 lb/MMBtu to a controlled rate of 0.20 lb/MMBtu to meet its 2014 CSAPR allocations.		

Rule		CAIR / Tailoring Rule	Cross-State Air Pollution Rule (CSAPR)			Utility MACT	NAAQS/CSAPR Phase II
Compliance Timeframe		**2010/2011**	**2012**	**2013**	**2014**	**2015**	**2016 – 2018**
NOx	Systemwide	• Total NOx emissions from the BREC units need to be reduced by approximately 3.4% to match the CAIR NOx allocations. Relatively small NOx emission reductions on the Coleman Units (from a baseline rate of 0.33 lb/MMBtu to a controlled rate of 0.28 lb/MMBtu) could provide the emisison reductions needed to meet the CAIR NOx allowance requirements.	• Total NOx emissions from the BREC units need to be reduced by approximately 16% to match the CSAPR NOx allocations. • NOx emissions from Units W01, H01 and H02 (equipped with SCR) will remain below the CSAPR allocations, and generate surplus allocations that can be used to offset excess NOx emissions from the other units.			There are no Utility MACT-related NOx emission requirements.	• Assuming the Phase II CSAPR NOx allocations are 20% below the Phase I allocations, total NOx emissions from the BREC units will exceed the Phase II CSAPR allocations. • Baseline annual NOx emissions = 12,074 tpy. • Projected Phase II CSAPR Annual NOx Allocations = 8,114 tons. Average NOx emissions from all BREC generating units need to be reduced to an average controlled NOx emission rate of approximately 0.12 lb/MMBtu to meet the projected Phase II allocations.
	Coleman	• NOx emissions from the Coleman units are approximately 50% above the facility's CAIR NOx allocations. • NOx emissions from the Coleman units need to be reduced from a baseline rate of 0.33 lb/MMBtu to a controlled rate of 0.17 lb/MMBtu to meet the facility's CAIR NOx allocations. • Surplus allowances from Units W01, H01, and H02 (equipped with SCR) can be used to offset excess NOx emissions from the Coleman units.	• NOx emissions from the Coleman units are approximately 53% above the projected CSAPR allocations. • Baseline annual NOx emissions = 5,487 tpy. • Annual CSAPR NOx allocations = 2,581 tpy • NOx emissions from the Coleman units need to be reduced from a baseline rate of 0.33 lb/MMBtu to a controlled rate of 0.16 lb/MMBtu to meet the facility's CSAPR annual and seasonal NOx allocations.				
	Wilson	• NOx emissions from Unit W01 (equipped with SCR) are below the unit's CAIR annual and seasonal NOx allocations. • Surplus allocations from W01 can be used to offset excess NOx emsisions from the Coleman and Green units.	• NOx emissions from Unit W01 (equipped with SCR) will be below the projected annual & seasonal CSAPR allocations. • Surplus NOx allocations from W01 can be used to offset excess NOx emissions from the Coleman and Green Units.				
	Sebree	• NOx emissions from Units H01 and H02 (equipped with SCR) are below the units' CAIR annual and seasonal NOx allocations. • NOx emissions from G01, G02, and R01 are above the CAIR NOx allocations. • NOx emissions from Units G01 and G02 need to be reduced from a baseline rate of 0.21 lb/MMBtu to a controlled rate of 0.16 lb/MMBtu to meet the CAIR NOx allocations. • NOx emissions from Unit R01 need to be reduced from a baseline rate of 0.52 lb/MMBtu to a controlled rate of 0.38 lb/MMBtu to meet the unit's CAIR NOx allocations. • Surplus allocations from Units W01, H01, and H02 can be used to offset excess NOx emissions from the Green and Reid units.	• NOx emissions from Units H01 and H02 (equipped with SCR) will be below the projected annual & seasonal CSAPR allocations. • NOx emissions from Units G01 and G02 are approximately 31% above the projected CSAPR NOx allocations. • NOx emissions from Units G01 and G02 need to be reduced from a baseline rate of 0.21 lb/MMBtu to a controlled rate of approximately 0.14 lb/MMBtu to match the units' CSAPR NOx allocatons. • NOx emissions from Unit R01 are approximately 69% above the projected CSAPR NOx allocations. • NOx emissions from Unit R01 need to be reduced from a baseline rate of 0.52 lb/MMBtu to a controlled rate of approximately 0.16 lb/MMBtu to match the unit's CSAPR NOx allocations. • Surplus allocations from Units W01, H01, and H02 can be used to offset excess NOx emissions from the Green and Reid units.				

Rule		CAIR / Tailoring Rule	Cross-State Air Pollution Rule (CSAPR)			Utility MACT	NAAQS/CSAPR Phase II
Compliance Timeframe		**2010/2011**	**2012**	**2013**	**2014**	**2015**	**2016 – 2018**
Hg	Coleman	No Hg requirements with CAIR	No Hg CSAPR Requirements			• Hg emissions from the Coleman Units (ESP+FGD) are above the proposed MACT limit (3.5 lb/TBtu vs. 1.2 lb/TBtu). The next phase of this project will evalute technolgoies and operating measures capable of increasing mercury oxidation and capture the ESP/FGD, as well as strategies to reduce mercury re-emissions in the FGD.	No Hg CSAPR Requirements
	Wilson					• Hg emissions from Unit W01 (SCR+ESP+FGD) are above the proposed MACT limit (1.77 lb/TBtu vs. 1.2 lb/TBtu). The next phase of this project will evalute technolgoies and operating measures capable of increasing mercury oxidation and capture the ESP/FGD, as well as strategies to reduce mercury re-emissions in the FGD.	
	Sebree					• Hg emissions from Units H01 & H02 (SCR+ESP+FGD) are below the proposed MACT limit. • Hg emissions from Units G01, G02, and R01 appear to be above the proposed MACT limit. The next phase of this project will evalute technolgoies and operating measures capable of increasing mercury oxidation and capture the ESP/FGD, as well as strategies to reduce mercury re-emissions in the FGD.	
Acid Gases (HCl or SO2)	Coleman	No Acid Gas requirements with CAIR	No Acid Gas CSAPR Requirements			• Existing SO2 emissions from the Coleman Units exceed the proposed MACT limit (0.25 lb/MMBtu vs. 0.20 lb/MMBtu). • Exisitng HCl emisisons are less than the proposed MACT limit. • The next phase of this project will evalute FGD upgrades and modifications to achieve a controlled SO2 emission rate of 0.20 lb/MMBtu (30-day average)	No Acid Gas CSAPR Requirements
	Wilson					• Exisitng SO2 emissions from W01 exeed the proposed MACT limit (0.41 lb/MMBtu vs. 0.20 lb/MMBtu). • Existiing HCl emisison are less than the proposed MACT limit. • Evaluate FGD modifications/upgrades to achieve a controlled SO2 emission rate of 0.20 lb/MMBtu (30-day average).	
	Sebree					• Existing SO2 emissions from G01 & G02 are below the proposed MACT limit. • Existing SO2 emissions from H01 & H02 exceed the proposed MACT limit (0.38 lb/MMBtu vs. 0.20 lb/MMBtu). • Existing HCl emissions from the Green and HMP&L units are less than the proposed MACT limit. • Evalunte FGD modifications/upgrades to achieve a controlled SO2 emission rate of 0.20 lb/MMBtu (30-day average) on the HMP&L units. • Unlikely that Unit R01 can meet the proposed MACT acid gas standards without achieving significant SO2/HCl emission reductions.	
TPM or non-HG Metals	Coleman	No Trace Metal / TPM requirements with CAIR	No Trace Metal / TPM CSAPR Requirements			• Existing TPM emissions are 33% above the proposed MACT limit. • Evaluate potential ESP upgrades.	No Trace Metal / TPM CSAPR Requirements
	Wilson					• Existing TPM emissions are below the proposed MACT limit. • Modification may be required with the addition of ACI or DSI.	
	Sebree					• Existing TPM emissions from Units H01 & H02 are approximately 7% above the proposed MACT limit primarily due to SO2 to SO3 oxidation across the SCR. • The next phase of this project will evalaute potential CPM control technologies for Units H01 & H02. • Existing TPM emissions from Units G01 & G02 are below the proposed MACT limit; however, modifications may be required with the addition of ACI or DSI. • Existing TPM emissiosn from Unit R01 are likely above the proposed MACT limit. Evaluate technologies capable of reducing FPM emissions from R01, inlcuding FGD upgrades.	
Greenhouse Gases	*All Units*	*Modifications that result in a significant net increase in GHG emissions will be subject to NSR-PSD preconstruction review and permitting.*					

Appendix 5 – Additional Expanded Compliance Strategy Matrices

Technology Selection & Results - Strategy 1

BREC Unit	Technology Selection: CSAPR - Selection SO_2	CSAPR - Selection NO_x	MACT - Selection HCl	MACT - Selection Hg	MACT - Selection CPM	MACT - Selection FPM	Emission Surplus / (Deficit) vs. Allocation: CSAPR II - 2014 (Tons) SO_2	CSAPR II - 2014 (Tons) NO_x	Projected NAAQS (Tons) SO_2	Projected NAAQS (Tons) NO_x
Coleman Unit C01	None**	None	HCl level is below anticipated MACT limits. Installation of an HCl monitor is needed since SO2 can not be used as a surrogate.***	Fuel Additive & Activated Carbon Injection or Activated Carbon Injection	Hydrated Lime - DSI	Advanced Electrodes & High Frequency TR Sets	(323)	(1017)	(553)	(1185)
Coleman Unit C02	None**	None	HCl level is below anticipated MACT limits. Installation of an HCl monitor is needed since SO2 can not be used as a surrogate.***	Fuel Additive & Activated Carbon Injection or Activated Carbon Injection	Hydrated Lime - DSI	Advanced Electrodes & High Frequency TR Sets	(323)	(743)	(553)	(912)
Coleman Unit C03	None**	None	HCl level is below anticipated MACT limits. Installation of an HCl monitor is needed since SO2 can not be used as a surrogate.***	Fuel Additive & Activated Carbon Injection or Activated Carbon Injection	Hydrated Lime - DSI	Advanced Electrodes & High Frequency TR Sets	(345)	(1146)	(590)	(1326)
Wilson Unit W01	New Tower Scrubber - 99% removal	None	Higher L/G or new tower for increased SO2 removal to below 0.2 lb/mmBtu will permit reporting SO2 data as prima facia evidence of compliance with HCl emission limits	Activated Carbon Injection & New SCR Catalyst	Low Oxidation SCR catalyst + Hydrated Lime - DSI	Advanced Electrodes & High Frequency TR Sets	2565	1711	1843	1182
Green Unit G01	None	SCR@85% Removal	HCl Montior is not required since SO2 is below 0.2 lb/mmBtu	Activated Carbon Injection	Hydrated Lime - DSI	Potential ESP Upgrades Due to ACI and DSI	91	1130	(302)	842
Green Unit G02	None	SCR@85% Removal	HCl Montior is not required since SO2 is below 0.2 lb/mmBtu	Activated Carbon Injection	Hydrated Lime - DSI	Potential ESP Upgrades Due to ACI and DSI	357	1128	3	837
HMP&L Unit H01	Run both pumps & spray levels, install 3rd pump as spare	None	Higher L/G for increased SO2 removal to below 0.2 lb/mmBtu will permit reporting SO2 data as prima facia evidence of compliance with HCl emission limits	None needed due to oxidation across SCR and WFGD	Low Oxidation SCR catalyst + Hydrated Lime - DSI Control NH3 slip from SCR	ESP Maintenance / Possible Upgrade	463	456	213	273
HMP&L Unit H02	Run both pumps & spray levels, install 3rd pump as spare	None	Higher L/G for increased SO2 removal to below 0.2 lb/mmBtu will permit reporting SO2 data as prima facia evidence of compliance with HCl emission limits	None needed due to oxidation across SCR and WFGD	Low Oxidation SCR catalyst + Hydrated Lime - DSI Control NH3 slip from SCR	ESP Maintenance / Possible Upgrade	454	526	196	337
Reid Unit R01*	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	218	(132)	174	(164)
Reid Unit RT	None	None	None	None	None	None	4	(39)	2	(40)
TOTAL							3161	1873	432	(155)

BREC Unit	Capital Cost (Millions $) SO_2	NO_x	HCl	Hg	CPM	FPM	Total Projected Capital Cost (2011$)	Additional O&M Cost (Millions $) SO_2	NO_x	HCl	Hg	CPM	FPM	Fuel Cost Increase (2011$)	Total Yearly O&M Cost Increase (2011$)
Coleman Unit C01	0.00	0.00	0.32	4.00	5.00	2.72	$12,000,000	0.00	0.00	0.03	0.81	0.27	0.09		$1,200,000
Coleman Unit C02	0.00	0.00	0.32	4.00	5.00	2.72	$12,000,000	0.00	0.00	0.03	0.81	0.27	0.09		$1,200,000
Coleman Unit C03	0.00	0.00	0.32	4.00	5.00	2.72	$12,000,000	0.00	0.00	0.03	0.81	0.27	0.09		$1,200,000
Wilson Unit W01	139.00	0.00	0.00	4.50	6.50	4.54	$154,500,000	0.69	0.00	0.00	2.19	0.00	0.17		$3,100,000
Green Unit G01	0.00	81.00	0.00	4.00	5.00	3.34	$93,300,000	0.00	2.16	0.00	1.14	0.32	0.07		$3,700,000
Green Unit G02	0.00	81.00	0.00	4.00	5.00	3.34	$93,300,000	0.00	2.16	0.00	1.14	0.32	0.07		$3,700,000
HMP&L Unit H01	3.15	0.00	0.00	0.00	6.00	2.50	$11,700,000	0.38	0.00	0.00	0.00	0.29	0.08		$800,000
HMP&L Unit H02	3.15	0.00	0.00	0.00	6.00	2.50	$11,700,000	0.38	0.00	0.00	0.00	0.29	0.08		$800,000
Reid Unit R01*	1.20						$1,200,000	(1.77)						$5,610,000	$3,800,000
Reid Unit RT	0.00						$0	0.00							$0
TOTAL							$402,000,000							$5,610,000	$19,500,000

*Note O&M savings associated with reduced maintenance and operational labor/parts have been extimated based on S&L expience due to lack of available operational data.

**Note SO2 emissions in this scenario have been adjusted to reflect recent data received from BREC confirming that the Coleman FGD is capable of producing emission rates of 0.25lb/MMBtu and reaching removal rates of approximately 95%.

***Note four (4) HCl monitors are required for Coleman. One (1) for the common WFGD stack and one (1) for each unit bypass stack.

Technology Selection & Results - Strategy 2

	Technology Selection						Emission Surplus / (Deficit) vs. Allocation				Capital Cost (Millions $)						Total Projected Capital Cost (2011$)	Additional O&M Cost (Millions $)						Fuel Cost Increase (2011$)	Total Yearly O&M Cost Increase (2011$)
	CSAPR - Selection		MACT - Selection				CSAPR II - 2014 (Tons)		Projected NAAQS (Tons)																
BREC Unit	SO_2	NO_x	HCl	Hg	CPM	FPM	SO_2	NO_x	SO_2	NO_x	SO_2	NO_x	HCl	Hg	CPM	FPM		SO_2	NO_x	HCl	Hg	CPM	FPM		
Coleman Unit C01	None**	SNCR@20% Removal	HCl level is below anticipated MACT limits. Installation of an HCl monitor is needed since SO2 can not be used as a surrogate.***	Fuel Additive & Activated Carbon Injection or Activated Carbon Injection	Hydrated Lime - DSI Control NH3 slip from ROTOMIX	Advanced Electrodes & High Frequency TR Sets	(323)	(646)	(553)	(814)	0.00	2.40	0.32	4.00	5.00	2.72	$14,400,000	0.00	1.56	0.03	0.81	0.27	0.09		$2,700,000
Coleman Unit C02	None**	SNCR@20% Removal	HCl level is below anticipated MACT limits. Installation of an HCl monitor is needed since SO2 can not be used as a surrogate.***	Fuel Additive & Activated Carbon Injection or Activated Carbon Injection	Hydrated Lime - DSI Control NH3 slip from SNCR	Advanced Electrodes & High Frequency TR Sets	(323)	(426)	(553)	(595)	0.00	2.70	0.32	4.00	5.00	2.72	$14,700,000	0.00	1.58	0.03	0.81	0.27	0.09		$2,800,000
Coleman Unit C03	None**	SNCR@20% Removal	HCl level is below anticipated MACT limits. Installation of an HCl monitor is needed since SO2 can not be used as a surrogate.***	Fuel Additive & Activated Carbon Injection or Activated Carbon Injection	Hydrated Lime - DSI Control NH3 slip from SNCR	Advanced Electrodes & High Frequency TR Sets	(345)	(737)	(590)	(917)	0.00	2.70	0.32	4.00	5.00	2.72	$14,700,000	0.00	1.58	0.03	0.81	0.27	0.09		$2,800,000
Wilson Unit W01	New Tower Scrubber - 99% removal	None	Higher L/G or new tower for increased SO2 removal to below 0.2 lb/mmBtu will permit reporting SO2 data as prima facia evidence of compliance with HCl emission limits	Activated Carbon Injection & New SCR Catalyst	Low Oxidation SCR catalyst + Hydrated Lime - DSI	Advanced Electrodes & High Frequency TR Sets	2565	1711	1843	1182	139.00	0.00	0.00	4.50	6.50	4.54	$154,500,000	0.69	0.00	0.00	2.19	0.00	0.17		$3,100,000
Green Unit G01	None	SCR@85% Removal	HCl Montior is not required since SO2 is below 0.2 lb/mmBtu	Activated Carbon Injection	Hydrated Lime - DSI	Potential ESP Upgrades Due to ACI and DSI	91	1130	(302)	842	0.00	81.00	0.00	4.00	5.00	3.34	$93,300,000	0.00	2.16	0.00	1.14	0.32	0.07		$3,700,000
Green Unit G02	None	SCR@85% Removal	HCl Montior is not required since SO2 is below 0.2 lb/mmBtu	Activated Carbon Injection	Hydrated Lime - DSI	Potential ESP Upgrades Due to ACI and DSI	357	1128	3	837	0.00	81.00	0.00	4.00	5.00	3.34	$93,300,000	0.00	2.16	0.00	1.14	0.32	0.07		$3,700,000
HMP&L Unit H01	Run both pumps & spray levels, install 3rd pump as spare	None	Higher L/G for increased SO2 removal to below 0.2 lb/mmBtu will permit reporting SO2 data as prima facia evidence of compliance with HCl emission limits	None needed due to oxidation across SCR and WFGD	Low Oxidation SCR catalyst + Hydrated Lime - DSI Control NH3 slip from SCR	ESP Maintenance / Possible Upgrade	463	456	213	273	3.15	0.00	0.00	0.00	6.00	2.50	$11,700,000	0.38	0.00	0.00	0.00	0.29	0.08		$800,000
HMP&L Unit H02	Run both pumps & spray levels, install 3rd pump as spare	None	Higher L/G for increased SO2 removal to below 0.2 lb/mmBtu will permit reporting SO2 data as prima facia evidence of compliance with HCl emission limits	None needed due to oxidation across SCR and WFGD	Low Oxidation SCR catalyst + Hydrated Lime - DSI Control NH3 slip from SCR	ESP Maintenance / Possible Upgrade	454	526	196	337	3.15	0.00	0.00	0.00	6.00	2.50	$11,700,000	0.38	0.00	0.00	0.00	0.29	0.08		$800,000
Reid Unit R01*	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	218	(132)	174	(164)	1.20						$1,200,000	(1.77)						$5,610,000	$3,800,000
Reid Unit RT	None	None	None	None	None	None	4	(39)	2	(40)	0.00						$0	0.00							$0
TOTAL							3161	2971	432	943							$410,000,000							$5,610,000	$24,200,000

*Note O&M savings associated with reduced maintenance and operational labor/parts have been extimated based on S&L expience due to lack of available operational data.
**Note SO2 emissions in this scenario have been adjusted to reflect recent data received from BREC confirming that the Coleman FGD is capable of producing emission rates of 0.25lb/MMBtu and reaching removal rates of approximately 95%.
***Note four (4) HCl monitors are required for Coleman. One (1) for the common WFGD stack and one (1) for each unit bypass stack.

Technology Selection & Results - Strategy 3

BREC Unit	Technology Selection: CSAPR - Selection: SO_2	CSAPR - Selection: NO_x	MACT - Selection: HCl	MACT - Selection: Hg	MACT - Selection: CPM	MACT - Selection: FPM
Coleman Unit C01	None**	SNCR@20% Removal	HCl level is below anticipated MACT limits. Installation of an HCl monitor is needed since SO2 can not be used as a surrogate.***	Fuel Additive & Activated Carbon Injection or Activated Carbon Injection	Hydrated Lime - DSI Control NH3 slip from ROTOMIX	Advanced Electrodes & High Frequency TR Sets
Coleman Unit C02	None**	SNCR@20% Removal	HCl level is below anticipated MACT limits. Installation of an HCl monitor is needed since SO2 can not be used as a surrogate.***	Fuel Additive & Activated Carbon Injection or Activated Carbon Injection	Hydrated Lime - DSI Control NH3 slip from SNCR	Advanced Electrodes & High Frequency TR Sets
Coleman Unit C03	None**	SNCR@20% Removal	HCl level is below anticipated MACT limits. Installation of an HCl monitor is needed since SO2 can not be used as a surrogate.***	Fuel Additive & Activated Carbon Injection or Activated Carbon Injection	Hydrated Lime - DSI Control NH3 slip from SNCR	Advanced Electrodes & High Frequency TR Sets
Wilson Unit W01	New Tower Scrubber - 99% removal	None	Higher L/G or new tower for increased SO2 removal to below 0.2 lb/mmBtu will permit reporting SO2 data as prima facia evidence of compliance with HCl emission limits	Activated Carbon Injection & New SCR Catalyst	Low Oxidation SCR catalyst + Hydrated Lime - DSI	Advanced Electrodes & High Frequency TR Sets
Green Unit G01	None	SCR@85% Removal	HCl Monitor is not required since SO2 is below 0.2 lb/mmBtu	Activated Carbon Injection	Hydrated Lime - DSI	Potential ESP Upgrades Due to ACI and DSI
Green Unit G02*	Switch to Natural Gas w/FGR	Switch to Natural Gas w/FGR	None	None	None	None
HMP&L Unit H01	Run both pumps & spray levels, install 3rd pump as spare	None	Higher L/G for increased SO2 removal to below 0.2 lb/mmBtu will permit reporting SO2 data as prima facia evidence of compliance with HCl emission limits	None needed due to oxidation across SCR and WFGD	Low Oxidation SCR catalyst + Hydrated Lime - DSI Control NH3 slip from SCR	ESP Maintenance / Possible Upgrade
HMP&L Unit H02	Run both pumps & spray levels, install 3rd pump as spare	None	Higher L/G for increased SO2 removal to below 0.2 lb/mmBtu will permit reporting SO2 data as prima facia evidence of compliance with HCl emission limits	None needed due to oxidation across SCR and WFGD	Low Oxidation SCR catalyst + Hydrated Lime - DSI Control NH3 slip from SCR	ESP Maintenance / Possible Upgrade
Reid Unit R01*	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners
Reid Unit RT	None	None	None	None	None	None
TOTAL						

BREC Unit	Emission Surplus / (Deficit) vs. Allocation: CSAPR II - 2014 (Tons) SO_2	CSAPR II - 2014 (Tons) NO_x	Projected NAAQS (Tons) SO_2	Projected NAAQS (Tons) NO_x	Capital Cost (Millions $): SO_2	NO_x	HCl	Hg	CPM	FPM	Total Projected Capital Cost (2011$)	Additional O&M Cost (Millions $): SO_2	NO_x	HCl	Hg	CPM	FPM	Fuel Cost Increase (2011$)	Total Yearly O&M Cost Increase (2011$)
Coleman Unit C01	(323)	(646)	(553)	(814)	0.00	2.40	0.32	4.00	5.00	2.72	$14,400,000	0.00	1.56	0.03	0.81	0.27	0.09		$2,700,000
Coleman Unit C02	(323)	(426)	(553)	(595)	0.00	2.70	0.32	4.00	5.00	2.72	$14,700,000	0.00	1.58	0.03	0.81	0.27	0.09		$2,800,000
Coleman Unit C03	(345)	(737)	(590)	(917)	0.00	2.70	0.32	4.00	5.00	2.72	$14,700,000	0.00	1.58	0.03	0.81	0.27	0.09		$2,800,000
Wilson Unit W01	2565	1711	1643	1182	139.00	0.00	0.00	4.50	6.50	4.54	$154,500,000	0.69	0.00	0.00	2.19	0.00	0.17		$3,100,000
Green Unit G01	91	1130	(302)	842	0.00	81.00	0.00	4.00	5.00	3.34	$93,300,000	0.00	2.16	0.00	1.14	0.32	0.07		$3,700,000
Green Unit G02*	1768	288	1414	(3)	25.60						$25,600,000	(3.74)						$50,930,000	$47,200,000
HMP&L Unit H01	463	458	213	273	3.15	0.00	0.00	0.00	6.00	2.50	$11,700,000	0.38	0.00	0.00	0.00	0.29	0.08		$800,000
HMP&L Unit H02	454	526	196	337	3.15	0.00	0.00	0.00	6.00	2.50	$11,700,000	0.38	0.00	0.00	0.00	0.29	0.08		$800,000
Reid Unit R01*	218	(132)	174	(164)	1.20						$1,200,000	(1.77)						$5,610,000	$3,600,000
Reid Unit RT	4	(39)	2	(40)	0.00						$0	0.00							$0
TOTAL	4571	2131	1843	102							$342,000,000							$56,540,000	$67,700,000

*Note O&M savings associated with reduced maintenance and operational labor/parts have been extimated based on S&L exprence due to lack of available operational data.
**Note SO2 emissions in this scenario have been adjusted to reflect recent data received from BREC confirming that the Coleman FGD is capable of producing emission rates of 0.25lb/MMBtu and reaching removal rates of approximately 95%.
***Note four (4) HCl monitors are required for Coleman. One (1) for the common WFGD stack and one (1) for each unit bypass stack.

Technology Selection & Results - Strategy 4

BREC Unit	Technology Selection						Emission Surplus / (Deficit) vs. Allocation				Capital Cost (Millions $)						Total Projected Capital Cost (2011$)	Additional O&M Cost (Millions $)						Fuel Cost Increase (2011$)	Total Yearly O&M Cost Increase (2011$)
	CSAPR - Selection		MACT - Selection				CSAPR II - 2014 (Tons)		Projected NAAQS (Tons)																
	SO_2	NO_x	HCl	Hg	CPM	FPM	SO_2	NO_x	SO_2	NO_x	SO_2	NO_x	HCl	Hg	CPM	FPM		SO_2	NO_x	HCl	Hg	CPM	FPM		
Coleman Unit C01	None**	SNCR@20% Removal	HCl level is below anticipated MACT limits. Installation of an HCl monitor is needed since SO2 can not be used as a surrogate.***	Fuel Additive & Activated Carbon Injection or Activated Carbon Injection	Fuel Additive & Activated Carbon Injection or Activated Carbon Injection	Advanced Electrodes & High Frequency TR Sets	(323)	(646)	(553)	(814)	0.00	2.40	0.32	4.00		2.72	$9,400,000	0.00	1.56	0.03	0.81		0.09		$2,500,000
Coleman Unit C02	None**	SNCR@20% Removal	HCl level is below anticipated MACT limits. Installation of an HCl monitor is needed since SO2 can not be used as a surrogate.***	Fuel Additive & Activated Carbon Injection or Activated Carbon Injection	Fuel Additive & Activated Carbon Injection or Activated Carbon Injection	Advanced Electrodes & High Frequency TR Sets	(323)	(426)	(553)	(595)	0.00	2.70	0.32	4.00		2.72	$9,700,000	0.00	1.58	0.03	0.81		0.09		$2,500,000
Coleman Unit C03	None**	SNCR@20% Removal	HCl level is below anticipated MACT limits. Installation of an HCl monitor is needed since SO2 can not be used as a surrogate.***	Fuel Additive & Activated Carbon Injection or Activated Carbon Injection	Fuel Additive & Activated Carbon Injection or Activated Carbon Injection	Advanced Electrodes & High Frequency TR Sets	(345)	(737)	(590)	(917)	0.00	2.70	0.32	4.00		2.72	$9,700,000	0.00	1.58	0.03	0.81		0.09		$2,500,000
Wilson Unit W01	New Tower Scrubber - 99% removal	None	Higher L/G or new tower for increased SO2 removal to below 0.2 lb/mmBtu will permit reporting SO2 data as prima facia evidence of compliance with HCl emission limits	Activated Carbon Injection & New SCR Catalyst	Activated Carbon Injection & New SCR Catalyst	Advanced Electrodes & High Frequency TR Sets	2565	1711	1843	1182	139.00	0.00	0.00	4.50	6.50	4.54	$154,500,000	0.69	0.00	0.00	2.19	0.00	0.17		$3,100,000
Green Unit G01*	Switch to Natural Gas wFGR	Switch to Natural Gas wFGR	None	None	None	None	1961	202	1568	(86)	27.55						$27,600,000	(3.74)						$50,380,000	$46,600,000
Green Unit G02*	Switch to Natural Gas wFGR	Switch to Natural Gas wFGR	None	None	None	None	1768	268	1414	(3)	27.55						$27,600,000	(3.74)						$50,930,000	$47,200,000
HMP&L Unit H01	Run both pumps & spray levels, install 3rd pump as spare	None	Higher L/G for increased SO2 removal to below 0.2 lb/mmBtu will permit reporting SO2 data as prima facia evidence of compliance with	None needed due to oxidation across SCR and WFGD	Low Oxidation SCR catalyst + Hydrated Lime - DSI Control NH3 slip from	ESP Maintenance / Possible Upgrade	463	456	213	273	3.15	0.00	0.00	0.00	6.00	2.50	$11,700,000	0.38	0.00	0.00	0.00	0.29	0.08		$800,000
HMP&L Unit H02	Run both pumps & spray levels, install 3rd pump as spare	None	Higher L/G for increased SO2 removal to below 0.2 lb/mmBtu will permit reporting SO2 data as prima facia evidence of compliance with HCl emission limits	None needed due to oxidation across SCR and WFGD	Low Oxidation SCR catalyst + Hydrated Lime - DSI Control NH3 slip from SCR	ESP Maintenance / Possible Upgrade	454	526	196	337	3.15	0.00	0.00	0.00	6.00	2.50	$11,700,000	0.38	0.00	0.00	0.00	0.29	0.08		$800,000
Reid Unit R01*	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	218	(132)	174	(164)	1.20						$1,200,000	(1.77)						$5,610,000	$3,800,000
Reid Unit RT	None	None	None	None	None	None	4	(39)	2	(40)	0.00						$0	0.00							$0
TOTAL							6442	1203	3713	(825)							$264,000,000							$106,920,000	$109,800,000

*Note O&M savings associated with reduced maintenance and operational labor/parts have been extimated based on S&L exprence due to lack of available operational data.
**Note SO2 emissions in this scenario have been adjusted to reflect recent data received from BREC confirming that the Coleman FGD is capable of producing emission rates of 0.25lb/MMBtu and reaching removal rates of approximately 95%.
***Note four (4) HCl monitors are required for Coleman. One (1) for the common WFGD stack and one (1) for each unit bypass stack.

Case No. 2012-00063
Exhibit DePriest-3 – S&L Study Supplemental: Final MACT Rule

ESP Performance Based on Final MACT Rule

Sargent & Lundy prepared an environmental compliance study for Big Rivers Electric Corporation (BREC) in which ESP upgrades were recommended on several units to address some of the emissions requirements in the proposed Utility MACT rule. In part, the proposed rule allowed existing units to demonstrate compliance with non-mercury hazardous air pollutant (HAP) metal emissions limits in one of three ways:

- By emitting less than 0.03 lb/MMBtu of total particulate matter (TPM), which included condensable particulates as well as filterable particulates.
- By emitting less than 0.00004 lb/MMBtu of total non-Hg HAP metals.
- By emitting less than the individual non-Hg HAP metal limits established for each constituent.

Stack test data taken at Green 1 and 2, HMP&L 1 and 2, and Coleman 1, 2, and 3 indicated that baseline emissions of the total non-Hg HAP metals and the individual non-Hg metals were above the proposed MACT emission limits. However, TPM emissions from the Green and Wilson units were below the proposed TPM MACT emission limit. S&L's study report concluded that ESP upgrades would not be required to improve particulate removal for Wilson and Green because their emissions were far under the TPM limit. However, upgrades were recommended for Coleman and HMP&L stations to improve particulate removal.

Subsequent to S&L's report, the U.S. EPA issued the final rule, referred to as the Mercury and Air Toxics Standards ("MATS Rule" aka "Utility MACT Rule). The final rule still requires existing units to demonstrate compliance with a non-Hg HAP metals emission limit, and still provides the opportunity to demonstrate non-Hg metals compliance via the three methods in proposed rule. However, the final rule included a significant change in that condensable particulates were no longer included in the PM emission requirement. In fact, the final rule includes an emission limit of 0.03 lb/MMBtu of filterable particulate matter (FPM) only to act as a surrogate for demonstrating non-Hg HAP metal compliance. Therefore, the final emission limit is less stringent than the proposed limit because it removed the condensable portion while keeping the emission limit value the same.

Table 1 summarizes the particulate test data that was used in the original Sargent & Lundy report. The test data indicate that all plants are currently below the FPM limit. Therefore, to comply with the FPM requirement, no ESP upgrades, in addition to what BREC has already implemented, would be required. Although, to achieve the mercury emission limit, sorbents will need to be injected, which may affect ESP performance as discussed below.

Table 1: Summary of Particulate Test Results at BREC Units

	Green 1	Green 2	HMP&L 1	HMP&L 2	Coleman	Wilson - Coal	Wilson - Petcoke
Filterable PM	**0.00843**	**0.00455**	**0.0177**	**0.0120**	**0.0220**	**0.00912**	**0.0142**
Condensable PM	0.0111	0.0123	0.0142	0.0204	0.0178	0.01043	0.00978
Total PM	0.0195	0.0169	0.0319	0.0324	0.0398	0.0196	0.024

ESP Performance Based on Final MACT Rule

It's important to note that the original basis of recommending dry sorbent injection (DSI) was primarily to address condensable particulate emissions to ensure compliance with the proposed TPM emission limit. However, S&L anticipates DSI would still be needed wherever activated carbon is implemented for Hg control to reduce SO_3 concentrations in the flue gas. SO_3 competes with Hg on activated carbon. For units firing bituminous fuels, if sorbent injection is not included, activated carbon injection rates can be very high, and the mercury removal efficiencies may be limited even at very high injection rates. Sorbents are much lower in cost than carbon; therefore, implementing dry sorbent injection in conjunction with ACI will significantly improve variable O&M costs associated with carbon. As the original study states, if DSI and ACI systems are required to meet mercury compliance, it is possible that some ESP performance improvements would need to be made to accommodate a higher particulate loading at the ESP inlet. Therefore, testing with sorbent and carbon injection is recommended, especially at Coleman station, which is the closest to the MATS FPM limit.

In general, S&L believes that the BREC ESPs in their current condition can meet the MATS FPM emission limit because of the following reasons:

- There is margin between the FPM limits and the existing emission rates indicated in Table 1.
- Using sodium -based sorbents to remove SO_3 is known to lower ash resistivity and aid in collection efficiencies, even though the total particulate loading is higher.
- Each of the BREC units are followed by wet FGD systems that may aid in FPM collection, depending on the particulate size.

To address any remaining concerns that BREC may have regarding their ESP performance, Sargent & Lundy has the capability of modeling ESP performance. S&L would develop a computer-based model of the ESPs based on design information and recent operating and performance data. The model would be calibrated with recent stack test data in order to benchmark the results. This model can then be used to predict ESP performance once ACI and/or DSI are implemented. The results of an ESP modeling study could refine recommendation with regard to additional ESP modifications based on the final MATS rule; however, S&L still recommends testing of ACI and DSI at each unit to finalize the impacts that these systems will have on ESP performance.

Case No. 2012-00063
Exhibit DePriest-4 – S&L Study Supplemental: Fuel Switching

Fuel Switching for CSAPR Compliance

Sargent & Lundy prepared an environmental compliance study for Big Rivers Electric Corporation (BREC) in which the following technologies were recommended to address compliance with the final CSAPR rule:

- At Wilson Unit 1, to help meet SO_2 compliance, a new FGD absorber designed to achieve 99% removal of SO_2.
- At HMP&L Units 1 and 2, to help meet SO_2 compliance, it was recommended that both spray levels be put in operation and that a third pump be installed as a spare.
- At Green Unit 2, to help meet NO_x compliance, a new SCR system designed to achieve 0.05 lb/MMBtu NO_x emissions.

As part of Sargent & Lundy's study, fuel switching to fire Powder River Basin (PRB) fuel at these units was initially considered as a viable approach to achieving SO_2 and NOx compliance with CSAPR; however, it was quickly eliminated due to the extremely high net present value (NPV). The NPV was determined using the same economic parameters that were utilized in the Big Rivers environmental compliance report.

Generally speaking, there are two main cost components to convert bituminous units to PRB units. One cost component is to address the safety issues (fire and explosion) that are associated with handling of PRB fuel. The second cost component is to address performance issues.

Fire and Explosion Issues Associated with PRB Conversions

PRB coals have unique characteristics that make them more of a fire and explosion hazard than other coals. PRB coal is more friable (breakable); that is, it fractures more easily, producing a high percentage of fines. The greater friability increases the potential for dust formation. PRB coals also tend to spontaneously combust because of high methane content. Because of the potential for personnel injury and the potential costs associated with equipment or unit availability, additional fire protection and dust control provisions should be included when planning a conversion to PRB coal.

Fire and explosion issues associated with PRB conversions are expected to be mitigated with the following approaches:

- Dust Control
- Ventilation
- Housekeeping
- Electrical Requirements
- Fire Protection
- Operation and maintenance Procedures

Dust Control

One way of reducing the risk of fire and explosion with PRB coal is increased control of coal dust. Coal dust control is required at locations where dust is generated, specifically coal conveyor transfer points that discharge onto other conveyors, surge bins, bunkers, or other equipment.

Another way of reducing the risk associated with PRB dust is to reduce how much dust is generated. This can be achieved through several means, including:

- Lower conveyor belt speeds
- Two-stage belt cleaning systems
- Belt misalignment switches
- Properly designed and maintained loading skirts and dust curtains
- Enhanced coal pile management practices

Ventilation

Enhanced ventilation systems are required in various locations when firing PRB coal. These systems are required to:

- Provide continuous makeup of outdoor air to offset dust collector exhaust
- Provide fresh air ventilation for personnel occupancy
- Pressurize electrical equipment rooms and other areas to minimize dust infiltration
- Reduce and dilute explosive dust concentrations, methane gas buildup, and products of combustion, such as carbon monoxide, from enclosed coal-handling buildings.

Housekeeping

The increased dustiness of PRB coal necessitates more frequent manual wash-down and vacuum cleaning of coal handling areas. A vacuum cleaning system is required for all enclosed coal handling areas and along conveyor galleries.

Horizontal surfaces in coal handling structures require frequent housekeeping, water wash-down and/or vacuuming to minimize the risk of spontaneous combustion. Some horizontal steel members may need to be modified by filling the dust ledges or pockets with lightweight concrete, or using other means to prevent dust from settling in these areas.

Electrical Requirements

Due to the hazardous nature of PRB coal dust, special electrical considerations are required to minimize potential ignition sources. Electrical installations in enclosed areas should be ignition-proof to account for the possibility that sufficient combustible dust is present to produce an explosive or ignitable mixture with air.

Fire Protection

For conversion to PRB coal, expansion of the existing fire protection and detection systems is likely to be required to provide additional coverage. Carbon monoxide detectors should be located in all enclosed coal handling areas with suitable alarms located in the main control room.

Operation and Maintenance Procedures

When converting an existing unit to burn PRB coal after many years of burning another coal, station O&M personnel will be required to undergo training to ensure they understand what procedural changes are required to minimize the potential hazards.

Facilities and Performance Issues Associated with PRB Conversions

In addition to safety concerns, the characteristics of PRB coals impact a power plant's ability to perform in many areas. The key areas that are impacted include:

- Boiler Performance
- Boiler Auxiliaries
- Combustion Air and Flue Gas Equipment

Fuel Switching for CSAPR Compliance

- Electrostatic Precipitators
- Selective Catalytic Reduction (SCR) Systems
- Coal Handling
- Ash Handling
- Makeup Water System
- Wastewater System
- Auxiliary Power Equipment

Boiler Performance
The lower fuel higher heating value (HHV) of PRB coal compared to bituminous coal requires a greater firing rate in the boiler. The higher fuel firing rate can increase the size requirements of the boiler combustion zone and limit capacity. Higher moisture content in PRB coal increase the latent heat of vaporization losses in the boiler and thereby reduces combustion efficiency. PRB coal ash properties tend to increase slagging and fouling in the boiler.

To mitigate the effect on boiler performance, additional equipment or boiler modifications may be required. For example, tilting burners, flue gas recirculation, and attemporation may be needed to control steam temperature when wall slagging is excessive. Additional sootblowers may also be required. The convective heat transfer surfaces need to be reviewed to determine the potential for fouling in these areas. Finned economizer tubes may need to be replaced because of their increased potential to foul.

Boiler Auxiliaries
Pulverizers – The following characteristics of PRB coal have a major impact on pulverizers:

- The higher fuel firing rate requires a higher pulverize capacity.
- Higher moisture content in PRB coal can reduce pulverizer capacity because it causes the coal particles to agglomerate and requires higher mill air inlet temperatures and/or increased residence time to sufficiently dry the coal.
- PRB coal also reduces pulverizer capacity because it is more difficult to pulverize. More power and increased pulverizer residence time (recirculation) are required to reduce the raw coal to the required fineness.

The use of a spare pulverizer, pulverizer system modifications, pulverizer replacement, or additional pulverizers may be required to overcome the reduction in capacity caused by the above factors.

Burners – If the PRB fuel represents a significant reduction in the overall volatile content compared to the existing fuel, modification of the burners or even alteration of the method of firing may be required.

Coal Feeders – The coal feeders may also need to be modified to account for the higher fuel rates required.

Combustion Air and Flue Gas Equipment
Converting to PRB coal will increase the mass flow requirements for the FD, ID, and PA fans, largely resulting from the higher fuel rates required. There is also an associated increase in

Fuel Switching for CSAPR Compliance

developed head requirements and horsepower. Therefore, this equipment may need to be modified or replaced as part of a PRB conversion.

Electrostatic Precipitators (ESPs)
Electrostatic precipitators are used at HMP&L, Green, and Wilson to remove fly ash from the flue gas. Conversion to PRB low-sulfur coal generally reduces the ESP collection efficiency because of changes in flue gas volume, ash content, higher operating temperatures, and fly ash resistivity. Depending on the size and condition of the existing ESPs, ESP modifications may be required to ensure continued compliance with the MATS filterable particulate emission limits at these stations.

SCR System
The existing SCR systems at Wilson and HMP&L are designed for bituminous fuels. PRB fly ash has a significantly higher tendency to plug SCR catalyst and usually requires a larger catalyst pitch than required for bituminous applications. As part of a PRB conversion, the SCR catalyst may need to be replaced to avoid significant plugging issues. In addition, the catalyst cleaning system may need to be redesigned or augmented to increase the cleaning efficiency.

Coal Handling System
The changes required for a coal handling system to accommodate PRB coal are principally due to poor coal flowability caused by high moisture content and reduced capacity due to higher fuel rates. To compensate for these factors, the following modifications are expected:

- Modifying chute valley angles, if possible
- It is often impractical to change the chute valley angles so installing 304 stainless steel liners may be required to enhance flowability
- Increasing hopper slopes
- Addition of plastic liners to the hoppers to reduce friction
- The addition of vibrators along sloping walls of hoppers
- Enlarging hopper outlets and feeders
- Addition of coal additives to reduce surface moisture

Ash-Handling System
The increase in fuel firing rate discussed previously can also affect the capability of the ash-handling system. The bottom-ash-to-fly-ash ratio may change when converting to PRB coal, potentially having a major impact on the fly ash handling system. Modifications that may be required to accommodate the increase fly ash loading are:

- Increasing the size of the exhausters for a vacuum system
- Converting a vacuum system to a pressurized system
- Increasing the size of the blowers for a pressurized system

Makeup Water Equipment
For PRB coal, the increase water usage for steam sootblowing and dust suppression may require additional makeup pretreatment as well as additional demineralizer and condensate storage capacity.

Wastewater System

Fuel Switching for CSAPR Compliance

The quantity and chemistry of discharge effluent from the coal pile runoff, low-volume wasters, ash transport water, metal cleaning wastes, or makeup demineralizer regeneration wastes may be changed by the different characteristics of PRB coal and ash. The adequacy of existing equipment must be verified for conversion to PRB coal. Additional wastewater segregation and storage capabilities and/or chemical treatment facilities may be required.

Auxiliary Power Equipment
With the addition and modification of equipment required to convert to PRB coal, the capacity of the existing auxiliary power equipment may be exceeded. Additional components such as new auxiliary power transformers may be needed to provide the increased load and desired operational flexibility.

Net Present Value Analysis
Based on the large variation in equipment upgrades and modifications that may be required, capital costs for switching to PRB can vary significantly. Reviewing costs from past PRB conversions, it is estimated that a PRB conversion at HMP&L, Wilson, and Green would cost between approximately $70/kW and $100/kW, depending on the extent of work that is needed. A detailed analysis would need to be conducted to assess the exact scope that would be required to switch to PRB fuel at each of the units. However, for the purposes of this NPV analysis, $70/kW was used to ensure that the NPV values were not artificially over-estimated.

To estimate the O&M impact of fuel switching, S&L was given $2.00/MMBtu as the cost of BREC's bituminous fuels. PRB fuels are likely to cost closer to $3.00/MMBtu because of the higher transportation costs associated with shipping coal from Wyoming. It's important to note that S&L is under-estimating O&M costs because no costs have been included to account for more stringent housekeeping or more rigorous equipment maintenance that would be required.

Using the capital and O&M costs, S&L compared the NPV associated with the compliance plan recommended in the original report to switching fuels to PRB. The results are presented in the table below. It can be seen in the table that the higher fuel costs result in a significantly higher annual O&M costs, which has a significant impact on the NPV for fuel switching.

For HMP&L, Wilson, and Green Unit 2, fuel switching results in a NPV that is approximately $700 million higher than the total NPV for the compliance plan outlined in the original report. Therefore, fuel switching as a means for complying with CSAPR is not recommended by Sargent & Lundy for the Big Rivers Units.

Fuel Switching for CSAPR Compliance

Parameter		Wilson FGD	HMP&L FGD Mods	Green 2 SCR	Wilson Fuel Switch	HMP&L Fuel Switch	Green 2 Fuel Switch
Evaluation Period	Years	20	20	20	20	20	20
Discount rate	%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%
Capital Cost Escalation Rate	%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
O&M Escalation Rate	%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
Base Year		2011	2011	2011	2011	2011	2011
Present value Year		2011	2011	2011	2011	2011	2011
Installation year		2014	2014	2014	2014	2014	2014
Levelized Fixed Charge Rate		10.13%	10.13%	10.13%	10.13%	10.13%	10.13%
Capital Cost	**$**	**139,000,000**	**6,300,000**	**81,000,000**	**30,800,000**	**23,590,000**	**17,080,000**
Total O&M	**$/yr**	**690,000**	**760,000**	**2,160,000**	**37,150,000**	**26,120,000**	**20,410,000**
Net Present Value	**$**	**126,215,000**	**13,307,000**	**91,850,000**	**413,109,000**	**292,112,000**	**227,096,000**
Differential NPV		---	---	---	286,894,000	278,805,000	135,246,000
Total Differential NPV		---	---	---	---	---	700,945,000

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

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

DIRECT TESTIMONY

OF

THOMAS L. SHAW
DIRECTOR, ENVIRONMENTAL SERVICES

ON BEHALF OF

BIG RIVERS ELECTRIC CORPORATION

FILED: April 2, 2012

DIRECT TESTIMONY
OF
THOMAS L. SHAW

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DIRECT TESTIMONY
OF
THOMAS L. SHAW

I. INTRODUCTION

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

A. My name is Thomas L. Shaw. I am the Director, Environmental Services, for Big Rivers Electric Corporation ("Big Rivers"). My business address is 201 Third Street, Henderson, Kentucky 42420. A complete statement of my education and work experience is attached to this testimony as Exhibit Shaw-1.

Q. Have you previously testified before the Kentucky Public Service Commission ("Commission")?

A. No. I have assisted in responding to data requests in a previous proceeding before the Commission.

Q. Are you sponsoring any exhibits?

A. The only exhibit to my testimony is Exhibit Shaw-1, which describes my education and work experience. Also, when Big Rivers files its applications with the Kentucky Energy and Environment Cabinet, Division for Air Quality ("KYDAQ") for the necessary changes to its Title V operating permits, Big Rivers will file copies of the applications in the record of this proceeding.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to identify the environmental regulatory requirements that cause the need for the pollution control facilities in Big Rivers' 2012 environmental compliance plan ("2012 Plan") and demonstrate how those facilities will allow Big Rivers to comply with these environmental regulations. A copy of the 2012 Plan is presented as Exhibit Berry-2 in the Direct Testimony of Robert W. Berry. The projects identified in the 2012 Plan are necessary for Big Rivers' compliance with the requirements of the Clean Air Act as amended ("CAAA"), the proposed Cross-State Air Pollution Rule ("CSAPR"), and the proposed national emission standards for hazardous air pollutants, also known as the Mercury and Air Toxics Standard ("MATS") rule.

III. ENVIRONMENTAL REGULATIONS AND PERMITS

Q. Please describe current environmental regulation.

A. Environmental compliance is an ongoing, everyday activity at our facilities and for our operations. The passage of the initial Clean Air Act in 1970, the Clean Water Act, and the Resource Conservation and Recovery Act ("RCRA"), and subsequent amendments to and revisions of these and other environmental laws and regulations have significantly increased Big Rivers' environmental compliance obligations over time. There is a need for continuous investment in, and maintenance of, environmental pollution control equipment and facilities. The improvement of air quality has given rise to the stringent environmental regulations issued by the U.S. Environmental Protection Agency ("EPA") that, in turn, have caused the need for the pollution control projects in Big Rivers' 2012 Plan.

Q. What environmental laws and regulations are applicable to the control of air emissions from coal-fired generating stations?

A. Under the CAAA, Big Rivers is regulated by federal and state agencies. The EPA has granted Kentucky the functional responsibility for implementing the provisions of the CAAA through the State Implementation Plan ("SIP") process. All of the Big Rivers and Henderson Municipal Power & Light ("HMP&L") Station Two coal-fired units in Kentucky fall under the jurisdiction of KYDAQ and must comply with regulations promulgated by the state agency, most notably in the form of the Title V permits that KYDAQ issues to utility generating stations. Likewise, the functional responsibility for implementing and enforcing the Clean Water Act and RCRA has been granted to Kentucky. The Kentucky Division of Water ("KYDOW") and the Kentucky Division of Waste Management ("KYDWM") manage the water and waste management issues for the Cabinet, respectively. In addition to obtaining Title V permits from KYDAQ, utilities must also obtain permits from KYDOW and KYDWM to operate coal-fired electric generating stations.

At issue in this application is the effect of EPA's CSAPR and MATS rule on the Big Rivers and the HMP&L Station Two generating stations.

Q. Does Big Rivers' 2012 Plan list the environmental permits and regulations that are applicable to Big Rivers?

A. Yes. My testimony describes the environmental regulations and permit requirements applicable to Big Rivers, and Big Rivers' 2012 Plan (Exhibit Berry-2) summarizes these regulations and requirements. The pollution control facilities listed as Projects 4 through 11 in the 2012 Plan will enable Big Rivers to continue to fulfill its environmental compliance obligations. The environmental permits applicable to the proposed projects are set out in the column entitled Permits in the 2012 Plan.

Q. What are the environmental regulations driving Big Rivers' 2012 Plan?

A. CSAPR and the MATS rule are driving the vast majority of what Big Rivers proposes in its 2012 Plan. It is important to note that both are successors to earlier rules: the proposed CSAPR is the successor to the Clean Air Interstate Rule ("CAIR"), though it imposes tighter restrictions on sulfur dioxide ("SO_2") and nitrous oxides ("NO_x") to reduce 2.5-micron particulate matter ("$PM_{2.5}$") emissions. Likewise, the MATS rule is the successor to the Clean Air Mercury Rule ("CAMR"), and it imposes significant new and tightened emissions restrictions for mercury, particulate matter (a surrogate for hazardous non-mercury metals), and hydrogen chloride ("HCl") a surrogate for hazardous acid gases).

IV. CLEAN AIR INTERSTATE RULE AND CROSS-STATE AIR POLLUTION RULE

Q. Please describe CAIR and CSAPR and their relationship to each other.

A. EPA regulates interstate air pollution using Section 110 of the CAAA. This section allows EPA to issue rules to prevent a state (or states) from "contribut[ing] significantly to nonattainment in, or interfer[ing] with maintenance by, any other State with respect to any ... national primary or secondary ambient air quality standard[.]"[1] On March 15, 2005, EPA exercised that authority by issuing the Clean Air Interstate Rule, which required significant reductions in SO_2 and NO_X emissions in an attempt to bring a number of states and regions into compliance with the National Ambient Air Quality Standards ("NAAQS") for $PM_{2.5}$ and eight-hour ozone (smog). SO_2 is a precursor of $PM_{2.5}$ and NO_X is a precursor of $PM_{2.5}$ and ozone. The rule applies to the eastern 28 states (including Kentucky) and the District of Columbia. It reduces emissions through cap-and-trade, allowance-based programs, and allows for open, interstate trading of SO_2 and NO_X allowances.

However, a number of states and other interveners challenged CAIR in court on several grounds, and on July 11, 2008, the U.S. Court of Appeals

[1] See 42 U.S.C. 7410(a)(2)(D)(i)(I) ("[Each SIP shall] contain adequate provisions... prohibiting, consistent with the provisions of this subchapter, any source or other type of emissions activity within the State from emitting any air pollutant in amounts which will... contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any such national primary or secondary ambient air quality standard [.]").

for the D.C. Circuit vacated CAIR and remanded it to EPA for re-promulgation in a form consistent with the court's opinion.[2] The court placed CAIR back into effect several months later, and CAIR remains in effect today pending final promulgation of a regulation by EPA to replace CAIR.[3]

On July 6, 2011, pursuant to the court's orders, EPA finalized its replacement for, and enhancement to, CAIR in the form of the Cross-State Air Pollution Rule, CSAPR.[4] The new rule is designed to achieve emissions reductions from power plants beginning in January 2012, with additional reductions to be in place for 2014 and following years. CSAPR creates more stringent state-specific allowance budgets (or "caps") for SO_2 and NO_X, and allows sources to trade emission allowances with other sources within the same program (*e.g.* ozone season NO_X) in the same or different states, while firmly constraining any emissions shifting that may occur by requiring a strict emission ceiling in each state. These strict emissions ceilings in each state are expected to drive up the cost of allowances and necessitate reducing Big Rivers' SO_2 and NO_X emissions over time.

On October 6, 2011, EPA proposed technical revisions to CSAPR, and in a separate, but related action, EPA finalized a supplemental rule to require six additional states to make summertime NOx reductions under the CSAPR ozone season control program. On December 23, 2011, EPA

[2] *North Carolina v. EPA*, 531 F. 3d 896 (D.C. Cir. 2008).

[3] *North Carolina v. EPA*, 550 F.3d 1176, 1178 (D.C. Cir.2008) ("We therefore remand these cases to EPA without vacatur of CAIR so that EPA may remedy CAIR's flaws in accordance with our July 11, 2008 opinion in this case.").

[4] The CSAPR Final Rule was published in the Federal Register on August 8, 2011. (76 Fed. Reg. 48208).

proposed to approve the CSAPR trading program as an alternative to Best Available Retrofit Technology ("BART").

On December 30, 2011, the United States Court of Appeals for the D.C. Circuit stayed implementation of CSAPR pending judicial review of the merits of the rule. However, it is widely believed that the rule will ultimately be imposed in a form substantially similar to its current form.

Q. What steps does Big Rivers propose to take to comply with CSAPR?

A. As discussed in greater detail in Mr. Berry's testimony, Project Numbers 4 through 7 of Big Rivers' 2012 Plan contain elements to reduce SO_2 and NO_x emissions. Specifically, Big Rivers proposes to control SO_2 emissions through the installation of a new tower scrubber at Wilson Station and the modification of the existing scrubber at HMP&L Station Two Units 1 and 2 to increase SO_2 removal efficiency. Big Rivers intends to further control NO_x emissions at Green Station by installing a Selective Catalytic Reduction system ("SCR") on Green Unit 2. The conversion of Reid Unit 1 to natural gas will also result in reduced emissions of SO_2 and NO_x relative to burning coal. As more fully described in Mr. Berry's testimony and in the direct testimony of William DePriest, these scrubber and SCR-related project elements, in addition to the Reid Unit 1 conversion, are the most cost-effective way for Big Rivers to comply with CSAPR.

Q. Why is Big Rivers proposing to take steps to comply with an environmental regulation that has been stayed?

A. Although CSAPR has been stayed, the stay is not based on the merits of the rule, and EPA is committed to ensuring that interstate emissions are reduced to at least the levels set out in CSAPR. In implementing the rule, EPA was mindful of the court's instruction to "decide what date, whether 2015 or earlier, is as expeditious as practicable for states to eliminate their significant contributions to downwind nonattainment."[5]

The reductions required by CSAPR are necessary for nonattainment areas to meet the December 2014 compliance deadline for the ground level ozone and $PM_{2.5}$ NAAQS.

In short, there is every reason to believe that CSAPR will become final and binding in its current form very soon, and EPA is committed to seeing that NO_x and SO_2 restrictions at least as stringent as those in CSAPR will go into effect. Big Rivers simply cannot wait to initiate its 2012 Plan regarding SCRs until the rule is final. As explained further by Mr. Berry, with Big Rivers beginning now, the 2014 compliance date leaves little time for installing SCRs.

V. CLEAN AIR MERCURY RULE & MERCURY AND AIR TOXICS STANDARD

Q. Please describe CAMR and the MATS rule and their relationship to each other.

A. To understand CAMR and the MATS rule, it is important to understand the

[5] 76 Fed. Reg. 48277.

history of the statutory authority upon which EPA relied to issue both rules, as well as the regulatory actions EPA has taken under that statutory authority to date.

Section 112 of the 1970 Clean Air Act required EPA to identify and list Hazardous Air Pollutants ("HAPs") and determine which HAPs emission sources should be regulated. In 1990, Congress amended Section 112 by eliminating much of EPA's discretion in such matters and added more than one hundred specific HAPs, including mercury compounds. The revised Section 112 did not require EPA to regulate electric generating units with respect to HAPs emissions per se, but it did require EPA to conduct a study to determine if it would be appropriate to regulate electric generating units with respect to HAPs emissions. Section 112 further provided that "The Administrator **shall** regulate [electric generating units] under this section, if the Administrator finds such regulation is appropriate and necessary after considering the results of the study required by this subparagraph."[6]

The EPA completed the required study in 1998 and found "a plausible link between anthropogenic releases of mercury from industrial and combustion sources in the United States and methyl mercury in fish" and that "mercury emissions from [electric generating units] may add to the

[6] CAAA § 112(n)(1)(A) (emphasis added).

existing environmental burden."[7] In light of the study, the EPA announced on December 20, 2000, that it was "appropriate and necessary" to regulate coal- and oil-fired electric generating units concerning HAPs emissions, and particularly mercury, under Section 112.[8]

On January 30, 2004, EPA proposed two alternatives to regulate electric generating unit emissions.[9] The first alternative was to regulate electric generating units under Section 112 by issuing Maximum Achievable Control Technology ("MACT") standards (or achieving an equivalent result with a cap-and-trade system). (For existing emission sources, a MACT-based emission standard must be at least as stringent as "the average emission limitation achieved by the best performing 12 percent of the existing sources ...").[10] The second alternative proposed to remove electric generating units from the list of HAPs sources regulated under Section 112, and instead to regulate electric generating unit mercury emissions under Section 111, which permits EPA much more discretion concerning the stringency of the requirements it must impose (in particular, it allows EPA to require emissions restrictions less severe than the minimum mandatory MACT requirement of Section 112).

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[7] EPA, OFFICE OF AIR QUALITY PLANNING AND STANDARDS, STUDY OF HAZARDOUS AIR POLLUTANT EMISSIONS FROM ELEC. UTIL. STEAM GENERATING UNITS – FINAL REPORT TO CONG. 7-1,45 (1998).

[8] *Regulatory Finding on the Emissions of Hazardous Air Pollutants from Electric Utility Steam Generating Units*, 65 Fed. Reg. 79,825, 79,827 (Dec. 20, 2000).

[9] *Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units*, 69 Fed. Reg. 4652 (Jan. 30, 2004).

[10] CAAA § 112 (d)(3)(A) (emphasis added).

On March 29, 2005, EPA chose the second alternative and de-listed electric generating units as a regulated source group under Section 112, then promulgated the final CAMR under Section 111 on May 18, 2005. CAMR created a cap-and-trade, allowance-based system to reduce electric generating unit mercury emissions that was to be implemented in two phases. In Phase I (2010-2017), mercury emissions were to be capped at 38 tons nationwide. In Phase II (2018 and beyond), mercury emissions were to be reduced to 15 tons nationwide. In addition to the basic cap-and-trade system that covered all electric generating units, CAMR implemented a mercury emission limit for new electric generating units (or those subject to new-source standards due to having made major modifications). For bituminous-coal-fired units like Big Rivers' units and HMPL Station Two, CAMR's mercury emission limit for new units was 21 lbs/terawatt-hour ("TWh").[11]

In early 2008, the U.S. Court of Appeals for the D.C. Circuit vacated CAMR, not because it was too restrictive or because regulating electric generating units' mercury emissions was outside EPA's CAAA authority, but rather because, in effect, EPA had been insufficiently restrictive.[12]

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[11] *Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units,* 70 Fed. Reg. 28,606, 26,653 (2005) (CAMR § 60.45a(a)(1): "For each coal-fired electric utility steam generating unit that burns only bituminous coal, you must not discharge into the atmosphere any gases from a new affected source which contain Hg in excess of 21 x 10^{-6} pound per megawatt hour (lb/MWh) or 0.021 lb/gigawatt-hour (GWh) on an output basis.").

[12] *In the Matter of: The Application of Kentucky Utilities Company for a Certificate of Public Convenience and Necessity to Construct a Selective Catalytic Reduction System*

More precisely, the court held that EPA had not made the appropriate findings to de-list electric generating units from Section 112 (the CAAA section that requires MACT standards), so EPA could not regulate existing electric generating units under a Section 111-based scheme. Finding that the regulation of existing electric generating units was integral to EPA's overall regulation of mercury emissions, the court vacated the entire regulation and remanded the matter to EPA either to de-list electric generating units from Section 112 after making the appropriate factual findings or to issue appropriate HAPs regulations for electric generating units under Section 112.

EPA chose the latter course, and on February 16, 2012, published its final MATS rule. This means that the required equipment must be installed and operational prior to February 16, 2015, unless Big Rivers requests and is given a one-year extension for compliance to February 16, 2016. For existing coal-fired units designed for coal with at least 8,300 British thermal units ("Btu")/lb (including all Big Rivers' units) the limit for mercury is 1.2 lbs/Trillion Btu ("TBtu") (13lbs/TWh). This limit is over 35% more restrictive than CAMR's requirement.

Q. What other emissions does the MATS rule address?

A. The MATS rule also regulates emissions of particulate matter (as a

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and Approval of Its 2006 Compliance Plan for Recovery by Environmental Surcharge, Case No. 2006-00206, Order at 19 (Dec. 21, 2006); *In the Matter of: The Application of Louisville Gas and Electric Company for Approval of Its 2006 Compliance Plan for Recovery by Environmental Surcharge*, Case No. 2006-00208, Order at 19 (Dec. 21, 2006).

surrogate for hazardous non-mercury metals), HCl, and hydrogen fluoride ("HF"). HCl and HF are referred to as "acid gases." The MATS rule's emission limit for total particulate matter from existing electric generating units is 0.030 lb/Million Btu ("MMBtu"). For HCl, the MATS rule's emission limit from existing electric generating units is 0.0020 lb per MMBtu; however, the MATS rule allows SO_2 to be measured as a surrogate for directly measuring HCl, and this is the measure Big Rivers will use. The SO_2 limit as a surrogate for HCl under the MATS rule is 0.20 lb per MMBtu. Since Big Rivers already has the necessary equipment for monitoring SO_2 emissions and believes that its emission control strategy will enable it to meet the surrogate limit of 0.20 lb per MMBtu, it will use the surrogate limit.

Q. What steps does Big Rivers propose to take to comply with the MATS rule?

A. Big Rivers intends to implement a combination of strategies to comply with the numeric limitations of the MATS rule. Big Rivers proposes to achieve compliance using the facilities described in Projects 8 through 11 of Big Rivers' 2012 Plan.

Baseline emissions of mercury at all Big Rivers' units, except the HMP&L units, have emissions above the limit of 1.2 lb/TBtu. Big Rivers intends to install Activated Carbon Injection systems at all facilities except the HMP&L units to meet the mercury limit. The MATS rule also requires evidence of continuous compliance with the mercury limit, and Big Rivers plans to install continuous emission monitors at all facilities, including the HMP&L units.

With respect to acid gas removal, Big Rivers plans to add a hydrated lime injection system (known also as Dry Sorbent Injection) at Coleman Units 1, 2, and 3, Wilson Unit 1, and Green Units 1 and 2. It is anticipated that the combination of Dry Sorbent Injection and the necessary reductions to meet the 2014 CSAPR allocations will result in unit SO_2 emission rates below 0.20 lb/MMBtu, which will allow for use of SO_2 emissions data as a surrogate for demonstrating compliance with the acid gas provisions of the MATS rule.

As more fully described in Mr. Berry's and Mr. DePriest's testimony, these project elements are the most cost-effective way for Big Rivers to comply with the MATS rule. Big Rivers has been, and will continue to be, in contact with KYDAQ concerning these compliance issues. Big Rivers intends to contact KYDAQ to provide its staff copies of this application immediately after Big Rivers files it with the Commission. But it is also prudent for Big Rivers to come to the Commission now to seek approval for the facilities it will need to comply with these rules.

VI. COAL COMBUSTION RESIDUALS REGULATION

Q. Please describe the EPA's proposed CCR regulation.

A. On June 21, 2010, EPA published a Notice of Proposed Rulemaking ("NOPR") that proposed different versions of a rule under RCRA to regulate Coal Combustion Residuals ("CCR") (the first time EPA has proposed such a regulation under RCRA). As the NOPR states multiple times, EPA is concerned about the safety and potentially harmful environmental effects of CCR storage facilities, and particularly of surface impoundments (*i.e.*, ash ponds) in the wake of the TVA Kingston impoundment breach in December 2009. Thus, the main thrust of the regulation is to give greater regulatory oversight, whether at the federal or state level, to the storage of CCR.

The CCR NOPR sets forth multiple regulatory options for CCR. EPA's stated preference is to regulate CCR as a hazardous waste under RCRA Subtitle C. This would provide EPA "cradle-to-grave" regulatory oversight of the creation, transportation, storage, and ultimate disposition of CCRs. It would also impose on surface impoundments, including existing impoundments, stringent liner requirements, siting requirements, closure requirements, a weekly inspection regime, and groundwater monitoring requirements (just to name a few of the multitude of new requirements this option would impose). EPA plainly states in the NOPR that, "for all practical purposes, [treating CCR as a hazardous waste] will have the effect of requiring the closure of existing surface impoundments receiving CCRs...."[13] As proposed, this option would have the effect of requiring surface impoundments to close within seven years of the rule's issuance (though some additional time may be available as state agencies work the federal rules into their state implementation plans). The ultimate result would be to have only CCR landfills and to eliminate entirely CCR surface impoundments or ponds.

The other primary option in the CCR NOPR is to classify CCR as a non-hazardous waste under RCRA Subtitle D. This approach would not create a cradle-to-grave regulatory regime, but would rather result in the promulgation of minimum storage standards for states to enforce. Those requirements would be expected to include liner, inspection, and groundwater monitoring requirements similar to Subtitle C, but less strict with respect to operation and location. Even under the main Subtitle D approach, though, the compliance obligations are significantly less stringent for landfills than for surface impoundments.

The sub-option under the Subtitle D approach (called "D Prime") is to have existing storage facilities operate as-is to the end of their useful lives, so that only new landfills and surface impoundments would have to comply with new Subtitle D liner, location, and operational requirements.

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[13] *Hazardous and Solid Waste Management System: Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals from Electric Utilities*, 75 Fed. Reg. 35, 128, 35, 177 (2010).

Q. Has the Kentucky Division of Waste Management expressed a view on the most appropriate method of compliance?

A. Yes. KYDWM management personnel have communicated that landfills are the preferred option for handling, storage and disposal of CCRs, but there is no current regulation that would require such construction. KYDWM has indicated that landfill permitting will be available for companies that choose to implement an alternative to surface impoundments for management of CCRs while EPA finalizes its regulatory approach.

Q. What steps does Big Rivers propose to take to comply with the CCR NOPR?

A. The alternatives under consideration by EPA are of such substantially different form that Big Rivers believes that an immediate response to the proposal would not be appropriate. However, due to the likelihood that a final CCR storage rule will require closure or conversion of surface impoundments, Big Rivers is not planning to construct new surface impoundments at this time. Big Rivers will continue to monitor the rule and possible compliance alternatives, including converting existing ponds to dry bottom ash systems using submerged scraper conveyors ("SSCs").

VII. <u>CLEAN WATER ACT SECTION 316(b) IMPINGEMENT MORTALITY AND ENTRAINMENT</u>

Q. Please describe EPA's rules relating to Impingement Mortality and Entrainment under Section 316(b) of the Clean Water Act

A. On April 20, 2011, to protect fish and other marine life that could be harmed in water intake facilities, EPA published in the Federal Register proposed regulations implementing Section 316(b) of the Clean Water Act[14] at all existing power generating facilities and other industrial and manufacturing facilities that withdraw more than 2 million gallons per day (MGD) of water from waters of the U.S. and use at least 25% of the water they withdraw exclusively for cooling purposes. The proposal would require reductions in fish impingement mortality by selecting one of two options for meeting Best Technology Available ("BTA") requirements. The proposal would also establish entrainment mortality performance standards based on the size of the design intake flow of the facility and a case-by-case evaluation by the permitting authority.

Q. What steps does Big Rivers plan to take to comply with the proposed rule implementing Section 316(b)?

A. The alternatives described in the proposal are of such substantially different form that Big Rivers believes that an immediate response to the proposal would not be appropriate. Big Rivers will continue to monitor the

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[14] *National Pollutant Discharge Elimination System—Cooling Water Intake Structures at Existing Facilities and Phase I Facilities; Proposed Rule,* 76 Fed Reg. 22174 (2011).

rule and will consider modifications to the existing intake structures at certain of its facilities.

VIII. U.S. ENVIRONMENTAL PROTECTION AGENCY ENFORCEMENT ACTIONS

Q. Are there any EPA enforcement actions that are giving rise to parts of Big Rivers' proposed 2012 Plan?

A. No.

IX. RECOMMENDATION AND CONCLUSION

Q. What is your recommendation to the Commission?

A. The EPA's CSAPR and MATS rules have created significant compliance obligations that Big Rivers cannot ignore, and any delay in beginning to take action to put in place the proposed compliance measures will serve only to place Big Rivers' members and their retail customers at risk of bearing much higher compliance costs to achieve the same ends. I therefore recommend that the Commission approve Big Rivers' 2012 Plan as filed.

Q. Does this conclude your testimony?

A. Yes, it does.

BIG RIVERS ELECTRIC CORPORATION

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

CASE NO. 2012-00063

VERIFICATION

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

Thomas L. Shaw

Thomas L. Shaw

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Thomas L. Shaw on this the 26th day of March, 2012.

Paula Mitchell

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

Professional Summary

Thomas L. Shaw

Director, Environmental Services

Big Rivers Electric Corporation

201 3rd Street

Henderson, Kentucky 42420

(270) 844-6031

Education

PhD Candidate Environmental Resources and Policy

University of Southern Illinois Carbondale,
Expected Completion Date 2012

MS Industrial Management

University of Southern Indiana, 2000

BS Environmental Science

University of Evansville, 1980

Professional Experience

Big Rivers Electric Corp. 2009 to present

Director, Environmental Services

Manager of Environmental Services

Western Kentucky Energy 1997 - 2009

Manager of Environmental Services

Team Leader Environmental

Big Rivers Electric Corp. 1980 - 1997

Waste Management & Water Quality Supervisor

Environmental Scientist

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

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

DIRECT TESTIMONY

OF

MARK A. HITE
VICE PRESIDENT, ACCOUNTING &
INTERIM CHIEF FINANCIAL OFFICER

ON BEHALF OF

BIG RIVERS ELECTRIC CORPORATION

FILED: April 2, 2012

DIRECT TESTIMONY
OF
MARK A. HITE

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DIRECT TESTIMONY
OF
MARK A. HITE

I. INTRODUCTION

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

A. My name is Mark A. Hite. My business address is 201 Third Street, Henderson, Kentucky, 42420. I am employed by Big Rivers Electric Corporation ("Big Rivers") as Vice President of Accounting and Interim Chief Financial Officer. I was first employed by Big Rivers in 1983, and have held various accounting and finance positions within Big Rivers during my tenure. Prior to being employed by Big Rivers in 1983, I was employed as a Staff Accountant by Southern Indiana Gas & Electric Company, now Vectren Corporation, for three years. A summary of my professional experience is provided as Exhibit Hite-1.

Q. Have you previously testified before the Kentucky Public Service Commission ("Commission") or other regulatory bodies?

A. Yes. I have testified before this Commission on behalf of Big Rivers in several proceedings over the years.

Q. Briefly describe your education and professional certifications.

A. I obtained the degree of Bachelor of Science in Accounting in 1980, and the degree of Master of Business Administration in 1986, both from the University of Evansville. I became a Certified Public Accountant in 1990.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is (a) to describe Big Rivers' evaluation of the cost effectiveness of the alternatives considered for inclusion in the Big Rivers 2012 environmental compliance plan ("2012 Plan"), including the methodology, major assumptions, sensitivity analyses, and results; (b) to describe the accounting associated with the projects in the 2012 Plan and affirm that the costs for which Big Rivers is seeking recovery through its environmental surcharge ("ES") tariff rider are not included in base rates; (c) to describe how Big Rivers plans to finance the construction of the projects included in the 2012 Plan; and (d) to describe the request for authority to establish a regulatory asset for the costs associated with preparing and filing this case and to recover such costs through the ES tariff.

Q. Do you sponsor any exhibits to your testimony?

A. Yes. I have prepared the following exhibits to my prepared testimony:

Exhibit Hite-1 – Professional Summary;

Exhibit Hite-2 – Compliance Options;

Exhibit Hite-3 – Evaluation Assumptions;

Exhibit Hite-4 – Evaluation Results: NPVRR; and

Exhibit Hite-5 – Regulatory Account Estimate.

III. COST-EFFECTIVENESS EVALUATION

Q. Did Big Rivers perform an analysis of the cost effectiveness of various compliance strategies?

A. Yes. Big Rivers considered the recommendations provided by Sargent & Lundy, LLC ("S&L") described in the Direct Testimony of Robert W. Berry and the Direct Testimony of William DePriest. Big Rivers also considered the availability of generating capacity and energy from the wholesale energy market that could be provided in lieu of generation from Big Rivers' own generating units. Big Rivers used this information and other data to perform an evaluation of the cost effectiveness of several compliance strategies, discussed below.

Q. What broad strategic assumptions did you make in performing this analysis?

A. We made two basic assumptions in our analysis. First, the only options for Big Rivers were to operate its units in compliance with the environmental regulations or to replace the capacity of the affected units with purchased power. Second, the proposed suite of environmental facilities contained in the 2012 Plan was the most cost-effective suite of technology options. In other words, an analysis of numerous combinations of the technologies that were assessed by S&L was not necessary, because S&L conducted its own cost-effectiveness evaluation of technology alternatives.

Q. What alternatives did Big Rivers include in its cost-effectiveness evaluation?

A. Building upon the alternative strategies that Big Rivers considered for environmental compliance, as described in the testimonies of Mr. Berry and Mr. DePriest (including fuel switching, DSM and gas conversion), Big Rivers modeled three cases to evaluate from a cost-effectiveness standpoint. The first case was to comply with the Cross-State Air Pollution Rule ("CSAPR") and the Mercury and Air Toxics Standards ("MATS") by installing all of the equipment noted in Exhibit Hite-2 ($283.49 million in capital), referred to as the "Build Case." The second case was to comply with CSAPR and MATS by installing all of the equipment noted in Exhibit Hite-2 except the Selective Catalytic Reduction ("SCR") on Green Unit 2 ($202.49 million in capital), referred to as the "Partial Build Case." The third case was to comply with MATS by installing the MATS equipment noted in Exhibit Hite-2 ($58.44 million in capital), and to comply with CSAPR by reducing generation and purchasing power in the wholesale market, referred to as the "Buy Case."

Q. How did Big Rivers perform the cost-effectiveness evaluation?

A. Big Rivers developed a financial model to determine the net present value of revenue requirements ("NPVRR") over the 2012 - 2026 (15-year) study period. The financial model is used to evaluate several scenarios and includes the variable costs of power production, wholesale market purchases, and off-system sales that stem from production cost models of each alternative over the study period. The financial model also incorporates the fixed costs of the various projects considered in each scenario. The financial model was used to develop several scenarios.

First, a "status quo" financial model was developed, referred to as the "Base Case," which included no new environmental compliance cost for the 2012 Plan. Similarly, a financial model was developed for each of the three aforementioned environmental compliance options. In summary, four initial financial models were developed, referred to as follows: the Base Case, the Build Case, the Partial Build Case, and the Buy Case. The member and smelter revenue requirement of each of the environmental compliance and sensitivity models was then compared to the Base Case financial model on a net present value basis using Big Rivers' 2010 cost of capital, 7.93%, as the discount rate. The 7.93% discount rate is the same discount rate used in the S&L study. The compliance option that provided the lowest member revenue requirement on a present value basis was considered the most cost-effective.

Q. Did Big Rivers run the production cost models that were used in the evaluation?

A. No. Big Rivers acquired forward pricing data from PACE Global, which included forward hourly energy prices, monthly coal prices, monthly natural gas prices, and monthly allowance prices. This data, along with Big

Rivers' plant specific data was supplied to ACES Power Marketing ("ACES"), who ran all of the production cost models for this evaluation. Data from the ACES production cost models were then entered into Big Rivers' financial model, net of the City of Henderson's share of Henderson Municipal Power & Light ("HMP&L") Station Two.

Q. What were the major assumptions used to develop the alternative scenarios that were considered in the cost effectiveness evaluation?

A. Exhibit Hite-3 outlines the major assumptions that are consistent under all financial model scenarios, as well as the major assumptions that are scenario-specific. Consistency was maintained throughout all financial model scenarios so that the difference in revenue requirement under the various financial models could be attributed solely to the environmental compliance option being analyzed. The determining factors driving the difference in revenue requirement between each of the financial model scenarios were the fixed cost, primarily the cost of capital, and the production cost model output (variable cost) for each of the environmental compliance options. For example, the difference in revenue requirement between the Build Case and the Base Case can be attributed to the fixed cost related to installing the equipment noted in Exhibit Hite-2 ($283.49 million in capital, net of the HMP&L contribution) plus the difference in production cost model outputs between the Build Case and the Base Case.

The production cost models produce different outputs under each of the scenarios analyzed because generation, allowance consumption, variable environmental compliance cost, fuel cost, purchased power cost, and off-system sales revenue all depend on the level of environmental compliance equipment installed and the emission variability limits. Specifically, under the Partial Build Case, and to a greater extent the Buy Case, Big Rivers' generation would be less than the Build Case because emission variability limits would cap emissions and force Big Rivers to reduce generation, thereby reducing off-system sales revenue and increasing the need to purchase power.

Q. Please summarize the results of the cost-effectiveness evaluation.

A. Of the three environmental compliance options analyzed by Big Rivers, the Build Case was the least cost option. As noted in Exhibit Hite-4, the Build Case had the lowest NPVRR, and the highest net present value when compared to the Base Case. The Partial Build Case resulted in a higher revenue requirement than the Build Case on a present value basis, and the Buy Case resulted in an even higher revenue requirement on a present value basis.

Q. Did the cost-effectiveness evaluation include the smelter load at full contract demand levels?

A. Yes. The smelter load was modeled at the combined full annual contract demand level of 850 MW (482 for Century Aluminum of Kentucky General

Partnership ("Century"); 368 for Alcan Primary Products Corporation ("Alcan")).

Q. Did Big Rivers conduct a sensitivity study of the compliance alternatives with the smelter load not included to simulate the relative economics of these options should the smelters terminate their agreements with Big Rivers or otherwise close their operations in the Big Rivers service territory?

A. Yes. Big Rivers analyzed the economic impact of both the Build Case and the Buy Case with a corresponding loss in smelter load starting January 1, 2014. This sensitivity analysis was performed to determine if the least cost option would remain the least cost option if the smelters were to leave Big Rivers' system.

Q. Were the results any different in the smelter load loss sensitivity evaluations?

A. No. The results were the same in the smelter load loss sensitivity runs. As noted in Exhibit Hite-4, the Build/No Smelter Case resulted in a lower member revenue requirement than the Buy/No Smelter Case on a present value basis.

Q. Overall, are the projects included in the 2012 Plan a cost-effective way for Big Rivers to meet the environmental requirements described in this application?

A. Yes. On a present value basis, the projects included in the 2012 Plan, or the Build Case, result in the lowest revenue requirement. This is the case whether or not the smelters are on Big Rivers' system.

IV. ACCOUNTING TREATMENT

Q. Is Big Rivers seeking recovery of Operation and Maintenance ("O&M") expenses associated with the projects in the 2012 Plan?

A. Yes. Big Rivers is seeking recovery of O&M expenses for Project Numbers 4, 5, 7, 8, 9, 10 and 11 of the 2012 Plan. Project Number 6, the conversion of Reid Unit 1 to natural gas, does not have any associated O&M that Big Rivers seeks to recover in the environmental surcharge. All of the other projects in the 2012 Plan include O&M expenses that Big Rivers seeks to recover via the environmental surcharge. The projects are discussed in detail in Mr. Berry's testimony, and the projected expenses are included in Exhibit Berry-2 accompanying Mr. Berry's testimony.

Q. How will Big Rivers identify the O&M expenses associated with the projects in the 2012 Plan?

A. Big Rivers' accounting system permits the tracking of costs in accordance with the Rural Utilities Service ("RUS") System of Accounts, pursuant to RUS Bulletin 1767B-1. Big Rivers intends to adhere to this system of accounts to identify and track the O&M expenses associated with the projects in the 2012 Plan. Big Rivers will use subaccounts to track specific expenses, and will use expenditure type and location codes to track particular costs by plant.

Q. Has Big Rivers adhered to this accounting practice for existing projects subject to cost recovery via the approved environmental surcharge tariff?

A. Yes. For the existing approved projects, Big Rivers adheres to the RUS System of Accounts. Such adherence has proven to be successful. The costs in the RUS accounts will be detailed in the Environmental Surcharge Monthly Report, ES Form 2.50. Exhibit Wolfram-5 provided with the Direct Testimony of John Wolfram presents the proposed Environmental Surcharge Monthly Reports and provides a detailed description of each form.

Q. What depreciation rates will be used in the calculation of the depreciation expense for the capital projects in the 2012 Plan?

A. The depreciation rate to be used for the majority of the new capital projects will be 2.28%, which is the rate for Boiler Plant - Environmental Compliance (Acct 312 A-K) that the Commission approved in its Order dated November 17, 2011, in Big Rivers' most recent rate case, Case No. 2011-00036. For a small portion of the project plant that has a much shorter service life, where appropriate (*e.g.* SCR catalyst layers), Big Rivers will apply a depreciation rate of 20.22%, which is the rate for Short-Life Production Plant - Environmental (Acct 312-LP). These rates were presented in Case No. 2011-00036, Exhibit 54, Direct Testimony of Ted J. Kelly, Exhibit Kelly-1, Page 1 of 2, and were accepted by the Commission on page 20 of its Order dated November 17, 2011.

Q. Please explain how Big Rivers will calculate property taxes associated with the projects in the 2012 Plan.

A. Pollution control facilities in Kentucky are generally categorized as manufacturing machinery. This class of property is exempt from local property taxes and is taxed at the state property tax rate of $0.15 per $100 of net book value.

Q. Are any of the costs for the facilities in the 2012 Plan already included in Big Rivers' base rates?

A. No. The current base rates were approved by the Commission in its Order dated November 17, 2011, in Case No. 2011-00036. No capital expenditures for the new pollution control facilities identified in the 2012 Plan have been incurred to date. None were incurred by Big Rivers during the twelve-month historic test period used by Big Rivers in that case, in any of the accepted pro forma adjustments proposed in that case, or before the issuance of the Commission's November 17, 2011 Order in that case.

Q. Are any of the costs for the facilities in the 2012 Plan already included in Big Rivers' environmental surcharge?

A. No. Big Rivers' ES tariff currently includes only the variable costs associated with Project Numbers 1, 2 and 3 for SO_2, NO_X and SO_3 respectively, pursuant to the Commission's Order dated June 25, 2008 in Case No. 2007-00460.

Q. Will the installation of the projects in the 2012 Plan replace or cause existing facilities to be removed from service?

A. Yes. This is described in Mr. Berry's testimony. As existing equipment is retired from service, both Gross Plant in Service and Accumulated Depreciation will be adjusted to reflect the removal. Any gain or loss will be booked to the Accumulated Depreciation Reserve Account. Depreciation expenses will be reduced, and the monthly ES filings will be adjusted to reflect these reductions. As described in Mr. Wolfram's testimony, Big Rivers will adjust the monthly ES filings, when appropriate, to reflect asset retirements in the Environmental Surcharge Monthly Reports.

V. FINANCING

Q. Please describe Big Rivers' plans for financing the projects in the 2012 Plan.

A. Big Rivers plans to borrow the estimated $283.49 million (net of HMP&L's cost share, and net of capitalized interest) to finance the recommended capital additions to its owned and leased generating facilities. Big Rivers is discussing the potential for a term loan from the RUS, and is also planning presentations in New York and Boston, assisted by Goldman Sachs, with various institutional investors to (i) gauge market receptivity for Big Rivers' bonds, (ii) ascertain capacity and price discovery for Big Rivers bonds, and (iii) gain insight as to whether a private placement or a public offering is best for Big Rivers. This is a common approach for infrequent or first-time issuers in the capital markets. Despite all of the recent generation and transmission ("G&T") capital market financing activity, there have been no G&T BBB- credits accessing the capital markets. Big Rivers will develop a comprehensive presentation for the purpose of introducing and educating investors on Big Rivers, on a confidential basis. Based on the feedback received, Big Rivers and its advisor will develop a best execution strategy. Big Rivers will also discuss the potential for a 2-year, $283.49 million construction revolver with potential lenders, including CoBank and National Rural Utilities Cooperative Finance Corporation ("CFC"), to serve as a bridge to permanent financing, allowing multiple advances thereunder, seeking to minimize interest expense during construction and to minimize the associated adverse statement of operations impact, the net of interest expense, interest capitalized, and rate recovery.

Q. What is Big Rivers' timeline for closing the borrowing agreement(s)?

A. Big Rivers first met with representatives of RUS on March 20, 2012, in Washington D.C. to discuss (among other things) the potential for a term loan. Big Rivers plans to continue discussing the potential for an RUS borrowing for CSAPR and MATS capital expenditures with the RUS. Big Rivers plans to commence the institutional investor presentations in mid-May 2012. By mid-June 2012, with the assistance of Goldman Sachs, Big Rivers hopes to have identified the "short list" of investors, and to commence definitive financing discussions and documentation preparation with them. Big Rivers plans to use Orrick Herrington & Sutcliffe LLP as bond counsel. Big Rivers plans to file the associated financing application with the Commission in early-August 2012. Big Rivers will seek to schedule rating agency (Moody's, S&P and Fitch) visits in September 2012, seeking an indicative investment grade rating of the proposed bond issuance. Finally, Big Rivers plans for a final Commission Order by November 5, 2012, and a closing of bridge or permanent financing as soon thereafter as is reasonable. The shelf life of a pre-closing credit rating (an indicative rating) is about six months, and it is prudent to gain knowledge of the indicative rating well in advance of any bridge financing and commencement of construction activity.

Q. Please describe the permanent debt structure Big Rivers is pursuing.

A. Big Rivers will be seeking an approximate 30-year, fixed rate, level debt service structure. As Big Rivers' member all-requirements contracts are currently scheduled to terminate December 31, 2043, a 30-year final maturity is reasonable.

Q. What interest rate does Big Rivers expect?

A. Current benchmark U.S. Treasury ("UST") rates are near all time lows and all-in financing rates (UST + credit spread) are very attractive. As of March 16, 2012, the yield on the 30-year UST was 3.41%, while the historical 30 year average is a much higher 7.00%. Unfortunately, as is often the case, as UST yields have declined, credit spreads have widened. While understanding that Big Rivers' credit profile is unique, and given the lack of recent BBB- credit G&T market financing, I estimate the current Big Rivers all-in 30 year fixed rate to be 5.78% to 6.16% (3.41% UST + 2.37% to 2.75% Big Rivers' credit spread).

Q. What does Big Rivers estimate the financing cost (primarily legal, underwriting and credit rating service cost) to be?

A. For a $283.49 million deal, a financing cost of 0.75% to 1.00%, or $2.1 million to $2.8 million, is a reasonable expectation. The actual such cost will be deferred and amortized in equal monthly amounts over the life of the bonds.

Q. How does Big Rivers intend to generate the revenues to repay this debt?

A. Big Rivers plans to recoup all allowable costs through its environmental surcharge, as approved by the Commission. The environmental compliance capital expenditure must be financed in a manner that ensures Big Rivers remains in compliance with its credit thresholds per its loan contracts, including achieving a minimum 1.10 Margin for Interest Ratio. Also, the financing plan must ensure that Big Rivers retains investment grade credit ratings from at least two of the aforementioned credit rating agencies.

VI. <u>REGULATORY ASSET</u>

Q. Please explain Big Rivers' request for a regulatory asset for the actual costs associated with developing this Application and prosecuting this case.

A. Big Rivers has incurred costs in developing this Application, and it will incur additional costs to prosecute this case. These costs primarily stem from the retention of experts in the legal, regulatory, and engineering professions. In particular, the costs include Big Rivers' attorney and consultant fees, along with the fees of the engineering consultant that was retained to evaluate the compliance options available to Big Rivers. These costs are significant relative to the level of outside services costs built into Big Rivers' base rates. However, they are necessary and prudent, and Big Rivers should have the opportunity to recover them. As such, Big Rivers requests that the Commission grant Big Rivers the authority to establish a regulatory asset for its actual costs (and accruals for estimated amounts until actual costs can be determined) associated with this case, to amortize those costs over three years, and to recover those costs through the environmental surcharge tariff.

Q. What is the amount of the regulatory asset that Big Rivers seeks to establish and recover via the ES tariff?

A. Big Rivers' estimate of its costs for preparing and prosecuting this case is provided in Exhibit Hite-5. This includes the attorneys' fees, rate consultant fees, and engineering consultant fees. The total amount is then amortized over a three year period, and should be recovered by including 1/36 of the original total amount in the Monthly Pollution Control Operating Expenses term (OE) of the formula for E(m) for each expense month. As defined in Big Rivers' ES tariff, E(m) is the total of each approved environmental compliance plan revenue requirement of environmental costs for the current expense month. The amount should be included in E(m) until such time as the entire regulatory asset amount is recovered via the environmental surcharge, at which point the inclusion of the amount in E(m) should cease.

VII. CONCLUSION & RECOMMENDATION

Q. What are your conclusions and recommendations to the Commission in this proceeding?

A. Based on my testimony and the evaluation/analysis performed under my direction, and because the projects proposed in Big Rivers' 2012 Plan are the most cost-effective means for Big Rivers to comply with the CSAPR and MATS environmental requirements, I recommend that the Commission approve Big Rivers' 2012 Plan, grant the requested certificates of public convenience and necessity, approve the proposed ES tariff and monthly reports as filed, and grant Big Rivers the authority to establish a regulatory asset for its costs associated with this case and authority to recover such costs through the environmental surcharge tariff.

Q. Does this conclude your testimony?

A. Yes.

BIG RIVERS ELECTRIC CORPORATION

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

CASE NO. 2012-00063

VERIFICATION

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

Mark A. Hite
Mark A. Hite

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Mark A. Hite on this the 26th day of March, 2012.

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

Professional Summary

Mark A. Hite

Vice President of Accounting and Interim Chief Financial Officer

Big Rivers Electric Corporation

201 3rd Street

Henderson, Kentucky 42420

(270) 844-6049

Professional Experience

Big Rivers Electric Corporation – 1983 to 2005; 2007 to present

Vice President of Accounting and Interim Chief Financial Officer

Vice President of Accounting

Vice President of Finance and Administrative Services

Manager of Financial Services

Payroll Supervisor

Staff Accountant of Finance

Intermediate Accountant

Accountant

Donaldson Capital Management – 2005-2006

Investment Advisor Representative

Vectren Energy, Evansville, Indiana – 1980–1983

Accountant – General Accounting

Sanders & Company CPAs, Evansville – 1979–1980

Staff Accountant

Sears, Roebuck & Company, Evansville – 1978–1979

Auditing Clerk

Professional Summary

Education

Master in Business Administration

University of Evansville, 1985

Bachelor of Science in Business

University of Evansville, 1980

Professional Certifications

Certified Public Accountant – 1990

Professional Memberships

American Institute of Certified Public Accountants

Indiana CPA Society

Big Rivers Electric Corporation
2012 Environmental Compliance Plan
Compliance Options

Project #	Pollutant	Control Facility	Plant	Environmental Regulation or Regulatory Requirement	Projected Completion	Projected Capital Cost ($ Million)	Projected Capital Cost Net of City ($ Million)
4	SO_2	Flue Gas Desulfurization ("FGD" or "Scrubber")	Wilson Unit 1	Clean Air Act (1990), Cross State Air Pollution Rule ("CSAPR")	2016	139.00	139.00
5	NO_X	Selective Catalytic Reduction ("SCR") @85% Removal	Green Unit 2	Clean Air Act (1990), Cross State Air Pollution Rule ("CSAPR")	2015	81.00	81.00
6	SO_2, NO_X	Convert ~~Existing~~ Burners to Natural Gas	Reid Unit 1	Clean Air Act (1990), Cross State Air Pollution Rule ("CSAPR")	2014	1.20	1.20
7	SO_2	Install Additional Recycle Pump & New Motors On ID Fans	HMP&L Unit1	Clean Air Act (1990), Cross State Air Pollution Rule ("CSAPR")	2015	3.15	1.92
			HMP&L Unit 2		2015	3.15	1.93
8	Mercury	Advanced Carbon Injection, Dry Sorbent Injection and Monitors	Coleman Unit 1	Clean Air Act (1990), Mercury and Air Toxics Standards ("MATS") Rule	2016	9.48	9.48
			Coleman Unit 2		2016	9.48	9.48
			Coleman Unit 3		2016	9.48	9.48
9	Mercury	Advanced Carbon Injection, Dry Sorbent Injection and Monitors	Wilson Unit 1	Clean Air Act (1990), Mercury and Air Toxics Standards ("MATS") Rule	2016	11.24	11.24
10	Mercury	Advanced Carbon Injection, Dry Sorbent Injection and Monitors	Green Unit 1	Clean Air Act (1990), Mercury and Air Toxics Standards ("MATS") Rule	2016	9.24	9.24
			Green Unit 2		2016	9.24	9.24
11	Mercury	Particulate Monitors	HMPL Unit 1	Clean Air Act (1990), Mercury and Air Toxics Standards ("MATS") Rule	2016	0.24	0.14
			HMPL Unit 2		2016	0.24	0.14
					Total ($ Million)	286.14	283.49

Big Rivers Electric Corporation
2012 Environmental Compliance Plan
Financial Model Evaluation Assumptions

Major Assumptions (All Scenarios)

- Targeted a 1.24 TIER

- CoBank/CFC debt issues ($527 million) used to retire $467 million of RUS Series A Note April 2012 and fund capital expenditures
  - Level 20 year debt service
  - Debt issuance cost of $1.77 million amortized over life of new debt
  - Patronage allocation based on CoBank and CFC estimates
  - Approximate all-in rate 4.5%

- RUS Series B Note refinanced in 2023 ($246 million)
  - Borrow additional $70 million to replenish cash and pay down lines of credit
  - Amortize over 20 years – Interest only the first 10 years then level debt service remaining 10 years
  - Interest rate 6%
  - Debt issuance costs (1.3% of amount borrowed) amortized over life of issue

- $58.8 million PC Bond refinanced in 2013
  - Interest Rate 4.5%
  - Interest only payments with 16 year bullet
  - Debt issuance costs (1.3% of amount borrowed) amortized over life of issue

- All Environmental Compliance Plan (ECP) capital financing: Interest only 2013-2015, then level debt service
  - 28 year level debt service
  - Interest Rate 5.5%
  - Debt issuance costs (1.3% of amount borrowed) amortized over life of issue

- Lines of credit used in varying amounts in all scenarios
  - Interest rate – blend of CoBank 2.3% and CFC 3.2%

- Non-Variable O&M costs from 2012-2015 Budget/Financial Plan
  - All ECP costs were removed from the Budget and replaced with more recent estimates
  - $9.0 million in maintenance removed from 2012 and $3.0 million removed from 2013 due to lower off-system sales margin
  - Non-Variable O&M costs escalate at 3% beyond 2015

Big Rivers Electric Corporation
2012 Environmental Compliance Plan
Financial Model Evaluation Assumptions

Major Assumptions (All Scenarios) – *(continued)*

- Production cost models (PCM's) supplied by ACES provide variable cost inputs to financial model
    - ACES production cost model runs are based on PACE Global pricing data

- Member billing units (demand and energy) from Load Forecast Study

- SEPA demand and energy rates are based Budget/Financial Plan years 2012-2015)
    - SEPA returns to normal monthly fixed demand charge in 2015 with rate increase of 5% every 3 years.

- Non-ECP capital based on 2012-2015 Budget/Financial Plan
    - Generation capital decreases from $41.1 million in 2015 to $35.1 million in 2016 then escalates at 3% thereafter. Total non-ECP capital in 2016 is $39.9 million.

- Smelter contracts continue beyond 2023, through 2026, with 2023 terms

- Allowances
    - If short in a given year, purchased needed allowances
    - Slightly long on SO_2 in most cases. Sold excess SO_2 allowances (targeting the same balance in 2026 as 2011 so all cases are comparable)

- The City's share of Station Two is consistent with the 2012-2015 Budget/Financial Plan. The City's share begins 2012 at 110 MW and increases 5 MW every June through 2015, then remains constant thereafter.

Big Rivers Electric Corporation
2012 Environmental Compliance Plan
Financial Model Evaluation Assumptions

Base Case

- CAIR
- No ECP Capital
- Environmental Surcharge (ES) allocated on kWh basis
- PCM (Units dispatched economically, purchased allowances when needed)

Build

- CSAPR and MATS
- Comply by installing equipment
- $283.5 million total ECP capital and borrowing (Net of City)
- ES includes variable costs, fixed costs and return on investment
- Environmental compliance costs allocated on Total Adjusted Revenue method
- Member Rate Stability Mechanism adjusted to accommodate new ES allocation method
- PCM (Units dispatched economically - emissions capped at allocation plus variability limit)

Partial Build

- Similar to Build except no SCR at Green
- $202.5 total ECP capital and borrowing (Net of City)
- PCM (Units dispatched economically - emissions capped at allocation plus variability limit – Purchased power to replace lower generation)

Buy

- CSAPR and MATS
- Comply by installing MATS equipment and reducing generation
- $58.4 million total ECP capital and borrowing (Net of City)
- ES includes variable costs, fixed costs and return on investment
- Environmental compliance costs allocated on kWh basis because costs are predominantly variable
- PCM (Units dispatched economically - Emissions capped at allocation plus variability limit – Purchased power to replace lower generation)

Build (Smelters Leave Sensitivity)

- Same as Build except no smelter load beyond 2013

Buy (Smelter Leave Sensitivity)

- Same as Buy except no smelter load beyond 2013

Big Rivers Electric Corporation
2012 Environmental Compliance Plan
Option Evaluation Results (NPVRR)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Present Value	Net Present Value
Base Case	297.17	282.95	266.73	250.20	232.86	207.37	196.42	178.33	173.77	159.45	153.33	138.75	140.51	128.67	133.93	**2,940.44**	
Environmental Compliance Options																	
Build	301.93	285.91	277.08	265.34	258.98	234.16	220.82	202.97	195.61	181.68	173.31	158.82	158.14	146.15	149.48	**3,210.38**	**(269.94)**
Partial Build	301.90	285.30	281.90	271.50	267.60	247.90	240.10	220.10	214.00	200.70	191.90	177.10	176.80	164.60	168.90	**3,410.30**	**(469.86)**
Buy	317.20	315.40	303.90	293.90	288.80	290.10	281.30	270.90	255.50	250.20	226.10	216.80	204.70	209.30	196.70	**3,920.80**	**(980.36)**
Smelter Load Sensitivities																	
Build (No Smelter Load beyond 2013)	301.90	286.10	31.80	12.60	(10.70)	(58.60)	(79.20)	(79.70)	(87.20)	(99.00)	(102.90)	(121.40)	(117.80)	(114.40)	(95.60)	**(334.10)**	**3,274.54**
Buy (No Smelter Load Beyond 2013)	317.20	311.00	49.70	36.90	14.50	(13.40)	(28.20)	(22.50)	(36.30)	(40.70)	(57.80)	(72.40)	(78.00)	(60.60)	(54.70)	**264.70**	**2,675.74**

Big Rivers Electric Corporation
2012 Environmental Compliance Plan
Estimated Cost for Case Processing
Case No. 2012-00063

Third-Party Costs associated with Case No. 2012-00063

Vendor	Service Provided	Amount
The Prime Group	Rate and Tariff Consultant	$250,000
Sargent & Lundy LLC	Environmental Compliance Consultant	150,000
Sullivan, Mountjoy, Stainback & Miller PSC	Legal	350,000
	Total	$750,000

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

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

DIRECT TESTIMONY

OF

JOHN WOLFRAM
SENIOR CONSULTANT
THE PRIME GROUP, LLC

ON BEHALF OF

BIG RIVERS ELECTRIC CORPORATION

FILED: April 2, 2012

DIRECT TESTIMONY
OF
JOHN WOLFRAM

Table of Contents

DIRECT TESTIMONY
OF
JOHN WOLFRAM

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is John Wolfram and my business address is The Prime Group, LLC, 6001 Claymont Village Drive, Suite 8, Crestwood, Kentucky, 40014.

Q. By whom are you employed?

A. I am a Senior Consultant with The Prime Group, LLC, a firm located in the Louisville, Kentucky area, providing consulting services in the areas of utility rate analysis, cost of service, rate design and other utility regulatory matters.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of Big Rivers Electric Corporation ("Big Rivers").

Q. Please describe your educational background and prior work experience.

A. I received a Bachelor of Science degree in Electrical Engineering from the University of Notre Dame in 1990 and a Master of Science degree in Electrical Engineering from Drexel University in 1997. In March 2010, I joined The Prime Group LLC as a Senior Consultant. In this role, I have developed cost of service studies and rates for numerous electric and gas utilities, including electric distribution cooperatives, generation and transmission cooperatives, municipal utilities and investor-owned utilities. I have also performed economic analyses, rate mechanism reviews, ISO/RTO membership evaluations, and wholesale formula rate reviews. From July 1997 to February 2010, I was employed by the parent companies of Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU"). During that time, I held several roles, advancing through positions in the Energy Marketing, Generation Planning, Rates & Regulatory, and Customer Service areas. Prior to my work with LG&E and KU, I was employed by the PJM Interconnection and by the Cincinnati Gas and Electric Company. A more detailed description of my qualifications is included in Exhibit Wolfram-1.

Q. Have you ever testified before the Kentucky Public Service Commission ("Commission")?

A. Yes. I have testified in numerous regulatory proceedings before this Commission. A listing of my testimony in other proceedings is included in Exhibit Wolfram-1.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the mechanics and components of the proposed Big Rivers environmental surcharge ("ES") tariff rider and explain how the surcharge will be calculated and charged to Big Rivers' members. I will also (1) introduce the proposed, revised ES tariff rider and other tariff sheet revisions; (2) identify the specific cost components of environmental compliance to be included in the surcharge; (3) define Big Rivers' reporting procedures and monthly reports for the environmental surcharge; and (4) provide an estimate of the impact of the costs incurred in connection with the new pollution control projects in Big Rivers' 2012 environmental compliance plan ("2012 Plan") presented in Exhibit Berry-2 to the Direct Testimony of Robert W. Berry.

Q. Do you sponsor any exhibits to your testimony?

A. Yes. I have prepared the following exhibits to my prepared testimony:

Exhibit Wolfram-1 – Qualifications of John Wolfram;

Exhibit Wolfram-2 – Proposed Big Rivers ES Tariff and Other Tariff Sheets;

Exhibit Wolfram-3 – Proposed Big Rivers ES Tariff and Other Tariff Sheets – Redline;

Exhibit Wolfram-4 – Current Big Rivers ES Monthly Reports;

Exhibit Wolfram-5 – Proposed Big Rivers ES Monthly Reports; and

Exhibit Wolfram-6 – Impact on Member Bills.

III. ENVIRONMENTAL SURCHARGE TARIFF

Q. Please describe the existing ES tariff.

A. The existing ES tariff includes the costs associated with three projects approved by the Commission in its Order dated June 25, 2008, in *In the Matter of: The Application of Big Rivers Electric Corporation for Approval of Environmental Compliance Plan and Environmental Surcharge Tariff,* Case No. 2007-00460. In that case, the compliance plan proposed by Big Rivers consisted of programs and the associated operation and maintenance ("O&M") costs dealing with the control of sulfur dioxide ("SO_2"), nitrogen oxides ("NO_X"), and sulfur trioxide ("SO_3"). The costs proposed to be recovered for each of the programs consisted entirely of variable costs that were associated with reagents, disposal of coal-combustion by-products, and allowance purchases as needed (and offset by revenues associated with the sale of allowances and gypsum).

Q. Does the existing Big Rivers ES tariff recover *only* variable costs?

A. Yes. In Case No. 2007-00460, Big Rivers only sought to recover the variable operating expenses, described above, that were associated with the compliance programs. Big Rivers' compliance plan did not include any capital projects or investments in utility plant to comply with the requirements of federal, state, or local environmental statutes or regulations; consequently, Big Rivers did not seek a return on such projects or utility plant.

Q. What is the formula utilized in the existing ES tariff?

A. The Current Environmental Surcharge Factor ("CESF") is defined as

$$CESF = E(m) / S(m)$$

where E(m) is the current month actual cost of compliance according to the tenets of the environmental surcharge statute, and S(m) is the monthly jurisdictional kilowatt-hour ("kWh") sales. Thus, the existing CESF is a per-kWh charge.

Q. Is Big Rivers proposing any changes to its ES tariff?

A. Yes. Big Rivers is proposing changes to its ES tariff. The proposed ES tariff is attached as Exhibit Wolfram-2, and a redline version that identifies the changes to the existing ES tariff is attached as Exhibit Wolfram-3.

Q. Is Big Rivers proposing any changes to the methodology currently used for calculating the monthly environmental surcharge?

A. Yes. Big Rivers is proposing two noteworthy changes to the calculation methodology. The first is a change to the determination of total eligible environmental compliance plan costs, E(m): Big Rivers proposes to add a component to E(m) to recover the fixed costs of the projects in the 2012 Plan (including a return on investment). The second is a change to the cost allocation method used in the formula: Big Rivers proposes to revise the existing "per-kWh" allocation of costs to a "percentage of Total Adjusted

Revenue" allocation of costs. Both changes are proposed in order to accommodate the addition of capital projects to the Big Rivers environmental compliance plan. I describe these two changes further in the next two sections of my testimony.

Q. What is the formula utilized in the proposed ES tariff?

A. The CESF proposed is

$$CESF = E(m) / R(m)$$

where E(m) is the current month actual cost of compliance according to the tenets of the environmental surcharge statute, as revised herein, and R(m) is the rolling twelve-month average of total adjusted revenue for Big Rivers. Thus, the proposed CESF is a percentage-of-revenue charge, not a per-kWh charge.

Q. Does the proposed Big Rivers ES tariff comply with all statutory and regulatory requirements, and all previous Commission Orders on that subject?

A. Yes. And the proposed Big Rivers ES tariff is also consistent with the Commission-approved tariffs of other electric utilities with capital projects in their environmental compliance plans. I discuss this further in the next two sections of my testimony.

IV. COMPLIANCE PLAN COSTS

Q. Does the 2012 Plan include any capital projects or investment in utility plant?

A. Yes. The proposed capital projects total $283.49 million and are discussed in detail in Mr. Berry's and Mr. Hite's testimonies.

Q. What are the cost components included in the proposed ES tariff rider?

A. The proposed ES tariff rider will include the following costs related to the pollution control capital expenditures in the 2012 Plan:

1. a return on pollution control rate base for approved 2012 Plan facilities and equipment;
2. incremental O&M expenses;
3. depreciation over the expected useful life of the relevant pollution control facilities and equipment;
4. property taxes on pollution control equipment;
5. insurance related to pollution control equipment;
6. emission allowance expense;
7. consulting fees; and
8. regulatory asset amounts discussed in Mr. Hite's testimony.

Additionally, the ES tariff rider will continue to include the variable costs associated with Big Rivers' Project Numbers 1, 2 and 3 (for SO_2, NO_X, and

SO_3, respectively) that were approved by the Commission in Case No. 2007-00460, as described above.

Q. Please describe the specific changes to the proposed formula for E(m).

A. Big Rivers proposes that the formula for E(m) be revised to include a component to recover a return on capital investments associated with the projects included in the 2012 Plan.

The *existing* formula for E(m) is:

$$E(m) = OE - BAS$$

where OE is the Operating Expenses for the approved projects and BAS is the net proceeds from By-product and Allowance Sales. Any over-/under-recovery amount from the prior period are also included and are incorporated into OE.

The *proposed* formula for E(m) is:

$$E(m) = [(RB/12)\ (RORB)] + OE - BAS$$

where RB is the environmental compliance rate base, defined as electric plant in service for applicable environmental projects adjusted for accumulated depreciation, cash working capital, spare parts and inventory, and emission allowance inventory, and RORB is the Rate of Return on the environmental compliance plan rate base, designated as the average cost of debt for environmental compliance plan projects approved by the

Commission plus application of a Times Interest Earned Ratio ("TIER"). The OE and BAS terms are unchanged from the existing formula.

Q. What level of TIER does Big Rivers propose to apply?

A. Big Rivers has special contracts in place for two aluminum smelters, Alcan Primary Products Corporation ("Alcan") and Century Aluminum of Kentucky General Partnership ("Century") (collectively, "the Smelters"). These special contracts ("Smelter Agreements") define a TIER Adjustment in Section 4.7.5. The terms of that section effectively limit Big Rivers to a 1.24 TIER as defined in the Smelter Agreements ("Contract TIER"), subject to defined Adjustments. Thus, Big Rivers proposes to apply the Contract TIER of 1.24 in the determination of the RORB term in the formula for E(m) described above.

Q. Please describe the capital cost components included in the environmental surcharge rate base.

A. Big Rivers will include the capital expenditures net of accumulated depreciation for projects included in the 2012 Plan. A working capital component, the emission allowance inventory, spare parts and inventory also comprise the rate base.

Q. How will the cash working capital component of the rate base be determined?

A. Big Rivers will use the working capital formula previously accepted by the Commission to calculate the additional working capital required due to pollution control facility-related O&M expenses. The working capital addition to rate base will be one-eighth of the annual incremental non-fuel O&M expenses of the facilities in the 2012 Plan.

Q. How will E(m) be determined?

A. E(m) will include a return on rate base plus all applicable expenses. This total will be adjusted for recognition of any off-system sales made by Big Rivers (*i.e.* the total cost will be "jurisdictionalized"). In each month, E(m) will be adjusted by the proportion of revenues from sales to native load to the total Big Rivers revenues including off-system sales for the current month ("Jurisdictional Allocation Ratio"). This marks a change in the way that E(m) is currently jurisdictionalized, which is on a kWh basis. The move to a revenue basis is appropriate because of the proposed change to the cost allocation method discussed in Section V of my testimony. This approach is consistent with Commission directives in other environmental surcharge cases.

Q. How will the Return on Rate Base ("RORB") be determined?

A. Big Rivers will calculate the RORB as the average cost of debt for environmental compliance plan projects approved by the Commission plus application of the 1.24 Contract TIER. This return is reasonable and is consistent with the methodology employed by East Kentucky Power Cooperative ("EKPC") approved by the Commission in Case No. 2004-00321.

Q. Is the inclusion of a return component in the formula for E(m) consistent with what the Commission has approved for other utilities whose environmental compliance programs include capital investments?

A. Yes. The Commission has approved the inclusion of a component in the E(m) cost formula for recovering a return on capital investment for several other utilities in Kentucky. These include EKPC (in Case No. 2004-00321), LG&E (in Case Nos. 2011-00162, 2009-00198, and 2006-00208), KU (in Case Nos. 2011-00161, 2009-00197, and 2006-00206), and American Electric Power d/b/a Kentucky Power (in Case Nos. 2009-00459 and 2005-00068).

V. <u>COST ALLOCATION</u>

Q. Does Big Rivers propose to change the way in which the costs E(m) are allocated to Big Rivers' rate classes?

A. Yes. As noted earlier in my testimony, Big Rivers proposes to revise the existing "per-kWh" allocation of costs to a "percentage of Total Adjusted Revenue" allocation of costs. In other words, Big Rivers proposes that the denominator in the current formula for CESF be changed from S(m), which is total kWh, to R(m), which is the twelve-month rolling average of Total Adjusted Revenues.

Q. Why is Big Rivers proposing this change?

A. The existing Big Rivers environmental compliance plan consists entirely of variable costs, which are appropriately allocated by kWh in the approved ES tariff rider. The 2012 Plan introduces capital projects, which include both fixed and variable costs for Big Rivers. It is appropriate for Big Rivers to recover its fixed costs on a demand basis and its variable costs on an energy basis. Because total revenues include both demand-related and energy-related components, it is appropriate to use total revenues as a basis for allocating environmental compliance plan costs. Furthermore, the Commission has approved the allocation of costs on the basis of total revenues for other utilities that include capital projects in their compliance plans; so, the proposed change is consistent with Commission practice and precedent.

Q. How will R(m) be determined?

A. Big Rivers will use the revenues from jurisdictional sales on a rolling twelve-month average basis to determine R(m). Use of a rolling twelve-month average helps to mitigate the effect of swings in monthly revenue that may occur, and is consistent with Commission directives in other environmental surcharge cases. The total revenues for each month for the non-Smelter rate classes will include base rate revenues, fuel adjustment clause ("FAC") revenues, and Non-FAC PPA revenues. The revenues from the Smelters will include revenues from Base Monthly Energy less the

$0.25/MWh contractual premium applied to Base Fixed Energy and will exclude certain revenues that stem from specific sections of the Smelter Agreements. These include the following revenue items (with references to the relevant section of the Smelter Agreements included in parentheses):

1. Supplemental Power (Section 4.3);
2. Backup Energy Charge (Section 4.4);
3. Transmission Charge (Section 4.5);
4. Excess Reactive Demand Charge (Section 4.6);
5. TIER Adjustment Charge (Section 4.7.1);
6. Amortization of Restructuring Amount (Section 16.5.1);
7. Rebate (Section 4.9);
8. Equity Development Credit (Section 4.10);
9. Surcharge (Section 4.11);
10. Surplus Sales (Section 4.13.1);
11. Undeliverable Energy Sales (Section 4.13.1);
12. Potline Reduction Sales (Section 4.13.1);
13. Curtailment of Purchased Power (Section 4.13.2);
14. Economic Sales (Section 4.13.3);
15. Other Credits (Section 4.14);
16. Taxes (Section 4.15); and
17. Other Amounts (Section 5.1).

These revenue items are not included in the total that is used for cost allocation because they are contractual constructs pursuant to the Smelter Agreements that do not universally reflect the relative share of demand-related and energy-related costs associated with serving each of Big Rivers' rate classes. Exclusion of these elements is consistent with the cost allocation methodology employed in the current ES tariff rider, in which the Smelter's Base Monthly Energy (without any adjustments for potline reductions, undeliverable energy, or other kWh variances associated with the Smelter Agreement sections referenced above) is used.

Q. To which items on member bills will the ES billing factor be applied?

A. The CESF will be applied to the same items that are used to derive the CESF; in other words, it will be applied as a percentage to the base rate, FAC, and Non-FAC PPA charges for members served under the standard rate schedules, including RDS, LIC, QFS, and LICX (subject to the terms and conditions of any special contracts established pursuant to the LICX rate schedule) and will be applied to the Base Fixed Energy, FAC, and Non-FAC PPA charges for the Smelters.

VI. <u>ES MONTHLY REPORTS</u>

Q. Is Big Rivers proposing any changes to the monthly reports used for calculating the monthly environmental surcharge?

A. Yes. Big Rivers is proposing changes to the forms in the monthly reports that Big Rivers files with the Commission. The revisions are needed to accommodate the inclusion of projects in the 2012 Plan proposed by Big Rivers. The current ES Monthly Report is attached as Exhibit Wolfram-4, and the proposed ES Monthly Report is attached as Exhibit Wolfram-5. The forms in Exhibit Wolfram-5 reflect the two major changes to the calculation methodology discussed herein (*i.e.* the addition of a component to E(m) to recover the fixed costs of the projects in the 2012 Plan, and the change to the cost allocation method from a "per-kWh" basis to a "percentage of Total Adjusted Revenue" basis).

Q. Please describe the detailed support forms that Big Rivers will file each month, as attached in Exhibit Wolfram-5.

A. Exhibit Wolfram-5 shows the detailed support forms that Big Rivers will file each month for reporting purposes.

1) ES Form 1.00 shows the calculation of the monthly billed Environmental Surcharge Factor ("MESF") for the expense month, where MESF equals the CESF less the Base Environmental Surcharge Factor ("BESF") (which is currently zero for Big Rivers).

2) ES Form 1.10 shows the calculation of the Total E(m) and Jurisdictional Surcharge Billing Factor for the expense month.

3) ES Form 2.0 shows the Determination of Environmental Compliance Rate Base and Determination of the Pollution Control Operating Expenses, Gross Proceeds from By-Product and Emission Allowance Sales, and the amortization of the Over/Under Recovery due to timing effects.

4) ES Form 2.10 shows the determination of Eligible Plant in Service, Depreciation and Amortization Expense, Taxes and Insurance Expense.

5) ES Form 2.20 shows the determination of Inventories of Spare Parts, reagents, etc.

6) ES Form 2.30 shows the inventory of Emission Allowances.

7) ES Form 2.31 shows the inventory of SO_2 Emission Allowances for the current vintage year and how the monthly Allowance expense is calculated.

8) ES Form 2.32 shows the inventory of NO_X Emission Allowances for the ozone season allowance allocation and how the monthly Allowance expense is calculated.

9) ES Form 2.33 shows the inventory of NO_X Emission Allowances for the annual allowance allocation and how the monthly Allowance expense is calculated.

10) ES Form 2.4 shows the incremental O&M expenses and the Determination of Cash Working Capital.

11) ES Form 2.5 shows the calculation of monthly O&M expenses associated with the pollution control equipment.

12) ES Form 3.00 shows the derivation of R(m), the average adjusted monthly revenue and the determination of the Jurisdictional Allocation Ratio for the current month.

13) ES Form 3.10 shows additional detail of the calculation of revenues used in the derivation of R(m) for the current month.

Q. Are the proposed Big Rivers monthly reports generally consistent with previous Commission Orders?

A. Yes. The proposed Big Rivers forms are generally consistent with the Commission-approved monthly reports of other electric utilities, including EKPC, LG&E and KU.

Q. Do the proposed Big Rivers monthly reports allow for any retirements associated with the 2012 Plan, as described in the direct testimony of Mr. Hite?

A. Yes. Any retirements will be captured in the monthly reports when such retirements are reflected on Big Rivers' books and records. Big Rivers will adjust the monthly ES filings to reflect the reduced depreciation expense associated with asset retirements in the Environmental Surcharge Monthly Report, ES Form 2.00.

VII. <u>IMPACT ON MEMBER BILLS</u>

Q. Did Big Rivers estimate the rate impact of the new projects in the 2012 Plan on the environmental surcharge?

A. Yes. The estimated annual impact on member bills associated with the projects included in the 2012 Plan are provided for each rate class in Exhibit Wolfram-6. Impacts are shown both before and after the offsetting effect of the Member Rate Stability Mechanism ("MRSM") and the Rural

Economic Reserve ("RER") tariff rider. In 2016, when the projects in the 2012 Plan should be complete, total billings to each rate class will increase by approximately 6.9% relative to projected 2016 billings absent the 2012 Plan, and by approximately 7.8% relative to projected 2012 billings.

Q. Will the Rurals experience any immediate billing impact due to the 2012 Plan?

A. No. The MRSM draws from an Economic Reserve account that Big Rivers established at the closing of the unwind transaction that was approved by the Commission in Case No. 2007-00455 to mitigate FAC and ES charges to members taking service under Rate Schedules RDS, LIC, and LICX (but only for Rate Schedule LICX to the extent of service priced under Rate Schedule LIC), which would include the Rurals. The RER draws from a RER account that Big Rivers established at the closing of the unwind transaction to mitigate FAC and ES charges to the Rurals after the Economic Reserve is depleted. The MRSM and the RER rider will entirely mitigate the bill impact of the 2012 Plan on the Rurals until the Economic Reserve and RER accounts are depleted.

Q. What is the effect of the 2012 Plan on the MRSM and the Rural Economic Reserve balance?

A. The increase in the ES tariff charges associated with the 2012 Plan causes Big Rivers to draw down the balance in the Economic Reserve and RER accounts faster than would be done absent the 2012 Plan. Without the

2012 Plan, the accounts are currently projected to be depleted in 2019; with the 2012 Plan, according to the projections in the environmental cost plan financial model, the accounts will be depleted in 2018. While other factors may affect the exact timing of the expiration of Economic Reserve and RER funds, Big Rivers expects the 2012 Plan to cause the Economic Reserve and RER accounts to run out approximately one year sooner than they otherwise would.

VIII. RECOMMENDATION AND CONCLUSION

Q. What is your recommendation to the Commission?

A. Based on my testimony, I recommend that the Commission approve Big Rivers' 2012 Plan, grant the requested certificates of public convenience and necessity, and approve the proposed ES tariff, other tariff revisions, and monthly reports as filed.

Q. Does this conclude your testimony?

A. Yes, it does.

BIG RIVERS ELECTRIC CORPORATION

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

CASE NO. 2012-00063

VERIFICATION

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

John Wolfram

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by John Wolfram on this the 26th day of March, 2012.

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

QUALIFICATIONS OF JOHN WOLFRAM

Summary of Qualifications

Provides consulting services to numerous investor-owned utilities, rural electric cooperatives, and municipal utilities regarding utility rate and regulatory filings, cost of service and wholesale and retail rate designs; and develops revenue requirements for utilities in general rate cases, including the preparation of analyses supporting pro-forma adjustments and the development of rate base.

Employment

The Prime Group, LLC — 2010 - Present
Senior Consultant

Provides consulting services in the areas of tariff development, regulatory analysis, revenue requirements, cost of service, rate design, and other utility regulatory areas.

Assists utilities with developing strategic marketing plans and implementation of those plans. Provides utility clients assistance regarding regulatory policy and strategy; project management support for utilities involved in complex regulatory proceedings; process audits; state and federal regulatory filing development; cost of service development and support; the development of innovative rates to achieve strategic objectives; unbundling of rates and the development of menus of rate alternatives for use with customers; energy efficiency program development.

Prepared retail and wholesale rate schedules and filings submitted to the Federal Energy Regulatory Commission (FERC), state regulatory commissions, and/or Boards of Directors for numerous electric and gas utilities.

E.ON U.S., LLC , Louisville, KY — 1997 - 2010
(Louisville Gas & Electric Company and Kentucky Utilities Company)
Director, Customer Service & Marketing (2006 - 2010)
Manager, Regulatory Affairs (2001 - 2006)
Lead Planning Engineer, Generation Planning (1998 - 2001)
Power Trader, LG&E Energy Marketing (1997 - 1998)

PJM INTERCONNECTION, LLC, Norristown, PA — 1990 - 1993; 1994 - 1997
Project Lead - PJM Wholesale Energy Market Information System

CINCINNATI GAS & ELECTRIC COMPANY, Cincinnati, OH — 1993 - 1994
Electrical Engineer - Energy Management System

Education

Bachelor of Science Degree in Electrical Engineering, University of Notre Dame, 1990
Master of Science Degree in Electrical Engineering, Drexel University, 1997
Leadership Louisville, 2006

Associations

Member of the Institute of Electrical and Electronics Engineers (IEEE)
Member, IEEE Power Engineering Society

Expert Witness Testimony

FERC: Submitted remarks and served on expert panel in FERC Docket No. RM01-10-000 on May 21, 2002 in Standards of Conduct for Transmission Providers staff conference, regarding proposed rulemaking on the functional separation of wholesale transmission and bundled sales functions for electric and gas utilities.

Kentucky: Submitted direct testimony for Louisville Gas & Electric Company and Kentucky Utilities Company in Case No. 2002-00029 regarding a Certificate of Public Convenience and Necessity for the acquisition of two combustion turbines.

Submitted direct testimony for Louisville Gas & Electric Company and Kentucky Utilities Company in Case No. 2002-00381 regarding a Certificate of Public Convenience and Necessity for the acquisition of four combustion turbines.

Presented company position for Louisville Gas & Electric Company and Kentucky Utilities Company at public meetings held in Case Nos. 2005-00142 and 2005-00154 regarding routes for proposed transmission lines.

Submitted discovery responses for Louisville Gas & Electric Company and Kentucky Utilities Company in Case No. 2005-00162 regarding the 2005 Joint Integrated Resource Plan.

Submitted discovery responses for Kentucky Utilities in Case No. 2005-00405 regarding the transfer of a utility hydroelectric power plant to a private hydroelectric power developer.

Submitted direct testimony for Louisville Gas & Electric Company and Kentucky Utilities Company in Case No. 2005-00467 and 2005-00472 regarding a Certificate of Public Convenience and Necessity for the construction of transmission facilities.

Submitted direct testimony for Louisville Gas & Electric Company and Kentucky Utilities Company in Case No. 2007-00067 for approval of a proposed Green Energy program and associated tariff riders.

Submitted direct testimony for Louisville Gas & Electric Company and Kentucky Utilities Company in Case No. 2007-00319 for the review, modification, and continuation of Energy Efficiency Programs and DSM Cost Recovery Mechanisms.

Submitted discovery responses for Louisville Gas & Electric Company and Kentucky Utilities Company in Administrative Case No. 2007-00477 regarding an investigation of the energy and regulatory issues in Kentucky's 2007 Energy Act.

Submitted discovery responses for Louisville Gas & Electric Company and Kentucky Utilities Company in Case No. 2008-00148 regarding the 2008 Joint Integrated Resource Plan.

Submitted discovery responses for Kentucky Utilities and/or Louisville Gas & Electric Company in various customer inquiry matters, including Case Nos. 2009-00421, 2009-00312, and 2009-00364.

Submitted direct testimony for Louisville Gas & Electric Company in Case No. 2009-00549 and for Kentucky Utilities Company in Case No. 2009-00548 for adjustment of electric and gas base rates, in support of a new service offering for Low Emission Vehicles, revised special charges, and company offerings aimed at assisting customers or enhancing customer service.

Submitted direct, rebuttal, and rehearing direct testimony on behalf of Big Rivers Electric Corporation in Case No. 2011-00036 Corporation regarding revenue requirements and pro forma adjustments.

Virginia: Submitted direct testimony for Kentucky Utilities Company d/b/a Old Dominion Power in Case No. PUE-2002-00570 regarding a Certificate of Public Convenience and Necessity for the acquisition of four combustion turbines.

Case No. 2012-00063
Exhibit Wolfram-2 – Proposed Big Rivers ES Tariff (*Start*)

For All Territory Served By
Cooperative's Transmission System
P.S.C. KY. No. 24

First Revised SHEET NO. 3

Big Rivers Electric Corporation
(Name of Utility)

CANCELLING P.S.C. KY. No. 24

Original SHEET NO. 3

RATES, TERMS AND CONDITIONS – SECTION 1

STANDARD RATE – RDS – *Rural Delivery Service*
Billing Form

[T]

INVOICE
BIG RIVERS ELECTRIC CORP. P O BOX 24 HENDERSON, KY 42419-0024
MONTH ENDING mm/dd/yy

TO: Member's Name ACCOUNT
SERVICE FROM: mm/dd/yyyy THRU mm/dd/yyyy BILLED PEAK mm/dd Time

SUBSTATION	BILLED KW	KWH	L.F. COIN	PREVIOUS READING	PRESENT READING	DIFF.	KW / KWH MULT.
Name	0,000	0,000,000	00.00	000000.000	000000.000	00000.000	1000
Name	0,000	0,000,000	00.00	000000.000	000000.000	00000.000	1000
TOTAL	0,000	0,000,000					

ACTUAL DEMAND	______	kW TIMES	$0.00	EQUALS	$00.00
ADJUSTMENT		kW TIMES	$0.00	EQUALS	$00.00
ENERGY	______	kWh TIMES	$0.00	EQUALS	$00.00
FUEL ADJUSTMENT CLAUSE	______	kWh TIMES	$0.00	EQUALS	$00.00
NSNFP	______	kWh TIMES	$0.00	EQUALS	$00.00
				SUBTOTAL	$00.00
ENVIRONMENTAL SURCHARGE	$00.00	TIMES	0.00%	EQUALS	$00.00
POWER FACTOR PENALTY	______	kW TIMES	$0.00	EQUALS	$00.00
UNWIND SURCREDIT	______	kWh TIMES	$0.00	EQUALS	$00.00
MEMBER RATE STABILITY MECHANISM	______	AMOUNT			$00.00
REBATE ADJUSTMENT	______	AMOUNT			$00.00
RURAL ECONOMIC RESERVE	______	AMOUNT			$00.00
CSR	______	AMOUNT			$00.00
RRES		kWh TIMES	$0.00	EQUALS	$00.00
ADJUSTMENT	______	kWh TIMES	$0.00	EQUALS	$00.00
				TOTAL AMOUNT DUE	$00.00

[T]

[T]

---- LOAD FACTOR ----		---- POWER FACTOR ----			
COIN	BILLED	BASE	AVERAGE	@ PEAK	MILLS PER KWH
00.00%	00.00%	00.00%	00.00%	00.00%	00.00

DUE IN IMMEDIATELY AVAILABLE FUNDS ON OR BEFORE THE FIRST WORKING DAY AFTER THE 24TH OF THE MONTH

DATE OF ISSUE April 2, 2012 DATE EFFECTIVE May 2, 2012

Mark A. Bailey

ISSUED BY Mark A. Bailey, President and Chief Executive Officer
Big Rivers Electric Corporation, 201 Third Street, Henderson, KY 42420

For All Territory Served By
Cooperative's Transmission System
P.S.C. KY. No. 24

First Revised SHEET NO. 8

Big Rivers Electric Corporation
(Name of Utility)

CANCELLING P.S.C. KY. No. 24

Original SHEET NO. 8

RATES, TERMS AND CONDITIONS – SECTION 1

STANDARD RATE – LIC – Large Industrial Customer
Billing Form

[T]

INVOICE
BIG RIVERS ELECTRIC CORP P O BOX 24 HENDERSON, KY 42419-0024
MONTH ENDING mm/dd/yy

TO: Member's Name ACCOUNT

SUBSTATION Substation Name SERVICE FROM mm/dd/yy THRU mm/dd/yy

USAGE	DEMAND	TIME	DAY	METER	MULT	KW DEMAND
		00:00 A (or P)	Mm/dd		1000	00,000
	POWER FACTOR	BASE	PEAK	AVERAGE	BILLED	
		00 00%	00 00%	00 00%	PEAK	
ENERGY		PREVIOUS	PRESENT	DIFFERENCE	MULT	KWH USED
		00000 000	00000 000	0000 000	1000	00,000,000

[T]

ACTUAL DEMAND	0,000	kW TIMES	$00 0000000		EQUALS	$ 00,000 00
ADJUSTMENT	0,000	kW TIMES	$00 0000000		EQUALS	$ 00,000.00
				SUB-TOTAL		$ 00,000 00
ENERGY	0,000,000	kWh TIMES	$0 0000000		EQUALS	$ 00,000 00
FUEL ADJUSTMENT CLAUSE	0,000,000	kWh TIMES	$0 0000000		EQUALS	$ 00,000 00
NSNFP	0,000,000	kWh TIMES	$0 0000000		EQUALS	$ 00,000.00
				SUB-TOTAL		$ 00,000.00
ENVIRONMENTAL SURCHARGE	$0,000 00	TIMES	00%		EQUALS	$ 00,000 00
POWER FACTOR PENALTY	0,000	kW TIMES	$00 0000000		EQUALS	$ 00,000 00
UNWIND SURCREDIT	0,000,000	kWh TIMES	$0 0000000		EQUALS	$ 00,000 00-
MEMBER RATE STABILITY MECHANISM	0,000,000	AMOUNT				0,000 00-
CSR	0,000,000	AMOUNT				$ 00,000 00
RRES	0,000,000	kWh TIMES	$0 0000000		EQUALS	$ 00,000 00
REBATE ADJUSTMENT	0,000,000	AMOUNT				$ 00,000 00
ADJUSTMENT	0,000,000	kWh TIMES	$0 0000000		EQUALS	$ 00,000.00
				SUB-TOTAL		$ 00,000 00
					TOTAL AMOUNT DUE	$ 00,000.00

LOAD FACTOR		POWER FACTOR			
ACTUAL	BILLED	BASE	AVERAGE	@ PEAK	MILLS PER KWH
00 00%	00 00%	00 00%	00 00%	00 00%	00 00

DUE IN IMMEDIATELY AVAILABLE FUNDS ON OR BEFORE THE FIRST WORKING DAY AFTER THE 24TH OF THE MONTH

DATE OF ISSUE April 2, 2012 DATE EFFECTIVE May 2, 2012

Mark A. Bailey

ISSUED BY Mark A. Bailey, President and Chief Executive Officer
Big Rivers Electric Corporation, 201 Third Street, Henderson, KY 42420

STANDARD RATE – LICX – Large Industrial Customer Expansion
Billing Form [T]

INVOICE
BIG RIVERS ELECTRIC CORP P O BOX 24 HENDERSON, KY 42419-0024
MONTH ENDING mm/dd/yy

TO: LARGE INDUSTRIAL CUSTOMER EXPANSION ACCOUNT
DELIVERY POINTS SERVICE FROM mm/dd/yy THRU mm/dd/yy
USAGE:

USAGE	DEMAND	TIME	DAY	METER	MULT	KW DEMAND
		00:00 A (or P)	mm/dd		1000	00,000

	BASE	PEAK	AVERAGE	kW DEMAND BILLED
POWER FACTOR EXPANSION DEMAND	00 00%	00 00%	00 00%	000,000

	PREVIOUS	PRESENT	DIFFERENCE	MULT	KWH USED
ENERGY EXPANSION ENERGY	00000 000	00000 000	0000 000	1000	00,000,000

EXPANSION DEMAND & EXPANSION ENERGY						
EXPANSION DEMAND, INCLUDING LOSSES		kW	TIMES	$	EQUALS	$
EXPANSION ENERGY, INCLUDING LOSSES		kWh	TIMES	$	EQUALS	$
OTHER EXPANSION SERVICE CHARGES					EQUALS	$
SUBTOTAL						$
EXPANSION DEMAND TRANSMISSION						
LOAD RATIO SHARE OF NETWORK LOAD						$
EXPANSION DEMAND & EXPANSION ENERGY ANCILLARY SERVICES						
SCHEDULING SYSTEM CONTROL & DISPATCH SERVICE						$
REACTIVE SUPPLY & VOLTAGE CONTROL FROM GENERATION SOURCES SERVICE						$
REGULATION & FREQUENCY RESPONSIVE SERVICE						$
ENERGY IMBALANCE SERVICE						$
OPERATING RESERVE – SPINNING RESERVE SERVICE						$
OPERATING RESERVE – SUPPLEMENTAL RESERVE SERVICE						$
SUBTOTAL						$
BIG RIVERS ADDER						
EXPANSION DEMAND		kW	TIMES	$	EQUALS	$
FUEL ADJUSTMENT CLAUSE	0,000,000	kWh	TIMES	$0 0000000	EQUALS	$
NSNFP	0,000,000	kWh	TIMES	$0 0000000	EQUALS	$
					SUBTOTAL	$
ENVIRONMENTAL SURCHARGE	$00,000 00		TIMES	00 00%	EQUALS	$
EXPANSION DEMAND/ENERGY – POWER FACTOR PENALTY		kW	TIMES	$0 0000000	EQUALS	$
UNWIND SURCREDIT	0,000,000	kWh	TIMES	$0 0000000	EQUALS	$
MEMBER RATE STABILITY MECHANISM	0,000,000		AMOUNT			$
CSR	0,000,000		AMOUNT			$
RRES	0,000,000	kWh	TIMES	$0 0000000	EQUALS	$
REBATE ADJUSTMENT	0,000,000		AMOUNT			$
					TOTAL AMOUNT DUE	$

[T]

------------ LOAD FACTOR ------------

ACTUAL	BILLED	MILLS PER KWH
00 00%	00 00%	00 00

DUE IN IMMEDIATELY AVAILABLE FUNDS ON OR BEFORE THE FIRST WORKING DAY AFTER THE 24TH OF THE MONTH

ES - Environmental Surcharge: [T]

Applicability:
To all Big Rivers' Members. [T]

Availability:
The Environmental Surcharge ("ES") is mandatory to all Standard Rate Schedules listed in Section 1 of the General Index, and to the FAC and the Non-FAC PPA adjustment clauses, including service to the Smelters under the two Wholesale Electric Service Agreements each dated as of July 1, 2009, between Big Rivers and Kenergy with respect to service by Kenergy to the Smelters. [T] [T]

Rate: [T]
The ES shall provide for monthly adjustments based on a percent of revenues equal to the difference between the environmental compliance costs in the base period and in the current period based on the following formula:

[T][N]

CESF = Net Jurisdictional E(m)/Jurisdictional R(m)

MESF = CESF – BESF

MESF = Monthly Environmental Surcharge Factor
CESF = Current Environmental Surcharge Factor
BESF = Base Environmental Surcharge Factor of $0.00000/kWh

Where E(m) is the total of each approved environmental compliance plan revenue requirement of environmental costs for the current expense month and R(m) is the revenue for the current expense month as set forth below. [T]

Definitions:

[T][N]

(1) E(m) = [(RB/12)(RORB)] + OE – BAS

Where:

[T]

(a) RB is the Environmental Compliance Rate Base, defined as electric plant in service for applicable environmental projects adjusted for accumulated depreciation, cash working capital, spare parts inventory, and limestone inventory, and emission allowance inventory;

ES - Environmental Surcharge – (*continued*)

Definitions (*continued*): [T]

(b) RORB is the Rate of Return on the Environmental Compliance Rate Base, designated as the average cost of debt for environmental compliance plan projects approved by the Commission plus application of a Times Interest Earned Ratio of 1.24; [T]

(c) OE represents the Monthly Pollution Control Operating Expenses, defined as the operating and maintenance expense and emission allowance expense of approved environmental compliance plans; and [T]

(d) BAS is the net proceeds from By-Products and Emission Allowance Sales. [T]

(2) Total E(m) is multiplied by the Jurisdictional System Allocation Ratio to arrive at Jurisdictional E(m). The Jurisdictional Allocation Ratio is the ratio of the 12-month total revenue from sales to Members to which the ES will be applied ending with the current expense month, divided by the 12-month total revenue from sales to Members and off-system sales for the current expense month. [T]

(3) The revenue R(m) is the average monthly revenue, including base revenues and automatic adjustment clause revenue less Environmental Cost Recovery Surcharge revenues, for Big Rivers for the twelve months ending with the current expense month.

(4) Jurisdictional E(m) is adjusted for Over/(Under) Recovery and, if ordered by the Public Service Commission, a Prior Period Adjustment to arrive at Net Jurisdictional E(m). [T]

(5) The current expense month (m) shall be the second month preceding the month in which the ES is billed. [T]

Case No. 2012-00063
Exhibit Wolfram-2 – Proposed Big Rivers ES Tariff (*End*)

For All Territory Served By
Cooperative's Transmission System
P.S.C. KY. No. 24

First Revised SHEET NO. 3

Big Rivers Electric Corporation
(Name of Utility)

CANCELLING P.S.C. KY. No. 24

Original SHEET NO. 3

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RATES, TERMS AND CONDITIONS – SECTION 1

STANDARD RATE – RDS – Rural Delivery Service
Billing Form [T]

INVOICE
BIG RIVERS ELECTRIC CORP P. O. BOX 24 HENDERSON KY 42419-0024
MONTH ENDING mm/dd/yy

TO: Member's Name ACCOUNT
SERVICE FROM: mm/dd/yyyy THRU mm/dd/yyyy BILLED PEAK mm/dd Time

SUBSTATION	BILLED KW	KWH	L.F. COIN	PREVIOUS READING	PRESENT READING	DIFF.	KW / KWH MULT
Name	0.000	0.000.000	00.00	000000.000	000000.000	00000.000	1000
Name	0.000	0.000.000	00.00	000000.000	000000.000	00000.000	1000
TOTAL	0.000	0.000.000					

ACTUAL DEMAND	______	kW TIMES	$0.00	EQUALS	$00.00 [T]
ADJUSTMENT		kW TIMES	$0.00	EQUALS	$00.00
ENERGY	______	kWh TIMES	$0.00	EQUALS	$00.00
FUEL ADJUSTMENT CLAUSE	______	kWh TIMES	$0.00	EQUALS	$00.00
NSNFP	______	kWh TIMES	$0.00	EQUALS	$00.00
				SUBTOTAL	$00.00
ENVIRONMENTAL SURCHARGE	$00.00	TIMES	0.00%	EQUALS	$00.00
POWER FACTOR PENALTY	______	KW TIMES	$0.00	EQUALS	$00.00
UNWIND SURCREDIT	______	kWh TIMES	$0.00	EQUALS	$00.00
MEMBER RATE STABILITY MECHANISM	______	AMOUNT			$00.00
REBATE ADJUSTMENT	______	AMOUNT			$00.00 [T]
RURAL ECONOMIC RESERVE	______	AMOUNT			$00.00
CSR	______	AMOUNT			$00.00
RRES		kWh TIMES	$0.00	EQUALS	$00.00
ADJUSTMENT	______	kWh TIMES	$0.00	EQUALS	$00.00
				TOTAL AMOUNT DUE	$00.00

Deleted: ¶ POWER FACTOR¶ PENALTY
Deleted: kWh TIMES
Deleted: $0.00
Deleted: ¶ NSNFP

LOAD FACTOR		POWER FACTOR			
COIN	BILLED	BASE	AVERAGE	@ PEAK	MILLS PER KWH
00.00%	00.00%	00.00%	00.00%	00.00%	00.00

DUE IN IMMEDIATELY AVAILABLE FUNDS ON OR BEFORE THE FIRST WORKING DAY AFTER THE 24TH OF THE MONTH

Deleted: December 20, 2011
Deleted: September 1, 2011
Deleted: *Issued by Authority of Orders of the Public Service Commission in Case No. 2011-00036 dated November 17, 2011, and December 14, 2011.*

DATE OF ISSUE April 2, 2012 DATE EFFECTIVE May 2, 2012

ISSUED BY Mark A. Bailey, President and Chief Executive Officer
Big Rivers Electric Corporation, 201 Third Street, Henderson, KY 42420

For All Territory Served By
Cooperative's Transmission System
P.S.C. KY. No. 24

First Revised SHEET NO. 8

Big Rivers Electric Corporation
(Name of Utility)

CANCELLING P.S.C. KY. No. 24

Original SHEET NO. 8

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RATES, TERMS AND CONDITIONS – SECTION 1

STANDARD RATE – LIC – Large Industrial Customer
Billing Form

[T]

INVOICE
BIG RIVERS ELECTRIC CORP P. O BOX 24 HENDERSON, KY 42419-0024
MONTH ENDING mm/dd/yy

TO:	Member's Name		ACCOUNT					
SUBSTATION	Substation Name			SERVICE FROM	mm/dd/yy	THRU	mm/dd/yy	
USAGE	DEMAND	TIME	DAY	METER	MULT	KW DEMAND		
		00:00 A (or P)	Mm/dd		1000	00.000		
	POWER FACTOR	BASE	PEAK	AVERAGE	BILLED			
		00 00%	00 00%	00 00%	PEAK			
ENERGY		PREVIOUS	PRESENT	DIFFERENCE	MULT	KWH USED		
		00000 000	00000 000	0000 000	1000	00.000.000		
ACTUAL DEMAND		0.000	kW TIMES	$00 0000000		EQUALS	$	00,000 00
ADJUSTMENT		0.000	kW TIMES	$00 0000000		EQUALS	$	00,000.00
				SUB-TOTAL			$	00 000 00
ENERGY		0 000.000	kWh TIMES	$0 0000000		EQUALS	$	00,000 00
FUEL ADJUSTMENT CLAUSE		0.000,000	kWh TIMES	$0 0000000		EQUALS	$	00 000 00
NSNFP		0.000.000	kWh TIMES	$0.0000000		EQUALS	$	00.000.00
				SUB-TOTAL			$	00.000.00
ENVIRONMENTAL SURCHARGE		$0,000.00	TIMES	00%		EQUALS	$	00.000.00
POWER FACTOR PENALTY		0.000	kW TIMES	$00 0000000		EQUALS	$	00 000 00
UNWIND SURCREDIT		0.000.000	kWh TIMES	$0 0000000		EQUALS	$	00.000 00-
MEMBER RATE STABILITY MECHANISM								
		0.000,000	AMOUNT					0,000 00-
CSR		0 000.000	AMOUNT				$	00 000 00
RRES		0.000,000	kWh TIMES	$0 0000000		EQUALS	$	00,000 00
REBATE ADJUSTMENT		0 000.000	AMOUNT				$	00,000 00
ADJUSTMENT		0.000.000	kWh TIMES	$0 0000000		EQUALS	$	00,000.00
				SUB-TOTAL			$	00 000 00
					TOTAL AMOUNT DUE		$	00,000.00

[T]

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LOAD FACTOR		POWER FACTOR			
ACTUAL	BILLED	BASE	AVERAGE	@ PEAK	MILLS PER KWH
00 00%	00 00%	00 00%	00 00%	00 00%	00 00

DUE IN IMMEDIATELY AVAILABLE FUNDS ON OR BEFORE THE FIRST WORKING DAY AFTER THE 24[TH] OF THE MONTH

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Deleted: September 1, 2011

Deleted: *Issued by Authority of Orders of the Public Service Commission in Case No. 2011-00036 dated November 17, 2011, and December 14, 2011.*

DATE OF ISSUE April 2, 2012 DATE EFFECTIVE May 2, 2012

ISSUED BY Mark A. Bailey, President and Chief Executive Officer
Big Rivers Electric Corporation, 201 Third Street, Henderson, KY 42420

Case No. 2012-00063
Exhibit Wolfram -3

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RATES, TERMS AND CONDITIONS – SECTION 1

STANDARD RATE – LICX – Large Industrial Customer Expansion
Billing Form

[T]

INVOICE
BIG RIVERS ELECTRIC CORP P. O. BOX 24 HENDERSON, KY 42419-0024
MONTH ENDING mm/dd/yy

TO: LARGE INDUSTRIAL CUSTOMER EXPANSION ACCOUNT
DELIVERY
POINTS SERVICE FROM mm/dd/yy THRU mm/dd/yy
USAGE:

USAGE	DEMAND	TIME	DAY	METER	MULT	KW DEMAND
		00:00 A (or P)	mm/dd		1000	00,000

	BASE	PEAK	AVERAGE		kW DEMAND BILLED
POWER FACTOR EXPANSION DEMAND	00.00%	00.00%	00.00%		000,000

	PREVIOUS	PRESENT	DIFFERENCE	MULT	KWH USED
ENERGY EXPANSION ENERGY	00000.000	00000.000	0000.000	1000	00,000,000

EXPANSION DEMAND & EXPANSION ENERGY						
EXPANSION DEMAND, INCLUDING LOSSES		kW	TIMES	$	EQUALS	$
EXPANSION ENERGY, INCLUDING LOSSES		kWh	TIMES	$	EQUALS	$
OTHER EXPANSION SERVICE CHARGES					EQUALS	$
SUBTOTAL						$
EXPANSION DEMAND TRANSMISSION						
LOAD RATIO SHARE OF NETWORK LOAD						$
EXPANSION DEMAND & EXPANSION ENERGY ANCILLARY SERVICES						
SCHEDULING SYSTEM CONTROL & DISPATCH SERVICE						$
REACTIVE SUPPLY & VOLTAGE CONTROL FROM GENERATION SOURCES SERVICE						$
REGULATION & FREQUENCY RESPONSIVE SERVICE						$
ENERGY IMBALANCE SERVICE						$
OPERATING RESERVE – SPINNING RESERVE SERVICE						$
OPERATING RESERVE – SUPPLEMENTAL RESERVE SERVICE						$
SUBTOTAL						$
BIG RIVERS ADDER						
EXPANSION DEMAND		kW	TIMES	$	EQUALS	$
FUEL ADJUSTMENT CLAUSE	0,000,000	kWh	TIMES	$0.0000000	EQUALS	$
NSNFP	0,000,000	kWh	TIMES	$0.0000000	EQUALS	$
					SUBTOTAL	$
ENVIRONMENTAL SURCHARGE	$00,000.00		TIMES	00.00%	EQUALS	$
EXPANSION DEMAND/ENERGY – POWER FACTOR PENALTY		kW	TIMES	$0.0000000	EQUALS	$
UNWIND SURCREDIT	0,000,000	kWh	TIMES	$0.0000000	EQUALS	$
MEMBER RATE STABILITY MECHANISM	0,000,000	AMOUNT				$
CSR	0,000,000	AMOUNT				$
RRES	0,000,000	kWh	TIMES	$0.0000000	EQUALS	$
REBATE ADJUSTMENT	0,000,000	AMOUNT				$
					TOTAL AMOUNT DUE	$

[T]

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POWER FACTOR PENALTY

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---------- LOAD FACTOR ----------			
ACTUAL	BILLED		MILLS PER KWH
00.00%	00.00%		00.00

DUE IN IMMEDIATELY AVAILABLE FUNDS ON OR BEFORE THE FIRST WORKING DAY AFTER THE 24TH OF THE MONTH

DATE OF ISSUE April 2, 2012 DATE EFFECTIVE May 2, 2012

ISSUED BY Mark A. Bailey, President and Chief Executive Officer
Big Rivers Electric Corporation, 201 Third Street, Henderson, KY 42420

For All Territory Served By
Cooperative's Transmission System
P.S.C. KY. No. 24

First Revised SHEET NO. 46

Big Rivers Electric Corporation
(Name of Utility)

CANCELLING P.S.C. KY. No. 24

Original SHEET NO. 46

RATES, TERMS AND CONDITIONS – SECTION 2

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ES - Environmental Surcharge: [T]

Applicability:
To all Big Rivers' Members. [T]

Availability:
The Environmental Surcharge ("ES") is mandatory to all Standard Rate Schedules listed in Section 1 of the General Index, and to the FAC and the Non-FAC PPA adjustment clauses, including service to the Smelters under the two Wholesale Electric Service Agreements each dated as of July 1, 2009, between Big Rivers and Kenergy with respect to service by Kenergy to the Smelters. [T] [T]

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Deleted: , but excluding (i) Supplemental and Back-Up Energy sales to the Smelters under those two agreements and (ii) Backup Power Service and Energy Imbalance Service to Kenergy for Domtar Paper Company, LLC (in the aggregate, "Jurisdictional Sales")

Rate: [T]
The ES shall provide for monthly adjustments based on a percent of revenues equal to the difference between the environmental compliance costs in the base period and in the current period based on the following formula: [T][N]

Deleted: charge per kWh
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CESF = Net Jurisdictional E(m)/Jurisdictional R(m)

MESF = CESF – BESF

MESF = Monthly Environmental Surcharge Factor
CESF = Current Environmental Surcharge Factor
BESF = Base Environmental Surcharge Factor of $0.00000/kWh

Where E(m) is the total of each approved environmental compliance plan revenue requirement of environmental costs for the current expense month and R(m) is the revenue for the current expense month as set forth below. [T]

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Deleted: kWh sales

Definitions: [T][N]

(1) E(m) = [(RB/12)(RORB)] + OE – BAS

Where:

(a) RB is the Environmental Compliance Rate Base, defined as electric plant in service for applicable environmental projects adjusted for accumulated depreciation, cash working capital, spare parts inventory, and limestone inventory, and emission allowance inventory; [T]

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DATE OF ISSUE April 2, 2012 DATE EFFECTIVE May 2, 2012

ISSUED BY Mark A. Bailey, President and Chief Executive Officer
Big Rivers Electric Corporation, 201 Third Street, Henderson, KY 42420

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ES - Environmental Surcharge – (*continued*)

Definitions (*continued*): [T]

(b) RORB is the Rate of Return on the Environmental Compliance Rate Base, designated as the average cost of debt for environmental compliance plan projects approved by the Commission plus application of a Times Interest Earned Ratio of 1.24; [T]

(c) OE represents the Monthly Pollution Control Operating Expenses, defined as the operating and maintenance expense and emission allowance expense of approved environmental compliance plans; and [T]

(d) BAS is the net proceeds from By-Products and Emission Allowance Sales. [T]

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(2) Total E(m) is multiplied by the Jurisdictional System Allocation Ratio to arrive at Jurisdictional E(m). The Jurisdictional Allocation Ratio is the ratio of the 12-month total revenue from sales to Members to which the ES will be applied ending with the current expense month, divided by the 12-month total revenue from sales to Members and off-system sales for the current expense month. [T]

Deleted: kWh ¶
Jurisdictional Sales

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Deleted: sum of kWh of (i) Jurisdictional Sales, (ii) off-system sales, (iii) ¶
Supplemental and Back-Up sales to the Smelters, and (iv) Backup Power Service and Energy Imbalance Service to Kenergy for Domtar Paper Company, LLC

(3) The revenue R(m) is the average monthly revenue, including base revenues and automatic adjustment clause revenue less Environmental Cost Recovery Surcharge revenues, for Big Rivers for the twelve months ending with the current expense month.

(4) Jurisdictional E(m) is adjusted for Over/(Under) Recovery and, if ordered by the Public Service Commission, a Prior Period Adjustment to arrive at Net Jurisdictional E(m). [T]

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(5) The current expense month (m) shall be the second month preceding the month in which the ES is billed. [T]

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Deleted: September 1, 2011

Deleted: *Issued by Authority of Orders of the Public Service Commission in Case No. 2011-00036 dated November 17, 2011, and December 14, 2011.*

BIG RIVERS ELECTRIC CORP
ENVIRONMENTAL SURCHARGE REPORT

Calculation of Monthly Billed Environmental Surcharge Factor - MESF
For the Expense Month:

MESF = CESF - BESF

Where:

CESF	=	Current Environmental Surcharge Factor
BESF	=	Base Environmental Surcharge Factor

Calculation of MESF:

CESF, from ES Form 1.10	=	$0.000000
BESF	=	$0.000000
MESF	=	$0.000000

Effective Date for Billing: February 1, 2012

Submitted by: ______________________

Title: Director, Finance

Date Submitted: ______________________

BIG RIVERS ELECTRIC CORP
ENVIRONMENTAL SURCHARGE REPORT

Calculation of Total E(m) and
Jurisdictional Surcharge Billing Factor

For the Expense Month:

Calculation of Total E(m)

E(m) =OE - BAS, where
OE = Pollution Control Operating Expenses
BAS = Total Proceeds from By-Product and Allowance Sales

			Environmental Compliance Plans
OE	=	$	-
BAS	=		-
E(m)	=	$	-

Calculation of Jurisdictional Environmental Surcharge Billing Factor

Jurisdictional Allocation Ratio for Expense Month	=		0.000000%
Jurisdictional E(m) = E(m) x Jurisdictional Allocation Ratio	=	$	-
Adjustment for Over/(Under) Recovery, from Form 2.00	=		-
Prior Period Adjustment	=		-
Net Jurisdictional E(m) = Jurisdictional E(m) plus Adjustment for Over/(Under) plus Prior Period Adjustment	=	$	-
Jurisdictional S(m) = Monthly Jurisdictional kWh Sales for the Month, from ES 3.00	=		-
Jurisdictional Environmental Surcharge Billing Factor: Net Jurisdictional E(m) / Jurisdictional S(m) ; Per kWh	=		**$0.000000**

ES FORM 2.00

BIG RIVERS ELECTRIC CORP
ENVIRONMENTAL SURCHARGE REPORT
Revenue Requirements of Environmental Compliance Costs
For the Expense Month:

Determination of Pollution Control Operating Expenses

	Environmental Compliance Plan
Monthly Operation & Maintenance Expense	$ -
Monthly Emission Allowance Expense from ES Form 2.31, 2.32 and 2.33	-
Total Pollution Control Operation Expense	$ -

Proceeds From By-Product and Allowance Sales

	Total Proceeds
Allowance Sales	$ -
Scrubber By-Products Sales	-
Total Proceeds from Sales	$ -

True-up Adjustment: Over/(Under) Recovery of Monthly Surcharge

B. Net Jurisdictional E(m) for two months prior to Expense Month	$ 0
D. E(m) recovered in month preceding Expense Month	0
E. Over/(Under) Recovery	$ 0
Over recovery will be deducted from Jurisdictional E(m); (Under) recovery will be added to Jurisdictional E(m)	

BIG RIVERS ELECTRIC CORP
ENVIRONMENTAL SURCHARGE REPORT

For the Expense Month:

Vintage Year	Number of Allowances			Total Dollar Value Of Vintage Year			Comments and Explanations
	SO_2	NOx Annual	NOx Ozone Season	SO_2	NOx Annual	NOx Ozone Season	EPA SO2 allotted thru 2040. EPA NOx allotted thru 2014.
2009							
2010							
2011							
2012							
2013							
2014							
2015							
2016							
2017							
2018							
2019							
2020							
2021							
2022							
2023							
2024							
2025							
2026							
2027							
2028							
2029							
2030							
2031							
2032							
2033							
2034							
2035							
2036							
2037							
2038							
2039							
2040							

Other than the assignment of allowances by EPA, inventory adjustments include but are not limited to, purchases, allowances acquired as part of other purchases and the sale of allowances

BIG RIVERS ELECTRIC CORP
ENVIRONMENTAL SURCHARGE REPORT
Inventory of Emission Allowances (SO_2) - Current Vintage Year

For the Expense Month:

	Beginning Inventory	Allocations/ Purchases	Utilized (Coal Fuel)	Utilized (Other Fuels)	Sold	Ending Inventory	Allocation, Purchase, or Sale Date & Vintage Years
TOTAL EMISSION ALLOWANCES IN INVENTORY, ALL CLASSIFICATIONS							
Quantity	0	0	0	0	0	0	
Dollars	$ -	$ -	$ -	$ -	$ -	$ -	
$/Allowance	$ -	$ -	$ -	$ -	$ -	$ -	
ALLOCATED ALLOWANCES FROM EPA: COAL FUEL							
Quantity						0	
Dollars						0	
ALLOCATED ALLOWANCES FROM EPA: OTHER FUELS							
Quantity	0	0	0	0	0	0	
Dollars	$ -	$ -	$ -	$ -	$ -	0	
ALLOWANCES FROM PURCHASES:							
From Market:							
Quantity	0	0	0	0	0	0	
Dollars	$ -	$ -	$ -	$ -	$ -	0	
$/Allowance	$ -	$ -	$ -	$ -	$ -	$ -	
From Big Rivers							
Quantity	0	0	0	0	0	0	
Dollars	$ -	$ -	$ -	$ -	$ -	0	
$/Allowance	$ -	$ -	$ -	$ -	$ -	$ -	

Emission Allowance Expense for Other Power Generation is excluded from expense reported on Form 2.00 for recovery through the monthly billing factor

BIG RIVERS ELECTRIC CORP
ENVIRONMENTAL SURCHARGE REPORT
Inventory of Emission Allowances (NOx) - Ozone Season Allowance Allocation

For the Expense Month:

	Beginning Inventory	Allocations/ Purchases (1)	Utilized (Coal Fuel)	Utilized (Other Fuels)	Sold	Ending Inventory	Allocation, Purchase, or Sale Date & Vintage Years
TOTAL EMISSION ALLOWANCES IN INVENTORY, ALL CLASSIFICATIONS							
Quantity	0	0	0	0	0	0	
Dollars	$ -	$ -	$ -	$ -	$ -	$ -	
$/Allowance	$ -	$ -	$ -	$ -	$ -	$ -	
ALLOCATED ALLOWANCES FROM EPA: COAL FUEL							
Quantity						0	
Dollars						0	
ALLOCATED ALLOWANCES FROM EPA: OTHER FUELS							
Quantity	0	0	0	0	0	0	
Dollars	$ -	$ -	$ -	$ -	$ -	0	
ALLOWANCES FROM PURCHASES:							
From Market:							
Quantity	0	0	0	0	0	0	
Dollars	$ -	$ -	$ -	$ -	$ -	0	
$/Allowance	$ -	$ -	$ -	$ -	$ -	$ -	
From Big Rivers:							
Quantity	0	0	0	0	0	0	
Dollars	$ -	$ -	$ -	$ -	$ -	0	
$/Allowance	$ -	$ -	$ -	$ -	$ -	$ -	

Emission Allowance Expense for Other Power Generation is excluded from expense reported on Form 2.00 for recovery through the monthly billing factor

BIG RIVERS ELECTRIC CORP
ENVIRONMENTAL SURCHARGE REPORT
Inventory of Emission Allowances (NOx) - Annual Allowance Allocation

For the Expense Month:

	Beginning Inventory	Allocations/ Purchases	Utilized (Coal Fuel)	Utilized (Other Fuels)	Sold	Ending Inventory	Allocation, Purchase, or Sale Date & Vintage Years
TOTAL EMISSION ALLOWANCES IN INVENTORY, ALL CLASSIFICATIONS							
Quantity	0	0	0	0	0	0	
Dollars	$ -	$ -	$ -	$ -	$ -	$ -	
$/Allowance	$ -	$ -	$ -	$ -	$ -	$ -	
ALLOCATED ALLOWANCES FROM EPA: COAL FUEL							
Quantity						0	
Dollars						0	
ALLOCATED ALLOWANCES FROM EPA: OTHER FUELS							
Quantity	0	0	0	0	0	0	
Dollars	$ -	$ -	$ -	$ -	$ -	0	
ALLOWANCES FROM PURCHASES:							
From Market:							
Quantity	0	0	0	0	0	0	
Dollars	$ -	$ -	$ -	$ -	$ -	0	
$/Allowance	$ -	$ -	$ -	$ -	$ -	$ -	
From Big Rivers:							
Quantity	0	0	0	0	0	0	
Dollars	$ -	$ -	$ -	$ -	$ -	0	
$/Allowance	$ -	$ -	$ -	$ -	$ -	$ -	

Emission Allowance Expense for Other Power Generation is excluded from expense reported on Form 2.00 for recovery through the monthly billing factor

ES FORM 2.50

BIG RIVERS ELECTRIC CORP
ENVIRONMENTAL SURCHARGE REPORT
Pollution Control - Operations & Maintenance Expenses
For the Expense Month:

O&M Expense Account	COLEMAN Station	GREEN Station	HMPL SII Station	WILSON Station	REID Station	TOTAL All Stations
NOx Plan						
Anhydrous Ammonia						-
Emulsified Sulphur for NOx						-
Individual Expense Account Items						-
Individual Expense Account Items						-
Total NOx Plan O&M Expenses	-	-	-	-	-	-
S02 Plan						
Disposal-Bottom Ash						-
Disposal-Fly Ash						-
Off Spec Gypsum						-
Fixation Lime						-
Disposal-Flyash/Bottom Ash/Sludge						-
Reagent-Calcium Oxide (landfill stabilization)						-
Reagent-Limestone						-
Reagent-Lime						-
Emulsified Sulphur for SO2						-
Reagent-DiBasic Acid						-
Reagent-Sodium BiSulfite for SO2						-
Total S02 Plan O&M Expenses	-	-	-	-	-	-
S03 Plan						
Hydrated Lime - SO3						-
Individual Expense Account Items						-
Individual Expense Account Items						-
Total S02 Plan O&M Expenses	-	-	-	-	-	-

Current Month O&M Expense for All Plans	-	-	-	-	-	-

BIG RIVERS ELECTRIC CORP
ENVIRONMENTAL SURCHARGE REPORT
kWh Sales Computation of (S) (m)

For the Expense Month:

(1) Member Sales (kWh)	-
(2) Base Energy Sales to Smelters (kWh)	-
(3) Subtotal Jurisdictional Sales (kWh)	-
(4) Off-System Sales (kWh)	-
(5) Supplemental and Backup Sales to Smelters & Backup and Energy Imbalance Sales to Domtar (kWh)	-
(6) Total	-
(7) Jurisdictional Allocation Percentage for Current Month Expense Month Kentucky Jurisdictional kWhs divided by Expense Month Total kWh Sales [(3)/(6)]	0.000000%

BIG RIVERS ELECTRIC CORP
ENVIRONMENTAL SURCHARGE REPORT

Calculation of Monthly Billed Environmental Surcharge Factor - MESF
For the Expense Month Ending

MESF = CESF - BESF

Where:

CESF	=	Current Environmental Surcharge Factor
BESF	=	Base Environmental Surcharge Factor

Calculation of MESF:

CESF, from ES Form 1.10	=	$0.000000
BESF	=	$0.000000
MESF	=	$0.000000

Effective Date for Billing:

Submitted by: ____________________

Title: Director, Finance

Date Submitted: ____________________

BIG RIVERS ELECTRIC CORP
ENVIRONMENTAL SURCHARGE REPORT

Calculation of Total E(m) and
Jurisdictional Surcharge Billing Factor

For the Expense Month Ending

Calculation of Total E(m)

1	E(m) =RORB + OE - BAS, where	______
	OE = Pollution Control Operating Expenses	______
	BAS = Total Proceeds from By-Product and Allowance Sales	______
	RORB = Rate Base * Rate of Return	______
2	Rate Base	______
3	Rate Base / 12	______
4	Rate of Return	______
5	Return on Rate Base (RORB)	______
6	Operating Expenses	______
7	By-Product and Emission Allowance Sales (BAS)	______
8	Sub-Total E(m)	______

Calculation of Jurisdictional Environmental Surcharge Billing Factor

9	Member System Allocation Ratio for the Month (Form 3 0)	______
10	Subtotal E(m) = Subtotal E(m) x Member System Allocation Ratio	______
11	Adjustment for (Over)/Under Recovery, as applicable	______
12	E(m) = Subtotal E(m) plus (Over)/Under Recovery	______
13	R(m) = Average Monthly Member System Revenue for the 12 Months Ending with the Current Expense Month (Form 3.0)	______
14	CESF: E(m) / R(m); as a % of Revenue	______

BIG RIVERS ELECTRIC CORP

ENVIRONMENTAL SURCHARGE REPORT

Revenue Requirements of Environmental Compliance Costs
For the Expense Month Ending

RORB
Determination of Environmental Compliance Rate Base

Eligible Pollution Control Plant (Gross Plant)	Form 2.20	
Additions:		
Inventory - Spare Parts	Form 2.20	
Inventory - Limestone	Form 2.21	
Inventory - Emission Allowances	Form 2.30	
Cash Working Capital Allowance	Form 2.33	
Subtotal		
Deductions:		
Accumulated Depreciation on Eligible Pollution Control Plant	Form 2.10	
Subtotal		
Environmental Compliance Rate Base		

RORB
Rate of Return on Rate Base

Weighted Average Cost of Debt for 2012 Plan	
Contract TIER	1.24
Rate of Return	

OE
Determination of Pollution Control Operating Expenses

Monthly Operation & Maintenance Expense	Form 2.50	
Monthly Depreciation and Amortization Expense	Form 2.10	
Monthly Taxes Other Than Income Taxes	Form 2.10	
Monthly Insurance Expense	Form 2.10	
Monthly Emission Allowance Expense from ES Form 2.31, 2.32 and 2.33	Forms 2.31, 2.32, 2.33	
Amortization of Regulatory Asset		
Total Pollution Control Operation Expense		

BAS
Proceeds From By-Product and Allowance Sales

Allowance Sales	
Scrubber By-Products Sales	
Total Proceeds from Sales	

True-up Adjustment: Over/(Under) Recovery of Monthly Surcharge

B. Net Jurisdictional E(m) for two months prior to Expense Month	
D. E(m) recovered in month preceding Expense Month	
E. Over/(Under) Recovery	
Over recovery will be deducted from Jurisdictional E(m); (Under) recovery will be added to Jurisdictional E(m)	

Form 2.10

Big Rivers Electric Corporation
Environmental Surcharge Report
Plant, Depreciation & Amortization, Taxes and Insurance Expenses
For the Month Ending

(1)	(2)	(3)	(4)	(5)	(6)	(7)
Description	Eligible Gross Plant in Service	Eligible Accum Depr & Amort	Eligible Net Plant in Service	Monthly Depr & Amort Expense	Monthly Taxes Expense	Monthly Insurance Expense
Total						

Big Rivers Electric Corporation
Environmental Surcharge Report

Form 2.20

Inventories of Spare Parts and Limestone
For the Month Ending

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Beginning Inventory	Purchases	Other Adjustments	Utilized	Ending Inventory	Reason(s) for Adjustment
					(2)+(3)+(4)-(5)	
Total						

BIG RIVERS ELECTRIC CORP
ENVIRONMENTAL SURCHARGE REPORT
Inventory and Expense of Emission Allowances

For the Month Ending

Vintage Year	Number of Allowances			Total Dollar Value Of Vintage Year			Comments and Explanations
	SO_2	NOx Annual	NOx Ozone Season	SO_2	NOx Annual	NOx Ozone Season	
2009							
2010							
2011							
2012							
2013							
2014							
2015							
2016							
2017							
2018							
2019							
2020							
2021							
2022							
2023							
2024							
2025							
2026							
2027							
2028							
2029							
2030							
2031							
2032							
2033							
2034							
2035							
2036							
2037							
2038							
2039							
2040							

Other than the assignment of allowances by EPA, inventory adjustments include, but are not limited to, purchases, allowances acquired as part of other purchases, and the sale of allowances.

ES FORM 2.31

BIG RIVERS ELECTRIC CORP
ENVIRONMENTAL SURCHARGE REPORT

Inventory of Emission Allowances (SO_2) - Current Vintage Year

For the Month Ending

	Beginning Inventory	Allocations/ Purchases	Utilized (Coal Fuel)	Utilized (Other Fuels)	Sold	Ending Inventory	Allocation, Purchase, or Sale Date & Vintage Years
TOTAL EMISSION ALLOWANCES IN INVENTORY, ALL CLASSIFICATIONS							
Quantity							
Dollars							
$/Allowance							
ALLOCATED ALLOWANCES FROM EPA: COAL FUEL							
Quantity							
Dollars							
ALLOCATED ALLOWANCES FROM EPA: OTHER FUELS							
Quantity							
Dollars							
ALLOWANCES FROM PURCHASES:							
From Market:							
Quantity							
Dollars							
$/Allowance							
From Big Rivers							
Quantity							
Dollars							
$/Allowance							

Emission Allowance Expense for Other Power Generation is excluded from expense reported on Form 2.00 for recovery through the monthly billing factor

ES FORM 2.32

BIG RIVERS ELECTRIC CORP
ENVIRONMENTAL SURCHARGE REPORT
Inventory of Emission Allowances (NOx) - Ozone Season Allowance Allocation

For The Month Ending

	Beginning Inventory	Allocations/ Purchases (1)	Utilized (Coal Fuel)	Utilized (Other Fuels)	Sold	Ending Inventory	Allocation, Purchase, or Sale Date & Vintage Years
TOTAL EMISSION ALLOWANCES IN INVENTORY, ALL CLASSIFICATIONS							
Quantity							
Dollars							
$/Allowance							
ALLOCATED ALLOWANCES FROM EPA: COAL FUEL							
Quantity							
Dollars							
ALLOCATED ALLOWANCES FROM EPA: OTHER FUELS							
Quantity							
Dollars							
ALLOWANCES FROM PURCHASES:							
From Market:							
Quantity							
Dollars							
$/Allowance							
From Big Rivers:							
Quantity							
Dollars							
$/Allowance							

Emission Allowance Expense for Other Power Generation is excluded from expense reported on Form 2.00 for recovery through the monthly billing factor.

ES FORM 2.33

BIG RIVERS ELECTRIC CORP
ENVIRONMENTAL SURCHARGE REPORT
Inventory of Emission Allowances (NOx) - Annual Allowance Allocation

For The Month Ending

	Beginning Inventory	Allocations/ Purchases	Utilized (Coal Fuel)	Utilized (Other Fuels)	Sold	Ending Inventory	Allocation, Purchase, or Sale Date & Vintage Years
TOTAL EMISSION ALLOWANCES IN INVENTORY, ALL CLASSIFICATIONS							
Quantity							
Dollars							
$/Allowance							
ALLOCATED ALLOWANCES FROM EPA: COAL FUEL							
Quantity							
Dollars							
ALLOCATED ALLOWANCES FROM EPA: OTHER FUELS							
Quantity							
Dollars							
ALLOWANCES FROM PURCHASES:							
From Market:							
Quantity							
Dollars							
$/Allowance							
From Big Rivers:							
Quantity							
Dollars							
$/Allowance							

Emission Allowance Expense for Other Power Generation is excluded from expense reported on Form 2.00 for recovery through the monthly billing factor.

BIG RIVERS ELECTRIC CORP
ENVIRONMENTAL SURCHARGE REPORT
O&M Expenses and Determination of Cash Working Capital Allowance

For the Expense Month Ending

2012 Plan

Eligible O&M Expenses	
11th previous month	
10th previous month	
9th previous month	
8th previous month	
7th previous month	
6th previous month	
5th previous month	
4th previous month	
3rd previous month	
2nd previous month	
Previous month	
Current month	
Total 12 Month O&M	
Average Monthly O&M	

Determination of Working Capital Allowance	
12 Months O&M Expense	-
One-Eighth (1/8) of 12 Month O&M Expenses	

ES FORM 2.50

BIG RIVERS ELECTRIC CORP
ENVIRONMENTAL SURCHARGE REPORT
Pollution Control - Operations & Maintenance Expenses
For the Expense Month Ending

O&M Expense Account	COLEMAN Station	GREEN Station	HMPL SII Station	WILSON Station	REID Station	TOTAL All Stations
2007 Plan						
NOx Plan						
Anhydrous Ammonia						
Emulsified Sulphur for NOx						-
Individual Expense Account Items						-
Individual Expense Account Items						-
Total NOx Plan O&M Expenses						-
S02 Plan						
Disposal-Bottom Ash						-
Disposal-Fly Ash						-
Off Spec Gypsum						-
Fixation Lime						-
Disposal-Flyash/Bottom Ash/Sludge						-
Reagent-Calcium Oxide (landfill stabilization)						-
Reagent-Limestone						-
Reagent-Lime						-
Emulsified Sulphur for SO2						-
Reagent-DiBasic Acid						-
Reagent-Sodium BiSulfite for SO2						-
Total S02 Plan O&M Expenses						-
S03 Plan						
Hydrated Lime - SO3						-
Individual Expense Account Items						-
Individual Expense Account Items						-
Total S02 Plan O&M Expenses	-	-	-	-	-	-

Case No. 2012-00063
Exhibit Wolram-5

ES FORM 2.50

BIG RIVERS ELECTRIC CORP
ENVIRONMENTAL SURCHARGE REPORT
Pollution Control - Operations & Maintenance Expenses
For the Expense Month Ending

O&M Expense Account	COLEMAN Station	GREEN Station	HMPL SII Station	WILSON Station	REID Station	TOTAL All Stations
2012 Plan						
Project 4 - Wilson FGD						
						-
						-
						-
Total Project 4 O&M Expenses				-		-
Project 5 - Green Unit 2 SCR						
						-
						-
						-
Total Project 5 O&M Expenses		-				-
Project 6 - Reid Unit 1 Conversion						
						-
						-
						-
Total Project 6 O&M Expenses					-	-
Project 7 - HMP&L Recycle Pump & ID Fan Motors						
						-
						-
						-
Total Project 7 O&M Expenses			-			-

ES FORM 2.50

BIG RIVERS ELECTRIC CORP
ENVIRONMENTAL SURCHARGE REPORT
Pollution Control - Operations & Maintenance Expenses
For the Expense Month Ending

O&M Expense Account	COLEMAN Station	GREEN Station	HMPL SII Station	WILSON Station	REID Station	TOTAL All Stations
Project 8 - Coleman Hg						
						-
						-
						-
Total Project 8 O&M Expenses	-					-
Project 9 - Wilson Hg						
						-
						-
						-
Total Project 9 O&M Expenses				-		-
Project 10 - Green Hg						
						-
						-
						-
Total Project 10 O&M Expenses		-				-
Project 11 - HMP&L Hg						
						-
						-
						-
Total Project 11 O&M Expenses			-			-

Case No. 2012-00063
Exhibit Wolram-5
Page 13 of 16

ES FORM 2.50

BIG RIVERS ELECTRIC CORP
ENVIRONMENTAL SURCHARGE REPORT
Pollution Control - Operations & Maintenance Expenses
For the Expense Month Ending

O&M Expense Account	COLEMAN Station	GREEN Station	HMPL SII Station	WILSON Station	REID Station	TOTAL All Stations
Current Month O&M Expense for All Plans	-	-	-	-	-	-

Form 3.00

Big Rivers Electric Corporation
Environmental Surcharge Report
Monthly Average Revenue Computation of R(m)

For the Month Ended

Revenues from Member Systems								Total Company Revenues	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Month	**Base Rate Revenues**	**Fuel Clause Revenues**	**Non-FAC PPA Revenues**	**Environmental Surcharge Revenues**	**Total** (2)+(3)+(4)+(5)	**Total Excluding Environmental Surcharge** (6)-(5)	**Off-System Sales**	**Total** (6)+(8)	**Total Excluding Environmental Surcharge** (9)-(5)
Jan									
Feb									
Mar									
Apr									
May									
Jun									
Jul									
Aug									
Sep									
Oct									
Nov									
Dec									
Totals									
Average Monthly Member System Revenues, Excluding Environmental Surcharge, for 12 Months Ending Current Expense Month.									
Member System Allocation Percentage for Current Month (Environmental Surcharge excluded from Calculations): Column (7) / Column (10) =									

Form 3.10

Big Rivers Electric Corporation
Environmental Surcharge Report
Current Month Revenue Computation of R(m) - Detail

For the Month Ended

Class		Revenue						
		Demand	Energy	Base Rates	FAC	Non-FAC PPA	ES	Total
Rural				-				-
Large Industrial				-				-
Subtotal		-	-	-	-	-	-	-

Smelter	Base Fixed Energy (KWH)	Revenue						
		Contractual Premium	Base Monthly Energy	Base Monthly Energy Less Premium	FAC	Non-FAC PPA	ES	Total
Alcan				-				-
Century				-				-
Subtotal		-	-	-	-	-	-	-
Total	[redacted]			-	-	-	-	-

Big Rivers Electric Corporation
2012 Environmental Compliance Plan
Estimated Billing Impact

		Rate ($/MWH)			Increase (%)	
		Base 2012	Base 2016	Build 2016	Relative to 2016	Relative to 2012
Line	Class	1	2	3	(3-2) / 2	(3-2) / 1
1	**Gross of MRSM and RER Rider**					
2						
3	Rural	52.64	58.89	62.98	6.9%	7.8%
4	Large Industrial	45.46	51.64	54.80	6.1%	6.9%
5	Smelter Unadjusted	51.08	54.45	58.18	6.8%	7.3%
6	Smelter Adjusted*	48.13	53.09	55.72	5.0%	5.5%
7						
8	**Net of MRSM and RER Rider: Bill Impact**					
9						
10	Rural	44.32	51.27	51.27	0.0%	0.0%
11	Large Industrial	37.21	51.64	54.80	6.1%	8.5%
12	Smelter Unadjusted	51.08	54.45	58.18	6.8%	7.3%
13	Smelter Adjusted*	48.13	53.09	55.72	5.0%	5.5%

*Smelter Adjusted reflects removal of the TIER Adjustment Charge. The Build Case has lower off-system net sales margin in 2016 due to 2012 Plan costs, causing the Smelters to move up within the TIER bandwidth.

The MRSM and the RER Rider mitigate the costs of ES and FAC to Rurals from Economic Reserve and Rural Economic Reserve in 2016 and beyond.