a PPL company

Hand Delivery

Kentucky Utilities Company
State Regulation and Rates
220 West Main Street
PO Box 32010
Louisville, Kentucky 40232
www.lge-ku.com

Robert M. Conroy
Director - Rates
T 502-627-3324
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robert.conroy@lge-ku.com

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

RECEIVED

JUN 01 2011

PUBLIC SERVICE
COMMISSION

June 1, 2011

RE: *In the Matter of: The Application of Kentucky Utilities Company for Certificates of Public Convenience and Necessity and Approval of Its 2011 Compliance Plan for Recovery by Environmental Surcharge*
Case No. 2011-00161

Dear Mr. DeRouen:

Enclosed please find an original and ten (10) copies of Kentucky Utilities Company's ("KU") Application and Testimonies in the above-referenced docket.

This filing includes:

- KU's Application,
- Statutory Notice,
- Certificate of Notice,
- Lonnie E. Bellar's Testimony,
- John N. Voyles's Testimony and Exhibits,
- Gary H. Revlett's Testimony and Exhibits,
- Charles R. Schram's Testimony and Exhibits,
- Shannon L. Charnas's Testimony, and
- Robert M. Conroy's Testimony and Exhibits.

The original and each copy of KU's application and testimony contains a CD holding an electronic copy of Exhibit GHR-1 through Exhibit GHR-4 and the Appendices to Exhibit JNV-2. These exhibits are provided electronically due to the volume of the material.

Should you have any questions concerning the enclosed, please do not hesitate to contact me. If you receive any requests for copies of the attached document(s), please refer the same to me directly; I will promptly provide such copies upon request.

Sincerely,

Robert M. Conroy

cc: Hon. Dennis G. Howard
Hon. Michael L. Kurtz
Hon. Kendrick R. Riggs
Hon. Allyson K. Sturgeon

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED

JUN 01 2011

PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF KENTUCKY UTILITIES COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	))))))	CASE NO. 2011-00161

APPLICATION

Kentucky Utilities Company ("KU"), pursuant to KRS 278.020(1), KRS 278.183, and 807 KAR 5:001 Sections 8 and 9, hereby petitions the Kentucky Public Service Commission ("Commission") by application to issue an order granting KU Certificates of Public Convenience and Necessity ("CPCN") for the construction of Particulate Matter Control Systems to serve all the generating units at the E.W. Brown Generating Station ("Brown") and the Ghent Generating Station ("Ghent"), and approving an amended compliance plan for purposes of recovering the costs of new pollution control facilities through its Environmental Surcharge tariff ("2011 Environmental Compliance Plan"). These projects are required to comply with the federal Clean Air Act as amended ("CAAA"), the proposed Clean Air Transport Rule ("CATR"), the proposed national emission standards for hazardous air pollutants ("HAPs Rule"), the Resource Conservation and Recovery Act ("RCRA"), and other environmental requirements that apply to KU facilities used in the production of energy from coal, including the U.S. Environmental Protection Agency's ("EPA's") proposed regulation concerning the storage of coal combustion residuals ("CCRs"). In support of this Application, KU states as follows:

1. Address: The Applicant's full name and business address is: Kentucky Utilities Company, One Quality Street, Lexington, Kentucky 40507. KU's mailing address is Kentucky

Utilities Company c/o Louisville Gas and Electric Company, Post Office Box 32010, 220 West Main Street, Louisville, Kentucky 40232.

2. Articles of Incorporation: A certified copy of KU's current Articles of Incorporation are on file with the Commission in Case No. 2010-00204, *In the Matter of: Joint Application of PPL Corporation, E.ON AG, E.ON U.S. Investments Corp., E.ON U.S. LLC, Louisville Gas and Electric Company, and Kentucky Utilities Company for Approval of an Acquisition of Ownership and Control of Utilities*, filed on May 28, 2010, and is incorporated by reference herein pursuant to 807 KAR 5:001, Section 8(3).

3. KU is a public utility, as defined in KRS 278.010(3)(a), engaged in the electric business. KU generates and purchases electricity, and distributes and sells electricity at retail in the following Kentucky counties:

Adair
Anderson
Ballard
Barren
Bath
Bell
Bourbon
Boyle
Bracken
Bullitt
Caldwell
Campbell
Carlisle
Carroll
Casey
Christian
Clark
Clay
Crittenden
Daviess
Edmonson
Estill
Fayette
Fleming
Franklin
Fulton
Gallatin
Garrard
Grant
Grayson
Green
Hardin
Harlan
Harrison
Hart
Henderson
Henry
Hickman
Hopkins
Jessamine
Knox
Larue
Laurel
Lee
Lincoln
Livingston
Lyon
Madison
Marion
Mason
McCracken
McCreary
McLean
Mercer
Montgomery
Muhlenberg
Nelson
Nicholas
Ohio
Oldham
Owen
Pendleton
Pulaski
Robertson
Rockcastle
Rowan
Russell
Scott
Shelby
Spencer
Taylor
Trimble
Union
Washington
Webster
Whitley
Woodford

Request for Certificates of Public Convenience and Necessity

4. KU proposes to build a Particulate Matter Control System to serve each of the three generating units at Brown and the four generating units at Ghent. Each Particulate Matter Control System comprises a pulse-jet fabric filter ("baghouse") to capture particulate matter, a Powdered Activated Carbon ("PAC") injection system to capture mercury, and a lime injection system to protect the baghouse from the corrosive effects of sulfuric acid mist ("SAM"). These Particulate Matter Control Systems will be similar to the baghouse (including the SAM mitigation and PAC injection systems) installed at Trimble County Unit 2 ("TC2") as part of its overall air quality control system (which the Commission approved as part of KU's 2006 Plan).[1]

5. Statement of Need (807 KAR 5:001 § 9(2)(a)): In support of KU's contention that the public convenience and necessity requires the proposed construction of Particulate Matter Control Systems to serve all units at Brown and Ghent, KU states that on March 16, 2011, the EPA proposed the HAPs Rule to regulate certain emissions from coal- and oil-fired electric utility steam generating units. The EPA is under a court order to finalize the HAPs Rule by November 16, 2011. The proposed HAPs Rule standards establish numerical emission limits for many hazardous air pollutants, particularly mercury, based upon the emissions reduction currently achieved by the best-performing 12% of units. Barring an unprecedented intervention by the President of the United States to grant a one-year-compliance extension, KU will have to be in full compliance with the HAPs Rule no later than November 16, 2015 (assuming the final rule is timely issued).

In addition, the lime injection components of the Brown Particulate Matter Control Systems will help to meet the Title V SAM-emissions requirement for Brown that arose from an

[1] 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).

EPA enforcement action. Likewise, the lime injection components of the Ghent Particulate Matter Control Systems will help to respond to certain EPA enforcement actions concerning opacity and Prevention of Significant Deterioration rules concerning Ghent.

Building these Particulate Matter Control Systems is the most cost-effective means of complying with the HAPs Rule, and will help to meet the EPA-imposed SAM-related emissions restrictions at Brown and Ghent.

6. Description of Proposed Construction (807 KAR 5:001 § 9(2)(c)): KU is requesting a CPCN to construct a Particulate Matter Control System at each of the Brown and Ghent units (i.e., KU is requesting a total of seven CPCNs). (Particulate Matter Control Systems are described in Paragraph 4 above.) Each Particulate Matter Control System qualifies as "new" construction that requires prior approval from the Commission under KRS 278.020. The Environmental Air Compliance Strategy Summary for Kentucky Utilities Company and Louisville Gas and Electric Company, attached to the testimony of John N. Voyles as Exhibit JNV-2, contains the engineering work papers related to this construction.

KU proposes to begin installing the Particulate Matter Control Systems at Brown in early 2012, and the work should be complete by the end of 2014 for Units 1 and 2, and mid-2015 for Unit 3. KU proposes to begin installing the Ghent Particulate Matter Control Systems in mid-2012, and the work should be complete by mid-2014 for Unit 1, late 2014 for Unit 2, and late 2015 for Units 3 and 4.

There are no utilities, corporations, or persons with whom the proposed new construction is likely to compete.

7. Permits or Franchises (807 KAR 5:001 § 9(2)(b)): As discussed in the testimony of Gary H. Revlett, KU will submit to the Kentucky Natural Resources and Environmental

Protection Cabinet Division for Air Quality a request to modify existing Title V operating permits to reflect the installation of the proposed Particulate Matter Control Systems at Brown and Ghent. KU will file applications for Title V permit changes by this fall, and will file a copy of the applications with the Commission when they are available. KU will also seek any applicable construction permits.

8. Area Maps (807 KAR 5:001 § 9(2)(d)): The required area maps showing the location where KU proposes to build each of the Particulate Matter Control Systems are attached as Application Exhibit 2.

9. Financing Plans (807 KAR 5:001 § 9(2)(e)): The total projected capital cost of these facilities at Brown is $344 million: $109 million for Unit 1, $118 million for Unit 2, and $117 million for Unit 3.

The total projected capital cost of these facilities at Ghent is $691 million: $157 million for Unit 1, $165 million for Unit 2, $191 million for Unit 3, and $178 million for Unit 4.

KU's proposed financing of such costs is discussed in the prepared direct testimony of Lonnie E. Bellar.

10. Estimated Cost of Operation (807 KAR 5:001 § 9(2)(f)): The estimated annual cost of operations of the proposed construction is shown on page 2 of Exhibit JNV-1 to Mr. Voyles's testimony.

11. The HAPs Rule's tight compliance deadline, the need to arrange construction reasonably around unit outage schedules, and the high industry-wide demand to build similar facilities resulting from the HAPs Rule all necessitate KU's taking quick but carefully analyzed action in response to these new requirements. KU therefore respectfully asks the Commission to issue the requested CPCNs on December 1, 2011, to permit KU to obtain the best pricing

possible under the current market conditions and to attempt to obtain construction contracts that will ensure the maximum timely compliance that is prudently and reasonably feasible.

Request for Approval of KU's 2011 Environmental Compliance Plan for Recovery by Environmental Surcharge

12. This Application and supporting testimony and exhibits are available for public inspection at each KU office where bills are paid. The Company is giving notice to the public of the proposed assessment through its existing environmental surcharge tariff for the recovery of the costs of 2011 Environmental Compliance Plan by newspaper publication and through a bill insert in monthly billings to its customers. The Company is also posting this Application on its website (http://www.lge-ku.com). An initial Certificate of Notice and Publication is filed with this Application. A Certification of Completed Notice and Publication will be filed with the Commission upon the completion of this notice.

13. Pursuant to KRS 278.183, KU is "entitled to the current recovery of its costs of complying with the Federal Clean Air Act as amended and those federal, state, or local environmental requirements which apply to coal combustion wastes and byproducts from facilities utilized for production of energy from coal in accordance with the utility's compliance plan."

14. KU is adding two new projects and amending another. The new projects will enable KU's Brown and Ghent Generating Stations to comply with the Clean Air Act and other current and proposed environmental laws, regulations, and enforcement actions. The amended project will allow the main CCR storage facility at Brown to comply with proposed new regulations under the RCRA and other applicable laws and regulations. The environmental regulations creating the need for these new and additional projects are specifically shown in the

2011 Environmental Compliance Plan, which is attached to this Application (Application Exhibit 1) and to the testimony of Mr. Voyles as Exhibit JNV-1. Mr. Revlett's testimony presents KU's evidence concerning the applicable regulatory requirements, and Mr. Voyles's testimony explains how the pollution control facilities satisfy those regulatory requirements. The pollution control projects included in the 2011 Environmental Compliance Plan are:

a. Amendment to Project 29 (Brown CCR Storage Landfill): Convert the main Brown Ash Pond from wet to dry storage;

b. Project 34 (Brown): Build Particulate Matter Control Systems for all units; add separate SAM mitigation systems to Units 1 and 2 (a separate SAM mitigation system is already being added to Unit 3, which was part of KU's 2009 Plan (Project 28));

c. Project 35 (Ghent): Build Particulate Matter Control Systems for all units; add a separate SAM mitigation system to Unit 2 and modify the existing separate SAM mitigation systems on Units 1, 3, and 4; and modify systems on Units 1, 3, and 4 to expand the generating-unit-operating range at which the selective catalytic reduction ("SCR") systems on those units can operate efficiently.

The total capital cost of these new projects to the Compliance Plan is estimated to be $1.1 billion.

As described in Robert M. Conroy's testimony, KU proposes to report the SAM-sorbent-O&M costs of Brown Unit 3's separate SAM mitigation system (when it goes into service) as part of Project 34's SAM-sorbent-O&M costs. Similarly, KU proposes to report the SAM-sorbent-O&M costs of Ghent Units 1, 3, and 4's existing SAM mitigation systems as part of Project 35's SAM-sorbent-O&M costs.

15. A detailed summary of the facts and compliance requirements supporting this Application is set forth in the direct testimony and exhibits of the Company's witnesses:

- The testimony of Lonnie E. Bellar, Vice President, State Regulation and Rates, presents an overview of KU's environmental surcharge plan and supporting testimony, and requests the recovery of an overall rate of return that includes a 10.63% return on common equity. His testimony also states the reasons KU is seeking CPCNs for certain ECR projects, the reasons for requesting the projects themselves, and how KU plans to finance the projects.
- John N. Voyles, Vice President, Transmission and Generation Services, presents testimony that describes the engineering and construction aspects of the projects in KU's 2011 Plan, and the operations and maintenance costs and savings for the projects. Mr. Voyles sponsors the 2011 Plan and the Environmental Air Compliance Strategy Summary for Kentucky Utilities Company and Louisville Gas and Electric Company.
- Gary H. Revlett, Director, Environmental Affairs, presents testimony discussing the environmental regulations that necessitate KU's 2011 Plan. Mr. Revlett describes the pertinent statutes, rules, or regulations requiring KU to take action.
- Charles R. Schram, Director, Energy Planning, Analysis and Forecasting, presents testimony on the cost-effectiveness of the projects in KU's 2011 Plan, and presents as exhibits the cost-benefit studies KU performed.

- Shannon L. Charnas, Director, Accounting and Regulatory Reporting, presents testimony affirming that the costs for which KU is seeking recovery through its Environmental Surcharge tariff are not included in base rates, and describes the accounting associated with the projects in KU's 2011 Plan, all consistent with the Commission's prior orders.
- Robert M. Conroy, Director, Rates, presents KU's proposed Electric Rate Schedule ECR and corresponding monthly reporting requirements, and presents testimony affirming that the calculation of KU's environmental surcharge will comply with all previous Commission Orders. Mr. Conroy also presents the revisions to the monthly ECR reporting forms that KU proposes, and explains why the revisions to the forms are appropriate. In addition, Mr. Conroy discusses the bill impact on KU's customers.

16. KU is proposing some minor clarifying changes to its Environmental Cost Recovery Surcharge tariff, P.S.C. No. 15, Original Sheet No. 87, *Adjustment Clause ECR*, but no substantive changes to the terms or conditions thereof. KU is filing its Environmental Cost Recovery Surcharge tariff, attached as Application Exhibit 3, for the purpose of obtaining the Commission's approval of the recovery of the costs of 2011 Environmental Compliance Plan by the proposed assessment through this tariff. In accordance with KRS 278.183(2), the ECR tariff has an issue date of June 1, 2011, and is proposed to be effective on December 1, 2011. Therefore, bills issued on and after January 31, 2012, will reflect the revised environmental surcharge beginning with the expense month of December 2011 (i.e., beginning with the expense month six months after the filing of this Application).

WHEREFORE, Kentucky Utilities Company respectfully asks the Commission to enter an order on December 1, 2011: (1) granting KU Certificates of Public Convenience and Necessity to permit the construction of Particulate Matter Control Systems to serve all Brown and Ghent units; (2) approving the new and amended projects to KU's Compliance Plan for purposes of recovering the costs of the projects through the environmental surcharge mechanism; (3) approving the proposed environmental surcharge tariff for the recovery of the costs of 2011 Environmental Compliance Plan effective for bills rendered on and after January 31, 2012 (i.e., beginning with the expense month of December 2011); (4) approving the proposed ES monthly filing forms; (5) approving the recovery of the overall rate of return requested herein, including the return on equity therein; and (6) granting such other relief as KU may be entitled under law.

Dated: June 1, 2011

Respectfully submitted,

Allyson K Sturgeon

Kendrick R. Riggs
W. Duncan Crosby III
Stoll Keenon Ogden PLLC
2000 PNC Plaza
500 West Jefferson Street
Louisville, Kentucky 40202
Telephone: (502) 333-6000

Allyson K. Sturgeon
Senior Corporate Attorney
LG&E and KU Services Company
220 West Main Street
Louisville, Kentucky 40202
Telephone: (502) 627-2088

Counsel for Kentucky Utilities Company

CERTIFICATE OF SERVICE

The undersigned hereby certifies that a true and correct copy of the foregoing Application was served on the following persons on the 1st day of June 2011, U.S. mail, postage prepaid:

Dennis G. Howard II
Lawrence W. Cook
Assistant Attorneys General
Office of the Attorney General
Office of Rate Intervention
1024 Capital Center Drive, Suite 200
Frankfort, KY 40601-8204

Michael L. Kurtz
Boehm, Kurtz & Lowry
36 East Seventh Street, Suite 1510
Cincinnati, OH 45202

Allyson K. Sturgeon
Counsel for Kentucky Utilities Company

Statutory Notice

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF KENTUCKY UTILITIES COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	))))))	**CASE NO. 2011-00161**

STATUTORY NOTICE

Kentucky Utilities Company ("KU"), by counsel, informs the Kentucky Public Service Commission ("Commission") that it is engaged in business as an operating public utility, principally furnishing retail electric service within 77 counties throughout the Commonwealth of Kentucky.

Pursuant to KRS 278.183, and as required, KRS 278,020(1), KU hereby gives notice to the Commission that, on this 1st day of June 2011, it files herewith its application to issue an order granting KU Certificates of Public Convenience and Necessity for the construction of baghouses with powdered activated carbon injection and lime injection systems at all Brown and Ghent Units, and approving an amended compliance plan for purposes of recovering the costs of new pollution control facilities through its Rate Schedule ECR.

Notice is further given that KU proposes to adjust its Rate Schedule ECR effective December 1, 2011, for purposes of recovering the costs of 2011 Environmental Compliance Plan by an increased assessment to customers' bills beginning on January 31, 2012 in conformity with the attached schedule.

Submitted to the Commission this 1st day of June 2011.

Respectfully submitted,

Allyson K. Sturgeon

Kendrick R. Riggs
W. Duncan Crosby III
Stoll Keenon Ogden PLLC
2000 PNC Plaza
500 West Jefferson Street
Louisville, Kentucky 40202
Telephone: (502) 333-6000

Allyson K. Sturgeon
Senior Corporate Attorney
LG&E and KU Services Company
220 West Main Street
Louisville, Kentucky 40202
Telephone: (502) 627-2088

Counsel for Kentucky Utilities Company

CERTIFICATE OF SERVICE

The undersigned hereby certifies that the original and ten copies of the foregoing Statutory Notice was filed with the Kentucky Public Service Commission and a true and correct copy of the same was served on the following persons on the 1st day of June 2011, U.S. mail, postage prepaid:

Dennis G. Howard II
Lawrence W. Cook
Assistant Attorneys General
Office of the Attorney General
Office of Rate Intervention
1024 Capital Center Drive, Suite 200
Frankfort, KY 40601-8204

Michael L. Kurtz
Boehm, Kurtz & Lowry
36 East Seventh Street, Suite 1510
Cincinnati, OH 45202

Counsel for Kentucky Utilities Company

Adjustment Clause **ECR**

Environmental Cost Recovery Surcharge

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This schedule is mandatory to all Standard Electric Rate Schedules listed in Section 1 of the General Index except CTAC and Special Charges, all Pilot Programs listed in Section 3 of the General Index, and the FAC and DSM Adjustment Clauses. T T T

RATE

The monthly billing amount under each of the schedules to which this mechanism is applicable, including the fuel clause and demand-side management cost recovery mechanisms, shall be increased or decreased by a percentage factor calculated in accordance with the following formula. T

Jurisdictional Environmental Surcharge Billing Factor = E(m) / R(m) T

As set forth below, E(m) is the jurisdictional total of each approved environmental compliance plan revenue requirement of environmental compliance costs for the current expense month and R(m) is the revenue for the current expense month. T T

DEFINITIONS

1) For all Plans, E(m) = [(RB/12) (ROR + (ROR – DR) (TR / (1 – TR))] + OE – BAS + BR
   a) RB is the Total Environmental Compliance Rate Base.
   b) ROR is the Rate of Return on Environmental Compliance Rate Base, designated as the overall rate of return [cost of short-term debt, long-term debt, preferred stock, and common equity].
   c) DR is the Debt Rate [cost of short-term debt, and long-term debt].
   d) TR is the Composite Federal and State Income Tax Rate.
   e) OE is the Operating Expenses [Depreciation and Amortization Expense, Property Taxes, Emission Allowance Expense and O&M expense adjusted for the Average Month Expense already included in existing rates]. Includes operation and maintenance expense recovery authorized by the K.P.S.C. in all approved ECR Plan proceedings. T
   f) BAS is the total proceeds from by-product and allowance sales.
   g) BR is the operation and maintenance expenses, and/or revenues if applicable, associated with Beneficial Reuse.
   h) Plans are the environmental surcharge compliance plans submitted to and approved by the Kentucky Public Service Commission pursuant to KRS 278.183. T T
2) Total E(m) (sum of each approved environmental compliance plan revenue requirement) is multiplied by the Jurisdictional Allocation Factor and reduced by current expense month ECR revenue collected through base rates to arrive at the Net Jurisdictional E(m).
3) The revenue R(m) is the average monthly base revenue for the Company for the 12 months ending with the current expense month. Base revenue includes the customer, energy and demand charge for each rate schedule to which this mechanism is applicable and automatic adjustment clause revenues for the Fuel Adjustment Clause and the Demand-Side Management Cost Recovery Mechanism as applicable for each rate schedule.
4) Current expense month (m) shall be the second month preceding the month in which the Environmental Surcharge is billed.

Certificate of Notice

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF KENTUCKY UTILITIES COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	))))))	**CASE NO. 2011-00161**

CERTIFICATE OF NOTICE AND PUBLICATION

Pursuant to the Kentucky Public Service Commission's Rules Governing Tariffs effective August 4, 1984, I hereby certify that I am Lonnie E. Bellar, Vice President, State Regulation and Rates, for Kentucky Utilities Company ("KU" or "Company"), a utility furnishing retail electric service within the Commonwealth of Kentucky, which, on the 1st day of June 2011, will file an application to issue an order granting KU Certificates of Public Convenience and Necessity for the construction of baghouses with powdered activated carbon injection and lime injection systems at all Brown and Ghent Units, and approving an amended compliance plan for purposes of recovering the costs of new pollution control facilities through its Rate Schedule ECR as required by KRS 278.183, and as applicable KRS 278,020(1).

In connection with its application, on the first day of June, 2011, KU will issue and file its proposed Rate Schedule ECR, P.S.C. No. 15, First Revision of Original Sheet No. 87, effective December 1, 2011, for purposes of recovering the costs of 2011 Environmental Compliance Plan by an increased assessment to customers' bills beginning on January 31, 2012, and that notice to the public of the issuing of the same is being given as follows:

On the 1st day of June 2011, the same will be delivered for exhibition and public inspection at the offices and places of business of the Company in the territory affected thereby, to-wit, at the following places:

Barlow	London
Campbellsville	Maysville
Carrollton	Middlesboro
Danville	Morehead
Earlington	Morganfield
Eddyville	Mt. Sterling
Elizabethtown	Paris
Georgetown	Richmond
Greenville	Shelbyville
Harlan	Somerset
Lexington	Versailles
	Winchester

and that the same will be kept open to public inspection at said offices and places of business in conformity with the requirements of 807 KAR 5:011, Section 8.

I further certify that more than twenty (20) customers will be affected by said change by way of an increase in their bills, and that on the 13th day of May 2011, there was delivered to the Kentucky Press Association, an agency that acts on behalf of newspapers of general circulation throughout the Commonwealth of Kentucky in which customers affected reside, for publication therein once a week for three consecutive weeks beginning the week of May 25, 2011, a notice of the filing of KU's application, a copy of said notice being attached hereto as Appendix A. A certificate of publication of said notice will be furnished to the Kentucky Public Service Commission upon completion of same pursuant to 807 KAR 5:011, Sections 8 and 15.

In addition, Kentucky Utilities Company will include a general statement explaining the application in this case with the bills for its Kentucky retail customers during the course of the Company's regular monthly billing cycle beginning on May 31, 2011, a copy of said notice being attached hereto as Appendix B.

A copy of the application will also be posted on Kentucky Utilities Company's website (http://www.lge-ku.com) beginning on June 1, 2011.

Given under my hand this 31st day of May 2011.

Lonnie E. Bellar
Vice President, State Regulation and Rates
Kentucky Utilities Company
220 West Main Street
Louisville, Kentucky 40202

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 31st day of May 2011.

Kimberly M Walker (SEAL)
Notary Public

My Commission Expires:
9/11/2012

APPENDIX A

NOTICE TO CUSTOMERS OF
KENTUCKY UTILITIES COMPANY

RECOVERY BY ENVIRONMENTAL SURCHARGE OF KENTUCKY UTILITIES COMPANY'S 2011 ENVIRONMENTAL COMPLIANCE PLAN

PLEASE TAKE NOTICE that on June 1, 2011, Kentucky Utilities Company ("KU") will file with the Kentucky Public Service Commission ("Commission") in Case No. 2011-00161, an Application pursuant to Kentucky Revised Statute 278.183 for approval of an amended compliance plan ("KU's 2011 Environmental Compliance Plan") for the purpose of recovering the capital costs and operation and maintenance costs associated with new pollution control facilities through an increase in the environmental surcharge on customers' bills beginning January 31, 2012 under KU's existing Electric Rate Schedule ECR, also known as the environmental cost recovery surcharge.

Federal, state, and local environmental regulations require KU to build and upgrade equipment and facilities to operate in an environmentally sound manner. Specifically, KU is seeking Commission approval of Certificates of Public Convenience and Necessity ("CPCN") to construct new Particulate Matter Control Systems to serve all units at the Ghent Generating Station in Ghent, Kentucky, and to serve all units at the E.W. Brown Generating Station in Burgin, Kentucky, to comply with the national emissions standards for hazardous air pollutants proposed by the U.S. Environmental Protection Agency ("EPA"). The Particulate Matter Control Systems are also being installed to comply with EPA-imposed sulfuric acid mist and opacity requirements. Additionally, KU is seeking recovery of costs associated with these environmental projects, which are necessary for compliance with the federal Clean Air Act, the federal Resource Conservation and Recovery Act, and other current or proposed environmental laws and regulations, and enforcement actions. These additional projects primarily relate to installing Particulate Matter Control Systems to serve all units at the Ghent Generating Station, installing Particulate Matter Control Systems to serve all units at the E.W. Brown Generating Station, converting the main coal combustion residuals treatment basin at the E.W. Brown Generating Station to a landfill and other pollution control facilities. The capital cost of the new pollution control facilities for which KU is seeking recovery at this time is estimated to be $1.1 billion. Additional operation and maintenance expenses will be incurred for these projects and are costs that KU is requesting to recover through the environmental surcharge in its application.

The impact on KU's customers is estimated to be a 1.5% increase in 2012 with a maximum increase of 12.2% in 2016. For a KU residential customer using 1,000 kilowatt hours per month, the initial monthly increase is expected to be $1.13 during 2012, with the maximum monthly increase expected to be $9.46 during 2016.

The Environmental Surcharge Application described in this Notice is proposed by KU. However, the Public Service Commission may issue an order modifying or denying KU's Environmental Surcharge Application. Such action may result in an environmental surcharge for consumers other than the environmental surcharge described in this Notice.

Any corporation, association, body politic or person may, by motion within thirty (30) days after publication, request leave to intervene in Case No. 2011-00161. That motion shall be submitted to the Public Service Commission, 211 Sower Blvd., P.O. Box

615, Frankfort, Kentucky, 40602, and shall set forth the grounds for the request including the status and interest of the party. Intervenors may obtain copies of the Application and testimony by contacting Kentucky Utilities Company at 220 West Main Street, Louisville, Kentucky, 40202, Attention: Lonnie E. Bellar, Vice President, State Regulation and Rates. A copy of the Application and testimony will be available for public inspection on KU's website (http://www.lge-ku.com) and at KU's offices where bills are paid after June 1, 2011.

APPENDIX B

Dear KU Customer:

To comply with existing and new federal environmental laws and regulations, KU must continue to invest in additional pollution control facilities. Currently, KU is seeking Kentucky Public Service Commission ("KPSC") approval to build additional pollution control facilities. Following KPSC approval, the actual costs associated with the pollution control facilities would be passed on to retail customers through the existing Environmental Surcharge billing factor. KU estimates that the initial impact would be an increase in the environmental surcharge of $1.13 per month for a residential customer using 1,000 kilowatt hours (kWh) per month. The announcement below is included to comply with KPSC regulations regarding notice of tariff changes to customers. If approved as filed, this change in rates will be included on customer bills no sooner than January 31, 2012.

NOTICE TO CUSTOMERS OF
KENTUCKY UTILITIES COMPANY

RECOVERY BY ENVIRONMENTAL SURCHARGE OF KENTUCKY UTILITIES COMPANY'S 2011 ENVIRONMENTAL COMPLIANCE PLAN

PLEASE TAKE NOTICE that on June 1, 2011, Kentucky Utilities Company ("KU") will file with the Kentucky Public Service Commission ("Commission") in Case No. 2011-00161, an Application pursuant to Kentucky Revised Statute 278.183 for approval of an amended compliance plan ("KU's 2011 Environmental Compliance Plan") for the purpose of recovering the capital costs and operation and maintenance costs associated with new pollution control facilities through an increase in the environmental surcharge on customers' bills beginning January 31, 2012 under KU's existing Electric Rate Schedule ECR, also known as the environmental cost recovery surcharge.

Federal, state, and local environmental regulations require KU to build and upgrade equipment and facilities to operate in an environmentally sound manner. Specifically, KU is seeking Commission approval of Certificates of Public Convenience and Necessity ("CPCN") to construct new Particulate Matter Control Systems to serve all units at the Ghent Generating Station in Ghent, Kentucky, and to serve all units at the E.W. Brown Generating Station in Burgin, Kentucky, to comply with the national emissions standards for hazardous air pollutants proposed by the U.S. Environmental Protection Agency ("EPA"). The Particulate Matter Control Systems are also being installed to comply with EPA-imposed sulfuric acid mist and opacity requirements. Additionally, KU is seeking recovery of costs associated with these environmental projects, which are necessary for compliance with the federal Clean Air Act, the federal Resource Conservation and Recovery Act, and other current or proposed environmental laws and regulations, and enforcement actions. These additional projects primarily relate to installing Particulate Matter Control Systems to serve all units at the Ghent Generating Station, installing Particulate Matter Control Systems to serve all units at the E.W. Brown Generating Station, converting the main coal combustion residuals treatment basin at the E.W. Brown Generating Station to a landfill and other pollution control facilities. The capital cost of the new pollution control facilities for which KU is seeking recovery at this time is estimated to be $1.1 billion. Additional operation and maintenance expenses will be incurred for these projects and are costs that KU is requesting to recover through the environmental surcharge in its application.

The impact on KU's customers is estimated to be a 1.5% increase in 2012 with a maximum increase of 12.2% in 2016. For a KU residential customer using 1,000 kilowatt hours per month, the initial monthly increase is expected to be $1.13 during 2012, with the maximum monthly increase expected to be $9.46 during 2016.

The Environmental Surcharge Application described in this Notice is proposed by KU. However, the Public Service Commission may issue an order modifying or denying KU's Environmental Surcharge Application. Such action may result in an environmental surcharge for consumers other than the environmental surcharge described in this Notice.

Any corporation, association, body politic or person may, by motion within thirty (30) days after publication, request leave to intervene in Case No. 2011-00161. That motion shall be submitted to the Public Service Commission, 211 Sower Blvd., P.O. Box 615, Frankfort, Kentucky, 40602, and shall set forth the grounds for the request including the status and interest of the party. Intervenors may obtain copies of the Application and testimony by contacting Kentucky Utilities Company at 220 West Main Street, Louisville, Kentucky, 40202, Attention: Lonnie E. Bellar, Vice President, State Regulation and Rates. A copy of the Application and testimony will be available for public inspection on KU's website (http://www.lge-ku.com) and at KU's offices where bills are paid after June 1, 2011.

Exhibit 1-2011 Plan

KENTUCKY UTILITIES COMPANY
2011 ENVIRONMENTAL COMPLIANCE PLAN

Project	Air Pollutant or Waste/By-Product To Be Controlled	Control Facility	Generating Station	Environmental Regulation / Regulatory Requirement*	Environmental Permit*	Actual or Scheduled Completion	Actual (A) or Estimated (E) Projected Capital Cost ($Million)
29 Amended	Fly & Bottom Ash, Gypsum	Coal Combustion Residual Storage Landfill (conversion from wet to dry storage)	Brown Station	EPA CCR Regulations	Division of Waste Mgmt - Landfill Permit	2014	$58.67 (E)
34	NO_x, SO_3, Hg and Particulate	Baghouse with Powdered Activated Carbon Injection (shared Units 1 & 2, Unit 3); Sulfuric Acid Mist Mitigation (Units 1 and 2)	Brown Unit 1	Clean Air Act (1990), PSD Rules, EPA Consent Decree, and HAPS	Title V Permit	2014	$109.22 (E)
			Brown Unit 2			2014	$117.65 (E)
			Brown Unit 3			2015	$116.92 (E)
35	NO_x, SO_3, Hg and Particulate	Baghouse with Powdered Activated Carbon Injection (All Units), SCR Turn-Down (Unit 1, 3, 4), Sulfuric Acid Mist Mitigation (All Units)	Ghent Unit 1	Clean Air Act (1990), HAPS, CATR, KRS Chapter 224, PSD Rules	Title V Permit	2014	$164.21 (E)
			Ghent Unit 2			2012-2014	$164.55 (E)
			Ghent Unit 3			2013-2015	$198.01 (E)
			Ghent Unit 4			2014-2015	$184.76 (E)
							$1,113.99

* Sponsored by Witness Revlett

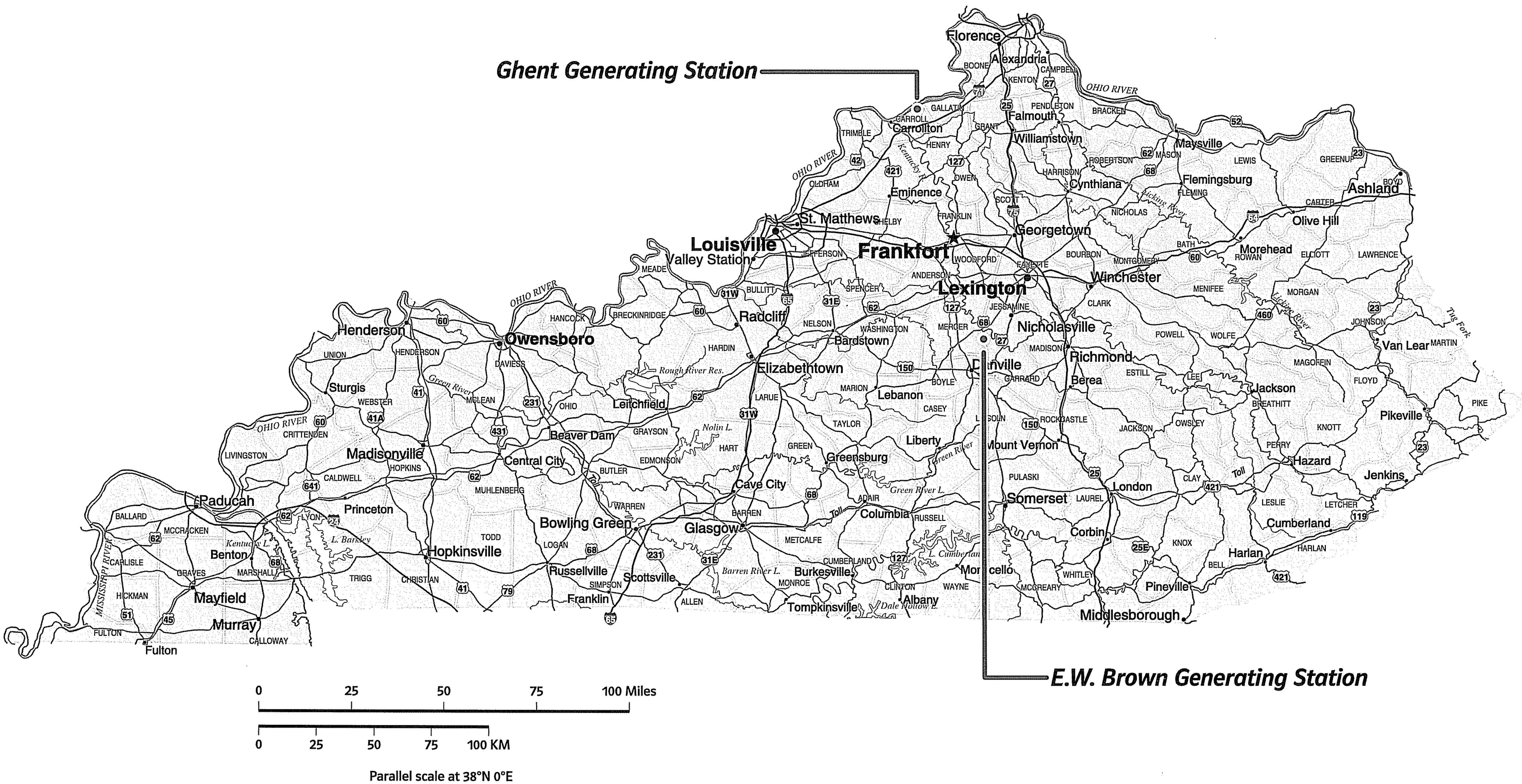
KENTUCKY UTILITIES COMPANY

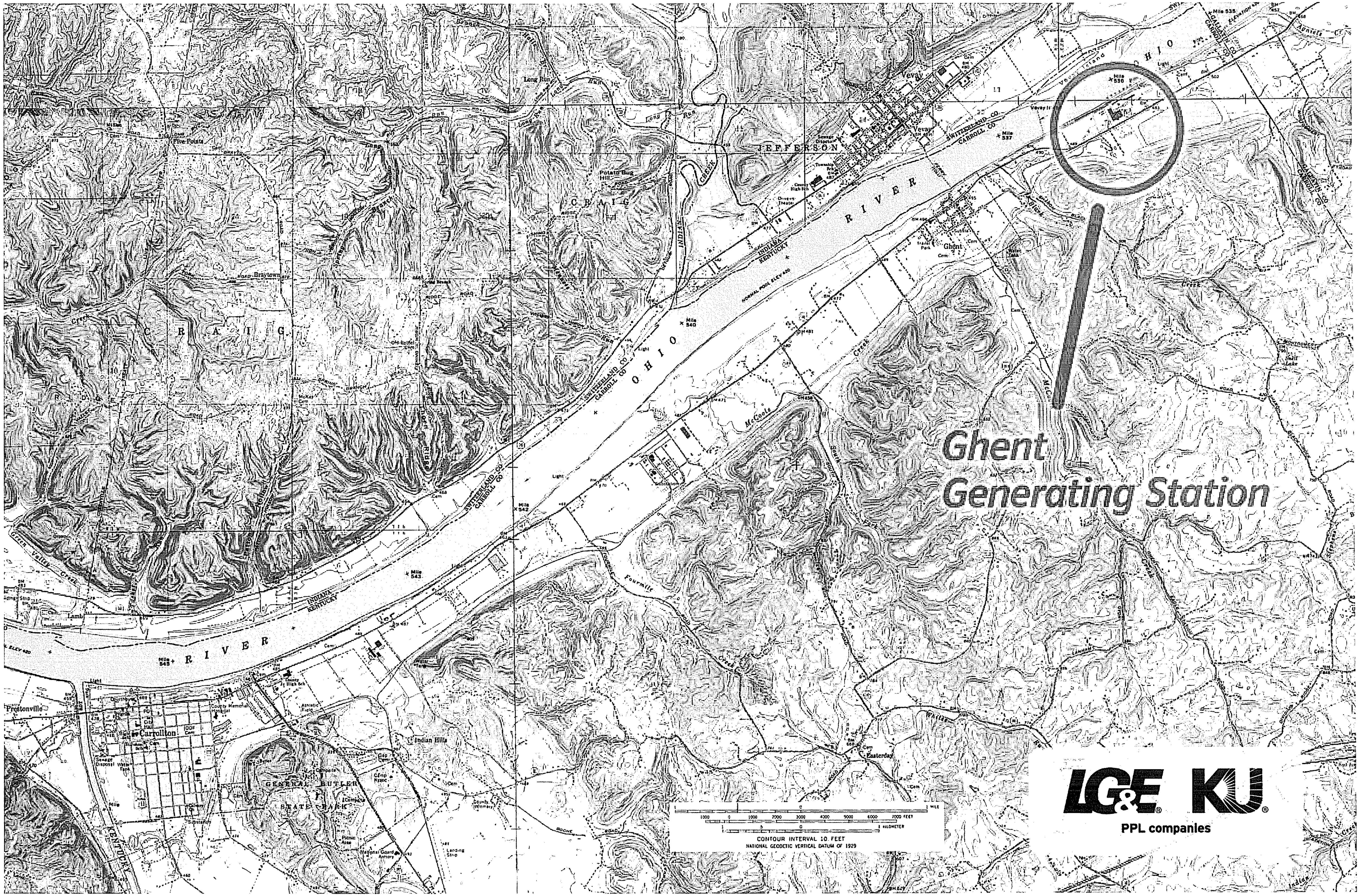
2011 ENVIRONMENTAL COMPLIANCE PLAN

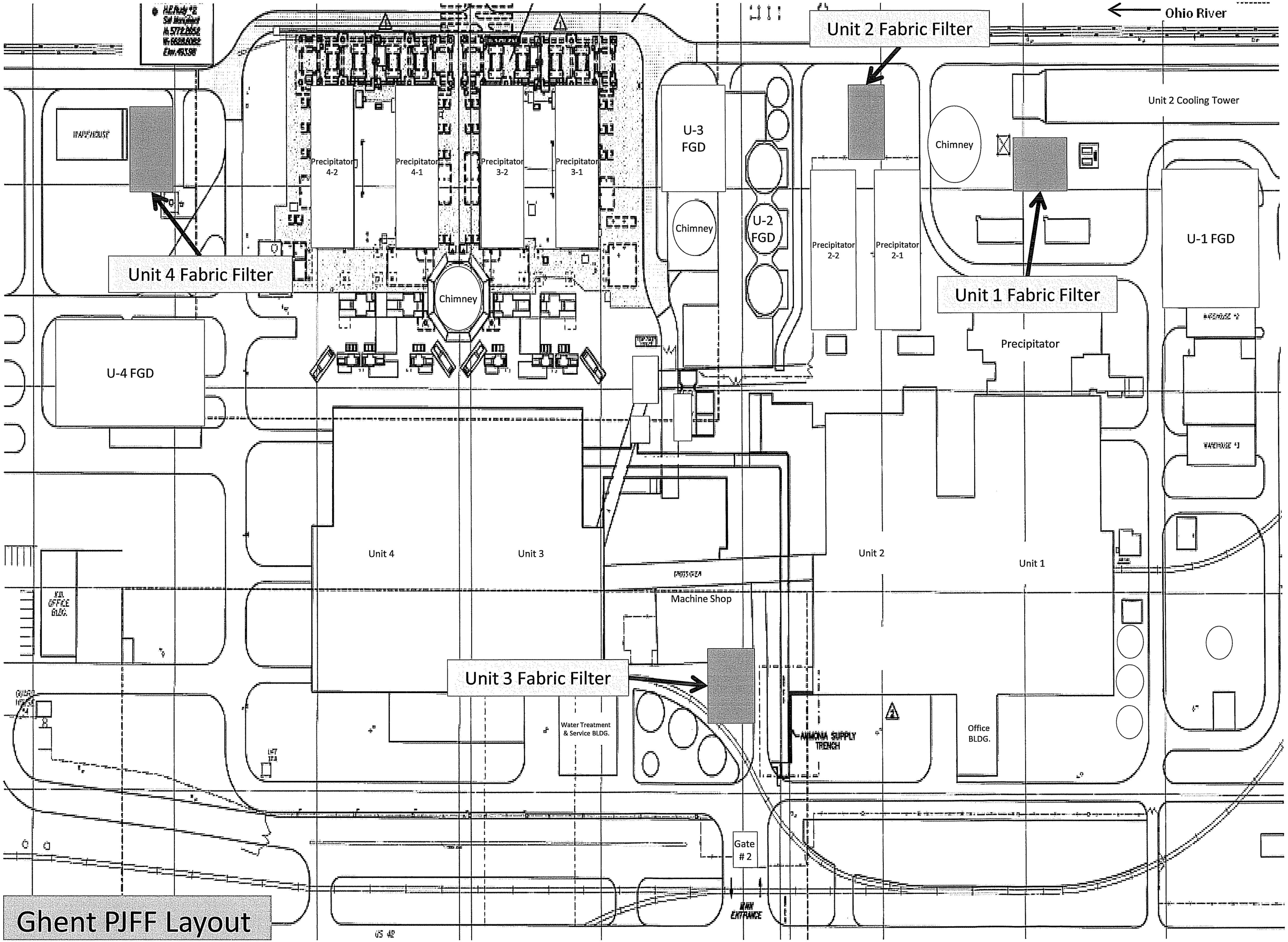
Project	Air Pollutant or Waste/By-Product To Be Controlled	Control Facility	Generating Station	Estimated Annual Operations and Maintenance Costs (Through 2020)								
				2012	2013	2014	2015	2016	2017	2018	2019	2020
29 Amended	Fly & Bottom Ash, Gypsum	Coal Combustion Residual Storage Landfill (conversion from wet to dry storage)	Brown Station	$ -	$ -	$ 2,813,772	$ 2,898,185	$ 2,985,131	$ 3,074,685	$ 3,166,925	$ 3,261,933	$ 3,359,791
34	NO_x, SO_3, Hg and Particulate	Baghouse with Powdered Activated Carbon Injection (shared Units 1 & 2, Unit 3); Sulfuric Acid Mist Mitigation (Units 1 and 2)	Brown Unit 1	$ -	$ -	$ 2,483,343	$ 4,809,135	$ 4,905,317	$ 5,003,424	$ 5,103,492	$ 5,205,562	$ 5,309,673
			Brown Unit 2	$ -	$ -	$ 5,052,836	$ 6,871,856	$ 7,009,293	$ 7,149,479	$ 7,292,469	$ 7,438,318	$ 7,587,085
			Brown Unit 3	$ -	$ -	$ -	$ 4,687,119	$ 7,171,292	$ 7,314,718	$ 7,461,012	$ 7,610,232	$ 7,762,437
35	NO_x, SO_3, Hg and Particulate	Baghouse with Powdered Activated Carbon Injection (All Units), SCR Turn-Down (Unit 1, 3, 4), Sulfuric Acid Mist Mitigation (All Units)	Ghent Unit 1	$ -	$ 2,730,914	$ 12,899,794	$ 17,179,567	$ 17,523,158	$ 17,873,621	$ 18,231,093	$ 18,595,715	$ 18,967,630
			Ghent Unit 2	$ 8,692	$ 1,276,696	$ 2,183,254	$ 12,112,005	$ 12,354,245	$ 12,601,330	$ 12,853,356	$ 13,110,424	$ 13,372,632
			Ghent Unit 3	$ -	$ 642,953	$ 4,721,847	$ 6,363,418	$ 17,537,222	$ 17,887,966	$ 18,245,725	$ 18,610,640	$ 18,982,853
			Ghent Unit 4	$ -	$ 3,578,918	$ 5,256,715	$ 5,848,876	$ 17,391,503	$ 17,739,333	$ 18,094,120	$ 18,456,002	$ 18,825,122

Exhibit 2-Maps

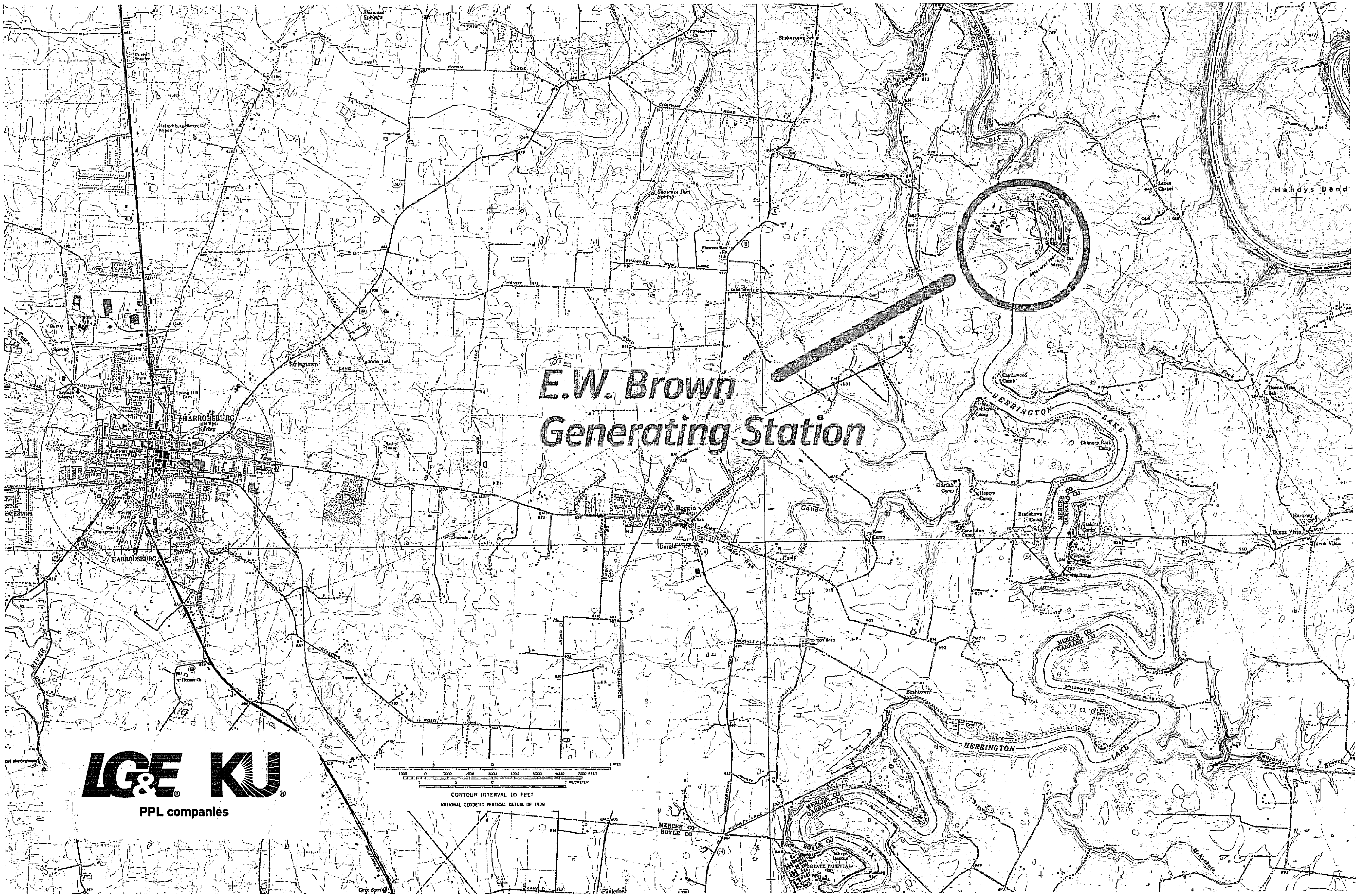
PPL companies

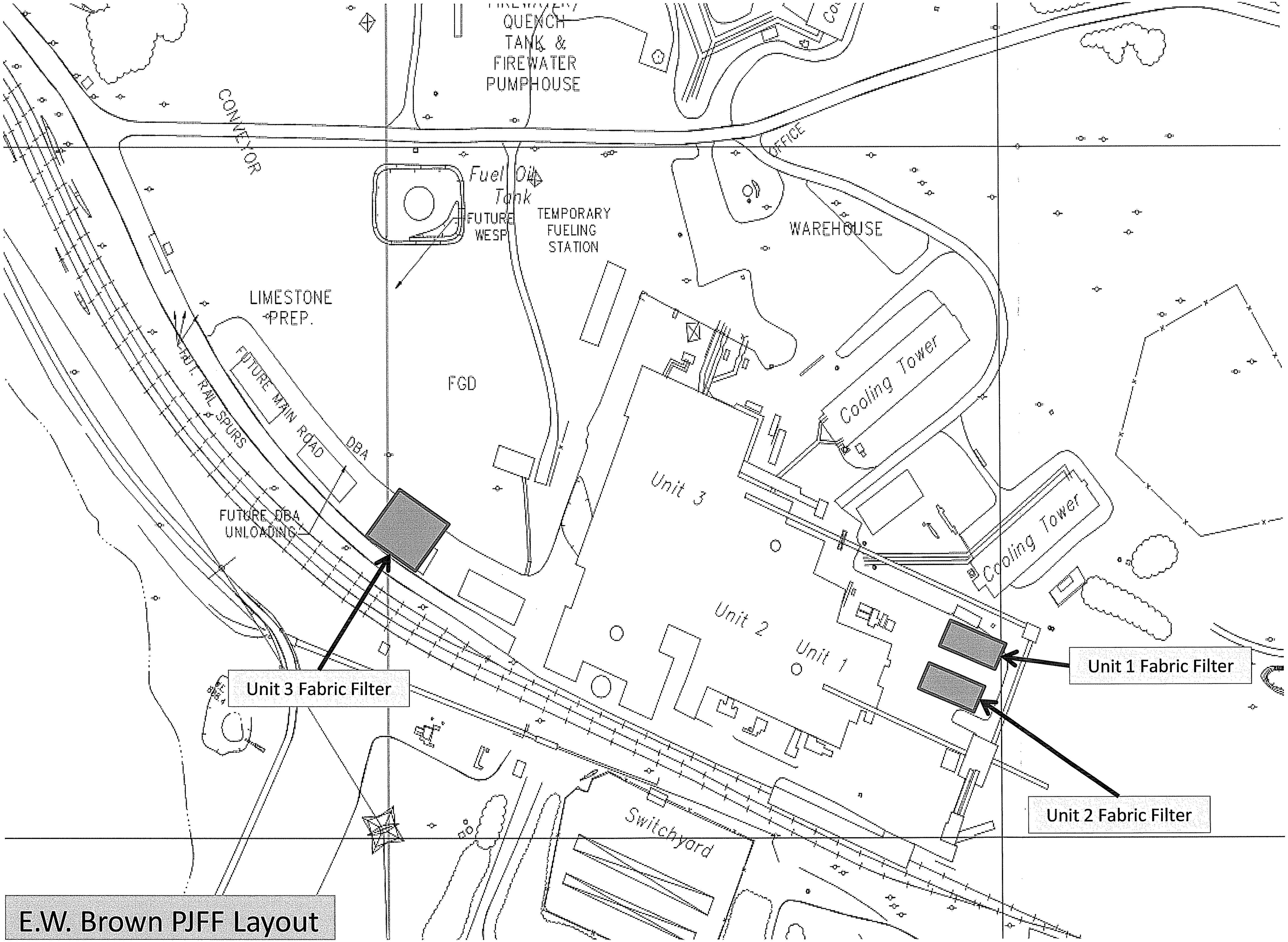



Ghent Generating Station
OHIO RIVER
JEFFERSON
CRAIG
Vevay
Ghent
Carrollton
Prestonville
Indian Hills
GENERAL BUTLER STATE PARK
SWITZERLAND CO.
CARROLL CO.
INDIANA
KENTUCKY
CONTOUR INTERVAL 10 FEET
NATIONAL GEODETIC VERTICAL DATUM OF 1929
LG&E KU
PPL companies



Ghent PJFF Layout


E.W. Brown
Generating Station
HARRODSBURG
Burgin
HERRINGTON LAKE
Handys Bend
Stringtown
Bushtown
MERCER CO
BOYLE CO
CONTOUR INTERVAL 10 FEET
NATIONAL GEODETIC VERTICAL DATUM OF 1929
LG&E KU
PPL companies



E.W. Brown PJFF Layout

Exhibit 3-Tariff

Adjustment Clause **ECR**

Environmental Cost Recovery Surcharge

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This schedule is mandatory to all Standard Electric Rate Schedules listed in Section 1 of the General Index except CTAC and Special Charges, all Pilot Programs listed in Section 3 of the General Index, and the FAC and DSM Adjustment Clauses. T T T

RATE

The monthly billing amount under each of the schedules to which this mechanism is applicable, including the fuel clause and demand-side management cost recovery mechanisms, shall be increased or decreased by a percentage factor calculated in accordance with the following formula. T

Jurisdictional Environmental Surcharge Billing Factor = E(m) / R(m) T

As set forth below, E(m) is the jurisdictional total of each approved environmental compliance plan revenue requirement of environmental compliance costs for the current expense month and R(m) is the revenue for the current expense month. T T

DEFINITIONS

1) For all Plans, E(m) = [(RB/12) (ROR + (ROR – DR) (TR / (1 – TR))] + OE – BAS + BR
   a) RB is the Total Environmental Compliance Rate Base.
   b) ROR is the Rate of Return on Environmental Compliance Rate Base, designated as the overall rate of return [cost of short-term debt, long-term debt, preferred stock, and common equity].
   c) DR is the Debt Rate [cost of short-term debt, and long-term debt].
   d) TR is the Composite Federal and State Income Tax Rate.
   e) OE is the Operating Expenses [Depreciation and Amortization Expense, Property Taxes, Emission Allowance Expense and O&M expense adjusted for the Average Month Expense already included in existing rates]. Includes operation and maintenance expense recovery authorized by the K.P.S.C. in all approved ECR Plan proceedings. T
   f) BAS is the total proceeds from by-product and allowance sales.
   g) BR is the operation and maintenance expenses, and/or revenues if applicable, associated with Beneficial Reuse.
   h) Plans are the environmental surcharge compliance plans submitted to and approved by the Kentucky Public Service Commission pursuant to KRS 278.183. T T

2) Total E(m) (sum of each approved environmental compliance plan revenue requirement) is multiplied by the Jurisdictional Allocation Factor and reduced by current expense month ECR revenue collected through base rates to arrive at the Net Jurisdictional E(m).

3) The revenue R(m) is the average monthly base revenue for the Company for the 12 months ending with the current expense month. Base revenue includes the customer, energy and demand charge for each rate schedule to which this mechanism is applicable and automatic adjustment clause revenues for the Fuel Adjustment Clause and the Demand-Side Management Cost Recovery Mechanism as applicable for each rate schedule.

4) Current expense month (m) shall be the second month preceding the month in which the Environmental Surcharge is billed.

Testimony

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF KENTUCKY UTILITIES COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	))))))	CASE NO. 2011-00161

DIRECT TESTIMONY OF LONNIE E. BELLAR VICE PRESIDENT, STATE REGULATION AND RATES KENTUCKY UTILITIES COMPANY

Filed: June 1, 2011

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

A. My name is Lonnie E. Bellar. I am the Vice President, State Regulation and Rates for Kentucky Utilities Company ("KU"). I am employed by LG&E and KU Services Company, which provides services to Louisville Gas and Electric Company ("LG&E") and KU (collectively "the Companies"). My business address is 220 West Main Street, Louisville, Kentucky, 40202. A complete statement of my education and work experience is attached to this testimony as Appendix A.

Q. Have you previously testified before this Commission?

A. Yes. I have previously testified before this Commission in numerous proceedings, including the Companies' most recent base rate cases (Case Nos. 2009-00548 (KU) and 2009-00549 (LG&E)) and environmental cost recovery compliance plan proceedings (Case Nos. 2009-00197 (KU) and 2009-00198 (LG&E)).

Q. What is the purpose of your testimony?

A. My testimony provides an overview of our other witnesses' testimony, KU's 2011 Environmental Compliance Plan ("2011 Plan"), our request for Certificates of Public Convenience and Necessity ("CPCNs") for facilities contained in the 2011 Plan, and an amendment to KU Project 29 which was approved as part of KU's 2009 Plan.[1] I will also explain why KU is seeking environmental surcharge recovery of its 2011 Plan through the Environmental Cost Recovery ("ECR") Surcharge tariff for bills rendered on and after January 31, 2012 (i.e., beginning with the expense month December 2011), which will use the 10.63 percent return on common equity agreed to in KU's last rate case. I will also address the plan to finance the proposed

[1] *In the Matter of: The Application of Kentucky Utilities Company for Certificates of Public Convenience and Necessity and Approval of Its 2009 Compliance Plan for Recovery by Environmental Surcharge* (Case No. 2009-00197).

construction of these facilities at the E.W. Brown Generating Station ("Brown") and the Ghent Generating Station ("Ghent").

Overview of Testimony

Q. Please provide an overview of the testimony of the witnesses supporting KU's application in this proceeding.

A. In addition to my testimony, KU is presenting the testimony of five other witnesses in this case in support of its application. These witnesses and the subjects of their testimony are:

- John N. Voyles, Vice President, Transmission and Generation Services, presents testimony that describes the engineering and construction aspects of the projects in KU's 2011 Plan, and the operations and maintenance costs and savings for the projects. Mr. Voyles sponsors the 2011 Plan and the Environmental Air Compliance Strategy Summary for Kentucky Utilities Company and Louisville Gas and Electric Company.
- Gary H. Revlett, Director, Environmental Affairs, presents testimony discussing the environmental regulations that necessitate KU's 2011 Plan. Mr. Revlett describes the pertinent statutes, rules, or regulations requiring KU to take action.
- Charles R. Schram, Director, Energy Planning, Analysis and Forecasting, presents testimony on the cost-effectiveness of the projects in KU's 2011 Plan, and presents as exhibits the cost-benefit studies KU performed.
- Shannon L. Charnas, Director, Accounting and Regulatory Reporting, presents testimony affirming that the costs for which KU is seeking recovery through its Environmental Surcharge tariff are not included in base rates, and describes the

accounting associated with the projects in KU's 2011 Plan, all consistent with the Commission's prior orders.

- Robert M. Conroy, Director, Rates, presents KU's proposed Rate Schedule ECR and corresponding monthly reporting requirements, and presents testimony affirming that the calculation of KU's environmental surcharge will comply with all previous Commission Orders. Mr. Conroy also presents the revisions to the monthly ECR reporting forms that KU proposes, and explains why the revisions to the forms are appropriate. In addition, Mr. Conroy discusses the bill impact on KU's customers.

2011 Environmental Surcharge Plan and Recovery

Q. Please describe the 2011 Environmental Surcharge Plan KU proposes in this proceeding.

A. The projects in KU's 2011 Plan will serve Ghent and Brown. KU's 2011 Plan contains two new capital projects (along with their associated operating and maintenance ("O&M") expenses), as well as a modification to Project 29, which will permit KU to convert the current Brown Main Ash Pond to a dry-storage landfill for coal combustion residuals ("CCRs"). (KU's 2011 Plan is attached as Exhibit JNV-1 to Mr. Voyles's testimony.) Mr. Voyles's testimony presents KU's 2011 Plan, describes the need for the new projects in the plan (as well as the need for Amended Project 29), and provides the timeframe for construction of the projects. Mr. Revlett's testimony presents KU's evidence concerning the applicable environmental regulatory requirements and shows how the pollution control facilities in the 2011 Plan satisfy KU's environmental obligations. Mr. Schram's testimony provides evidence as to the cost effectiveness of the projects and details the estimated capital cost of $1.1 billion for the projects.

Q. Briefly, what are the environmental requirements giving rise to the projects in the 2011 Plan?

A. These projects are required for KU to comply with the federal Clean Air Act as amended ("CAAA"), the proposed Clean Air Transport Rule ("CATR"), the proposed national emission standards for hazardous air pollutants ("HAPs Rule"), the Resource Conservation and Recovery Act ("RCRA"), and other environmental requirements that apply to KU facilities used in the production of energy from coal, including the U.S. Environmental Protection Agency's ("EPA's") proposed regulation concerning the storage of CCR.

Q. Please describe Amended Project 29, which concerns the Brown Main Ash Pond.

A. While KU was in the process of expanding the Main Ash Pond at the Brown generating station, the EPA issued a proposed rule that, for the first time, would regulate CCRs under RCRA. As Mr. Revlett's testimony explains in detail, the proposed rule would regulate the manner in which electric utilities may store CCRs. Under the proposed rule, it is unlikely that the previously approved Project 29, which expands the existing Main Ash Pond, will comply with the new CCR requirements. To comply with the impending requirements, KU is seeking to amend the project to convert the Main Ash Pond to a dry-storage facility. The expected capital cost of the conversion is $59 million and will have associated O&M costs as shown on Exhibit JNV-1.

Q. What are the components of Project 34, and why are they necessary?

A. Project 34 consists of adding Particulate Matter Control Systems to serve all three Brown coal units. Each Particulate Matter Control System comprises a pulse-jet fabric filter ("baghouse") to capture particulate matter, a Powdered Activated Carbon ("PAC") injection system to capture mercury, and a lime injection system to protect the baghouses from the corrosive effects of sulfuric acid mist ("SAM"). Project 34 also includes installing SAM mitigation equipment consisting of sorbent injection systems on Brown Units 1 and 2 that are independent of the lime injection systems associated with the baghouses. (There is already a SAM mitigation system being installed on Brown Unit 3, which is part of the Selective Catalytic Reduction ("SCR") project the Commission approved as a part of KU's 2009 Plan, that is separate from the lime injection system that will be installed associated with the unit's proposed baghouse.[2]) These systems are necessary to meet the HAPs Rule's mercury and particulate emissions requirements. As Mr. Revlett's testimony explains in more detail, the SAM mitigation facilities are also necessary to meet the Title V SAM emissions requirement for Brown that arose from an EPA enforcement action.

The total projected capital cost of these facilities is $344 million: $109 million for Unit 1, $118 million for Unit 2, and $117 million for Unit 3. The projected annual O&M cost of these facilities (for which KU is seeking recovery through its environmental surcharge mechanism) is shown on the second page of Exhibit JNV-1 (an exhibit to Mr. Voyles's testimony).

The O&M amount for Brown Unit 3 is incremental to the amount already approved for recovery through the environmental surcharge mechanism for the unit's planned SAM mitigation system that is part of the Unit 3 SCR. The Commission approved the Brown Unit 3 SAM mitigation system as part of KU's 2009 Plan

[2] The Commission approved a SAM mitigation system as part of the scope of work on Project 28 for the Brown Unit 3 SCR in Case No. 2009-00178.

(Project 28). As Mr. Conroy explains in his testimony, KU proposes to report the already-approved Unit 3 SAM mitigation system's sorbent O&M costs as part of this project's SAM-sorbent-O&M costs.

Q. What are the components of Project 35, and why are they necessary?

A. First, Project 35 includes modifications to various systems at Ghent Units 1, 3, and 4 to expand the operating range of the units at which their SCR equipment can function to reduce nitrogen compound ("NO_X") emissions. The proposed modifications are required by the proposed CATR, which will impose stricter NO_X emissions requirements on KU and LG&E.

Second, Project 35 includes the addition of Particulate Matter Control Systems to serve all four Ghent units. Also included in Project 35 is the addition to Ghent Unit 2 of SAM mitigation equipment similar to that installed on Ghent Units 1, 3, and 4 under Project 24 (which the Commission approved as part of KU's 2006 Plan). In addition, the SAM mitigation equipment on Ghent Units 1, 3, and 4 will be upgraded. These systems and upgrades are necessary to meet the mercury emissions and particulate emissions requirements contained in the proposed HAPs Rule. As Mr. Revlett's testimony explains in more detail, the SAM mitigation facilities are also necessary to respond to certain EPA enforcement actions concerning opacity and Prevention of Significant Deterioration rules concerning Ghent.

The total projected capital cost of these facilities is $712 million: $164 million for Unit 1, $165 million for Unit 2, $198 million for Unit 3, and $185 million for Unit 4. The projected annual O&M cost of these facilities (for which KU is seeking recovery through its environmental surcharge mechanism) is shown on the second page of Exhibit JNV-1 (an exhibit to Mr. Voyles's testimony).

The O&M amounts for Ghent Unit 1, 3, and 4 are incremental to the amount already being collected through the environmental surcharge mechanism for the units' existing SAM mitigation systems. The Commission approved the Ghent Units 1, 3, and 4 SAM mitigation systems as part of KU's 2006 Plan (Project 24). As Mr. Conroy explains in his testimony, KU proposes to report the existing SAM mitigation systems' sorbent O&M costs as part of this project's SAM-sorbent-O&M costs.

Q. What evidence does KU present on the accounting of the cost for the 2011 Plan?

A. Ms. Charnas's testimony explains KU's reporting and accounting for the capital costs and operation and maintenance expenses associated with the pollution control facilities described in Mr. Voyles's testimony, and addresses KU's accounting for retirements and replacements associated with the 2011 Plan. Ms. Charnas further affirms that the environmental compliance costs KU proposes to recover through its surcharge are not already in existing base rates and will be accounted for consistent with prior Commission orders.

Q. What evidence does KU present concerning cost recovery and reporting under its ECR surcharge rider?

A. Mr. Conroy presents testimony to explain KU's changes to its monthly reporting requirements and affirming that the calculation of KU's environmental surcharge will comply with all previous Commission orders, including the calculation of operation and maintenance expenses. Mr. Conroy also presents the revisions to the monthly

ECR reporting forms that KU proposes and explains why the revisions of the forms are appropriate.

Also, KU is proposing some minor clarifying changes to its Environmental Cost Recovery Surcharge tariff. KU is filing its Environmental Cost Recovery Surcharge tariff for the purpose of obtaining the Commission's approval of the recovery of the costs of the 2011 Environmental Compliance Plan by the proposed assessment through this tariff. As further described in Mr. Conroy's testimony, the ECR tariff has an issue date of June 1, 2011, and is proposed to be effective on December 1, 2011. Therefore, bills issued on and after January 31, 2012, will reflect the revised environmental surcharge beginning with the expense month of December 2011.

Q. Why does KU's proposed 2011 Plan contain project elements that are necessary to comply with environmental regulations that are not yet final?

A. As Messrs. Voyles and Revlett explain in their testimony, though it is true that the EPA's proposed CCR regulation, CATR, and HAPs Rule are not yet final, it is prudent and in the interest of KU's customers to begin acting now to achieve compliance.

Concerning the amendment to Project 29 that would convert the Brown Main Ash Pond to a dry-storage landfill in response to the proposed CCR regulation, it is prudent at this point in the current ash pond expansion to stop and perform the conversion. Indeed, as the testimonies of Messrs. Voyles and Schram explain, conversion to a dry landfill now is cost-effective under any of the three alternatives contained in the proposed CCR regulation. Thus, though KU could proceed to complete the currently approved ash pond expansion while awaiting a final CCR rule, the more cost-effective and prudent approach is to perform the conversion now to avoid wasteful investment in further ash pond expansion work. As Mr. Schram's testimony shows, now is the time to make the switch.

With respect to CATR, the final rule is expected by July. Therefore, though the regulation is not final as of the date of this testimony, it should be final well before the end of this proceeding, so any necessary adjustments to KU's 2011 Plan that are responsive to CATR can be made before the Commission issues its final order. But as Mr. Revlett details, it is also unlikely that the final CATR will be less restrictive than the proposed rule; EPA has committed to eliminate the effects of interstate emissions on states' compliance with the National Ambient Air Quality Standards. It is also important to note that CATR is a successor regulation to the still-applicable Clean Air Interstate Rule. Thus, the clear trend of EPA regulation in this area is a tightening, not a loosening, of SO_2 and NO_X emission restrictions.

The situation is much the same concerning the proposed HAPs Rule. The EPA is under a court order to finalize the HAPs Rule by November 16, 2011, before the statutorily prescribed date by which the Commission must issue a final order in this proceeding. The HAPs Rule is the successor rule to the Clean Air Mercury Rule ("CAMR"), and it is more restrictive than CAMR was and it regulates more pollutants (mercury, hydrogen chloride, and particulate matter) than did CAMR. Moreover, as Mr. Voyles explains, KU does not have the luxury of waiting for the rule to become final before beginning to take action to comply because huge demand for the necessary compliance equipment and labor to install it necessitate entering the market as early as possible to ensure the most reasonable pricing and to obtain construction schedules that will permit timely compliance (to the extent such is possible).

In short, it is prudent and necessary to undertake the proposed actions now to comply with these currently proposed but soon-to-be final EPA regulations, all of which are rooted in the CAAA, RCRA, or in other laws relating to apply to coal combustion wastes and by-products resulting from the generation of electricity from coal.

Q. How do these projects affect KU's commitment to the responsible use of coal-fired generation?

A. The projects in the 2011 Plan reaffirm and strengthen KU's long-standing commitment to the efficient, safe, and environmentally responsible use of coal as a fuel source in its generating facilities. KU's commitment to coal use is evidenced by the type of power plants in which it has historically invested, and continues to invest, to meet its service requirements, consistent with the stated policy of Kentucky's General Assembly in KRS 278.020(1): "[It is] the policy of the General Assembly to foster and encourage the use of Kentucky coal by electric utilities serving the Commonwealth." Moreover, KU and LG&E recently demonstrated their long-term commitment to the safe, clean, and efficient use of coal by their significant investment in Trimble County Unit 2, a new 760 MW pulverized-coal super-critical unit employing state-of-the-art air pollution control equipment to ensure environmental compliance.

Return on Equity

Q. What return on common equity is KU currently authorized in its ECR tariff?

A. KU is currently authorized to earn a return on equity ("ROE") of 10.63 percent per the Commission's December 23, 2009 Order in Case No. 2009-00197 and the Commission's July 30, 2010 Order in Case No. 2009-00548.

Q. What ROE is KU requesting in this proceeding?

A. The Company is requesting continuation of the 10.63 percent ROE. In KU's 2009 rate case, all of the parties to the case except the Attorney General stipulated that the 10.63 percent ROE should continue to be used in KU's monthly environmental surcharge filings.[3] The Commission's Final Order in that proceeding accepted the terms of the Stipulation, including the agreed upon 10.63 percent ROE for environmental surcharge filings.[4] The approved stipulation in the Company's most recent base rate case has thus eliminated the controversy often associated with this issue.

Q. How does KU propose to recover the cost of the pollution control projects in its 2011 Plan?

A. KU proposes to recover the cost of the pollution control projects in its 2011 Plan through KU's Rate Schedule ECR filed with this application and proposed to be effective for bills rendered on or after January 31, 2012 (i.e., for expense months beginning with December 2011). The testimony of Mr. Conroy explains how the surcharge for the 2011 Plan will be calculated and billed under KU's proposed changes in the terms of Rate Schedule ECR and affirms that the calculation will be consistent with the methods and methodologies previously approved by the

[3] *In the Matter of: Application of Kentucky Utilities Company for an Adjustment of Base Rates* (Case No. 2009-00548), Stipulation, June 8, 2010 at p. 4.
[4] *Id.* at Final Order, July 30, 2010 at p. 11, 34.

Commission. Also, Mr. Conroy's testimony discusses changes to KU's monthly ECR filing forms.

Q. What revenue allocation is KU proposing in this case?

A. KU is proposing to use total revenues (including base rate, fuel adjustment clause, and demand-side management revenues) to allocate the environmental surcharge revenues, consistent with Commission precedent. The Commission has frequently used a percentage-of-revenues methodology in the absence of a cost-of-service study. Base rate revenues, however, continue to be allocated based on cost-of-service principles, methodologies, and studies. As I noted in my testimony in Case No. 2009-00548, given the importance of industrial customers to Kentucky's economy (i.e., providing jobs and tax revenues), and given the amount of KU's proposed investment in ECR facilities compared to KU's current rate base, revenue allocations that balance the interests of all customers may merit consideration.

<u>Certificates of Public Convenience and Necessity</u>

Q. Is KU requesting CPCNs in this proceeding?

A. Yes. KU is seeking seven CPCNs, one for each of the Particulate Matter Control Systems KU proposes to build to serve the Brown and Ghent generating units.

Q. How does the proposed construction meet the requirements for CPCNs set out in 807 KAR 5:001 § 9(2)?

A. As described in greater detail in the testimony of Messrs. Voyles and Revlett, each of the proposed Particulate Matter Control Systems is necessary to comply with EPA's HAPs Rule and SAM-emission restrictions for Brown and Ghent. As Messrs. Voyles and Revlett further describe, the HAPs Rule's requirements will, barring an unprecedented presidential intervention, be binding on KU no later than four years after EPA issues its final rule (which is expected to be no later than November 16, 2011).

Furthermore, without the proposed Particulate Matter Control Systems, KU could not operate the Brown or Ghent units under the HAPs Rule. The continued service of these units for KU's customers is in the public interest; as Mr. Schram's testimony shows, it is more cost-effective to continue to operate the units (including the cost of the proposed construction) than to retire the units and replace their capacity and energy with purchased power. Moreover, the proposed construction is not wastefully duplicative—no comparable facilities exist at Brown or Ghent—nor will it unnecessarily encumber the landscape because the facilities will be physically adjacent to existing generating-unit-related facilities on the Brown and Ghent properties. And there is no facility or other utility with which the proposed construction will compete.

Concerning the remaining CPCN requirements, Mr. Voyles's testimony further provides a full description of the proposed Particulate Matter Control Systems and their projected capital and operation and maintenance costs. Mr. Revlett's testimony addresses the necessary environmental permit applications. Finally, the Application itself contains the maps required for each requested CPCN.

Q. May the Commission grant KU the CPCNs it requests before the permitting process is complete?

A. Yes, the Commission may grant the requested CPCNs before the permitting process is complete. KRS 278.020(1) states that a CPCN shall expire within one year of the Commission's granting thereof, "exclusive of any delay due to the… failure to obtain any necessary grant or consent..." The statute therefore clearly anticipates situations in which the Commission may grant CPCNs prior to the CPCN applicant's having obtained all other necessary permits.

Q. How does KU plan to finance construction of the Particulate Matter Control Systems?

A. KU expects to finance the costs of the new facilities with a combination of new debt and equity. The mix of debt and equity used to finance the project will be determined so as to allow KU to maintain its strong investment-grade credit rating. To the extent that tax-exempt financing may be available for these projects, the Companies anticipate using such opportunities to the extent that they are reasonably cost-effective.

Q. Does KU need to begin preparing for construction of the Particulate Matter Control Systems prior to being granted a CPCN in this proceeding?

A. Yes, as Mr. Voyles explains in more detail in his testimony. KU understands that, pursuant to KRS 278.020(1), it may not "begin the construction" of any facility for which a CPCN is required until this Commission issues an order authorizing and approving the construction. KU appreciates the importance of this statute and has adhered to it with regard to the Particulate Matter Control Systems. Although KU will not begin construction of the proposed facilities prior to being granted a CPCN, the Company has engaged in preliminary actions, such as planning and contracting for certain parts of the work. KU was compelled to commence these activities prior to resolution of this proceeding because, absent such progress, the Company would not complete the facilities in the time set forth in the HAPs Rule, which would ultimately result in KU being forced to shut down the operation of some of its plants for noncompliance, as explained in the testimony of Messrs. Voyles and Revlett.

Q. In view of the tight compliance timeframe you have described, could KU have reasonably filed this Application sooner?

A. No, KU filed this Application at the earliest reasonable time, and has been working on the matters at issue in this Application for quite some time. As described in greater detail in the Environmental Air Compliance Strategy Summary for Kentucky Utilities Company and Louisville Gas and Electric Company (Exhibit JNV-2), the Companies retained the engineering firm Black and Veatch in May 2010 to conduct analyses about what kinds of steps they would need to take to comply with the proposed rules. In the case of the HAPs Rule, that meant retaining Black and Veatch well before EPA issued the proposed rule on March 16, 2011. So KU has moved with all reasonable and deliberate speed to file with the Commission an Application that contains proposals that will ensure KU's compliance with the proposed rules. Moreover, by filing now, KU has ensured that the CATR and HAPs Rule should be final before the Commission must issue its final order in this proceeding.

Conclusion and Recommendation

Q. What are your conclusion and recommendation to the Commission?

A. The face of environmental regulation relating to burning coal to generate electricity continues to change, and to change consistently in one direction; namely, the EPA and other environmental regulators continue to tighten restrictions on emissions and CCR storage options. Indeed, particularly with regard to the HAPs Rule, EPA is tightening environmental restrictions so dramatically and quickly that KU, LG&E, and other similarly situated utilities cannot afford to wait for the rules to become final before they act to comply. And the Companies must comply timely if they are to protect the investment made on behalf of their customers to provide safe, reliable, and relatively low-cost electric service in the future.

In view of this environmental regulatory regime, I recommend that the Commission grant KU its requested CPCNs to build Particulate Matter Control Systems to serve all the generating units at Ghent and Brown. I further recommend that the Commission approve KU's 2011 Plan, amendment to KU's Project 29, and application for cost recovery of its compliance costs through the Rate Schedule ECR tariff, as well as the proposed changes to its monthly forms beginning with the expense month of December 2011 and for bills rendered on and after January 31, 2012.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **Lonnie E. Bellar**, being duly sworn, deposes and says that he is Vice President, State Regulation and Rates for Kentucky Utilities Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Lonnie E. Bellar

Lonnie E. Bellar

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 27th day of May 2011.

Kimberly M Walters (SEAL)
Notary Public

My Commission Expires:

9/11/2012

APPENDIX A

Lonnie E. Bellar

Vice President, State Regulation and Rates
Louisville Gas and Electric Company and Kentucky Utilities Company
220 West Main Street
Louisville, Kentucky 40202
(502) 627-4830

Education

Bachelors in Electrical Engineering;
University of Kentucky, May 1987
Bachelors in Engineering Arts;
Georgetown College, May 1987
E.ON Academy, Intercultural Effectiveness Program: 2002-2003
E.ON Finance, Harvard Business School: 2003
E.ON Executive Pool: 2003-2007
E.ON Executive Program, Harvard Business School: 2006
E.ON Academy, Personal Awareness and Impact: 2006

Professional Experience

LG&E and KU Services Company	
Vice President, State Regulation and Rates	Nov. 2010 – Present
E.ON U.S. LLC	
Vice President, State Regulation and Rates	Aug. 2007 – Nov. 2010
Director, Transmission	Sept. 2006 – Aug. 2007
Director, Financial Planning and Controlling	April 2005 – Sept. 2006
General Manager, Cane Run, Ohio Falls and Combustion Turbines	Feb. 2003 – April 2005
Director, Generation Services	Feb. 2000 – Feb. 2003
Manager, Generation Systems Planning	Sept. 1998 – Feb. 2000
Group Leader, Generation Planning and Sales Support	May 1998 – Sept. 1998
Kentucky Utilities Company	
Manager, Generation Planning	Sept. 1995 – May 1998
Supervisor, Generation Planning	Jan. 1993 – Sept. 1995
Technical Engineer I, II and Senior, Generation System Planning	May 1987 – Jan. 1993

Professional Memberships

IEEE

Civic Activities

E.ON U.S. Power of One Co-Chair – 2007
Louisville Science Center – Board of Directors – 2008
Metro United Way Campaign – 2008
UK College of Engineering Advisory Board – 2009

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF KENTUCKY UTILITIES COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	))))))	**CASE NO. 2011-00161**

DIRECT TESTIMONY OF
JOHN N. VOYLES, JR.
VICE PRESIDENT, TRANSMISSION AND GENERATION SERVICES
KENTUCKY UTILITIES COMPANY

Filed: June 1, 2011

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

A. My name is John N. Voyles, Jr. I am the Vice President of Transmission and Generation Services for Kentucky Utilities Company ("KU"), and I am an employee of LG&E and KU Services Company, which provides services to Louisville Gas and Electric Company ("LG&E") and KU (collectively "the Companies"). My business address is 220 West Main Street, Louisville, Kentucky, 40202. A complete statement of my education and work experience is attached to this testimony as Appendix A.

Q. Please describe your job responsibilities.

A. I have 35 years of experience in the utility industry. In addition to oversight of the Transmission system, my current responsibilities include support of the generating fleet for both Companies with Generation Engineering and System Lab departments. I am also responsible for Project Engineering, the department that oversees large construction projects including generating stations, pollution control equipment, and on-site byproduct storage facilities. Prior to this assignment, I was the officer responsible for the generating fleet. Earlier in my career, I served as the corporate environmental director.

Q. Have you previously testified before this Commission?

A. Yes. I testified in the Companies' 2009 environmental compliance plan cases,[1] and I testified in a number of earlier proceedings, including LG&E's original application for recovery of its 1995 Environmental Compliance Plan.[2]

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

[1] Case Nos. 2009-00197 (KU 2009 ECR Plan) and 2009-00198 (KU 2009 ECR Plan).

[2] *In the Matter of: The Application of Louisville Gas and Electric Company for Approval of Compliance Plan and to Assess a Surcharge Pursuant to KRS 278.183 to Recover Costs of Compliance With Environmental Requirements For Coal Combustion Wastes and By-Products*, Case No. 93-332.

Exhibit JNV-1	Kentucky Utilities Company's 2011 Environmental Compliance Plan
Exhibit JNV-2	Environmental Air Compliance Strategy Summary for Kentucky Utilities Company and Louisville Gas and Electric Company (with appendices)
Exhibit JNV-3	Existing & Preliminary Future Air Quality Control Process Flow Diagrams (KU)
Exhibit JNV-4	E.W. Brown CCR Storage Evaluation Continue Main Pond Project vs. Conversion to Landfill

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the proposed pollution control projects contained in KU's 2011 Environmental Compliance Plan ("2011 Plan"). The 2011 Plan is attached to my testimony as Exhibit JNV-1 and sets forth each new pollution control project for which KU is seeking environmental surcharge recovery. These projects are required for KU to comply with the federal Clean Air Act as amended ("CAAA"), the proposed Clean Air Transport Rule ("CATR"), the proposed national emission standards for hazardous air pollutants ("HAPs Rule"), the Resource Conservation and Recovery Act ("RCRA"), and other environmental requirements that apply to KU facilities used in the production of energy from coal, including the U.S. Environmental Protection Agency's ("EPA's") proposed regulation concerning the storage of coal combustion residuals ("CCR").

I will also be supporting KU's request for Certificates of Public Convenience and Necessity ("CPCNs") related to the proposed 2011 Plan projects by providing project details, including a description of the proposed projects, the timeframe for construction, and the estimated cost of the projects.

Project Overview and Description

Q. Please provide an overview of the projects in KU's 2011 Environmental Compliance Plan.

A. The two new projects (Projects 34 and 35) and one amended project (amended Project 29) contained on Page 1 of Exhibit JNV-1 are required in order for KU to comply with the CAAA, CATR, the HAPs Rule, the CCR regulation, certain EPA enforcement actions, and other environmental requirements applicable to KU power plants. The total capital cost of the amended and new projects in the 2011 Plan is estimated to be approximately $1.1 billion. KU is also seeking recovery of operating and maintenance expenses associated with new Projects 34 and 35 and the amended Project 29, as detailed on Page 2 of Exhibit JNV-1

Q. Please describe KU's 2011 Environmental Compliance Plan as shown in Exhibit JNV-1.

A. The new pollution control projects in KU's 2011 Plan are shown in Exhibit JNV-1. Page 1 of Exhibit JNV-1 lists the capital costs associated with KU's compliance plan.

Column 1 assigns a number to the project for identification purposes in sequence with the projects from Case No. 93-465 (1 through 15),[3] Case No. 2000-439 (16 and 17),[4] Case No. 2002-00146 (18),[5] Case No. 2004-00426 (19

[3] *In the Matter of: The Application of Kentucky Utilities Company to Assess a Surcharge Under KRS 278.183 to Recover Costs of Compliance with Environmental Requirements for Coal Combustion Wastes and By-Products.*

[4] *In the Matter of: The Application of Kentucky Utilities Company for Approval of an Amended Compliance Plan for Purposes of Recovering the Costs of New and Additional Pollution Control Facilities and to Amend Its Environmental Cost Recovery Surcharge Tariff*

[5] *In the Matter of: The Application of Kentucky Utilities Company for Approval of Its 2002 Compliance Plan for Recovery by Environmental Surcharge*

through 22),[6] Case No. 2006-00206 (23 through 27),[7] and Case No. 2009-00197 (28 through 33).[8]

Column 2 describes the air pollutant or byproduct to be controlled.

Column 3 identifies the pollution control facility that KU plans to upgrade/construct to comply with the environmental regulations identified in Column 5.

Column 4 identifies the specific location of the pollution control facility.

Column 5 identifies the environmental regulation that requires KU to act on the associated project.

Column 6 identifies the environmental permits required for KU's projects to satisfy the environmental regulations.

Column 7 shows anticipated completion date of the specific project.

Column 8 displays the estimated capital cost of the project.

Page 2 of Exhibit JNV-1 lists the expected annual incremental operations and maintenance expenses associated with each project.

Column 1 assigns a number to the project for identification purposes in sequence with the projects from Case No. 93-465 (1 through 15),[9] Case No. 2000-439 (16 and 17),[10] Case No. 2002-00146 (18),[11] Case No. 2004-00426 (19

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[6] *In the Matter of: The Application of Kentucky Utilities Company for a Certificate of Public Convenience and Necessity to Construct Flue Gas Desulfurization Systems and Approval of Its 2004 Compliance Plan for Recovery by Environmental Surcharge.*

[7] *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 and Approval of Its 2006 Compliance Plan for Recovery by Environmental Surcharge.*

[8] *In the Matter of: The Application of Kentucky Utilities Company for Certificates of Public Convenience and Necessity and Approval of Its 2009 Compliance Plan for Recovery by Environmental Surcharge.*

[9] *In the Matter of: The Application of Kentucky Utilities Company to Assess a Surcharge Under KRS 278.183 to Recover Costs of Compliance with Environmental Requirements for Coal Combustion Wastes and By-Products.*

[10] *In the Matter of: The Application of Kentucky Utilities Company for Approval of an Amended Compliance Plan for Purposes of Recovering the Costs of New and Additional Pollution Control Facilities and to Amend Its Environmental Cost Recovery Surcharge Tariff.*

[11] *In the Matter of: The Application of Kentucky Utilities Company for Approval of Its 2002 Compliance Plan for Recovery by Environmental Surcharge*

through 22),[12] Case No. 2006-00206 (23 through 27),[13] and Case No. 2009-00197 (28 through 33).[14]

Column 2 describes the air pollutant or byproduct to be controlled.

Column 3 identifies the pollution control facility that KU plans to upgrade/construct to comply with the environmental regulations.

Column 4 identifies the specific location of the pollution control facility.

Columns 5-13 identify the incremental annual operation and maintenance costs associated with each project (through 2020).

<u>Amended Project 29: E.W. Brown Generating Station Main Ash Pond Conversion</u>

Q. What is the history of Project 29?

A. The history of Project 29 begins with Project 20, which the Commission approved as part of KU's 2005 Plan. Consistent with the 2006 ECR Update[15] to the 2005 Plan, Project 20 included an expansion of the existing E.W. Brown Station ("Brown") Main Ash Pond and the construction of an Auxiliary Pond (collectively, these construction items were called "Phase I" of a multi-phase overall project). The Auxiliary Pond was completed to the approved Phase I elevation of 880 feet in 2008 and the Main Ash Pond reached its Phase I approved elevation of 902 feet by mid-2010; however, further work on Phase I was put on hold when the EPA made its unprecedented announcement that it planned to regulate CCR under RCRA for the first time.

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[12] *In the Matter of: The Application of Kentucky Utilities Company for a Certificate of Public Convenience and Necessity to Construct Flue Gas Desulfurization Systems and Approval of Its 2004 Compliance Plan for Recovery by Environmental Surcharge.*

[13] *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 and Approval of Its 2006 Compliance Plan for Recovery by Environmental Surcharge.*

[14] *In the Matter of: The Application of Kentucky Utilities Company for Certificates of Public Convenience and Necessity and Approval of Its 2009 Compliance Plan for Recovery by Environmental Surcharge.*

[15] The 2006 ECR Update to the 2005 Plan was presented to the Kentucky Public Service Commission on March 10, 2006

KU proposed Project 29 ("Phase II") of the long-term Brown CCR storage plan as part of KU's 2009 Plan. Phase II was to consist of building the Auxiliary Pond to a final elevation of 900 feet and the Main Ash Pond to the next elevation of the multi-phase project to an elevation of 912 feet. At an elevation of 900 feet, the Auxiliary Pond was projected to contain sufficient capacity for bottom ash storage for approximately 30 years. The Main Ash Pond was to have approximately 6 years of projected remaining capacity after reaching an elevation 912 feet in 2012, with subsequent increased elevations as required for the overall 30-year-life design.

Q. What is the current status of Project 29?

A. In June 2008, the Brown Auxiliary Pond was placed into operation at elevation 880 feet. Shortly thereafter, the Main Ash Pond was taken out of service to allow the planned de-watering of the Main Ash Pond to occur. To date, excavation and pumping operations of the Main Ash Pond have been performed to drain the low-lying areas allowing the existing ash surface to be stabilized and re-graded. A bi-axial geo-grid reinforced working platform and a starter dike were constructed utilizing shot rock to be the foundation for future phased elevation expansions. Also completed are the new riser structure, a storm water runoff system, clay borrow and bottom ash stockpiling, and liner system procurement.

In June 2010, following EPA's issuance of its proposed CCR regulation (as described in Gary H. Revlett's testimony), KU suspended most of the work on the Brown Main Ash Pond in an effort to minimize construction of pond structures that could be rendered obsolete by the proposed regulation's requirements. Since that time, KU has proceeded only with construction activities that could be useful in either a proposed CCR-regulation-compliant landfill or the pond as originally approved in Project 29.

Q. What is KU's proposal to amend Project 29?

A. KU proposes to convert the Brown Main Ash Pond to a dry-storage CCR landfill for CCR to comply with pending regulations by the EPA for long-term storage of CCR. As Mr. Revlett points out, this approach should comply with all of the proposed rules contained in the CCR regulation proposed rulemaking, regardless of whether EPA ultimately classifies CCR as a hazardous or non-hazardous waste under RCRA.

The amendment to Project 29 would consist of accelerating the construction of the Auxiliary Pond to its final Phase II height using rock stockpiled or mined on plant property for work on the Main Ash Pond, continued ash grading within the Main Ash Pond footprint, capping the Main Ash Pond with a flexible synthetic membrane liner, conducting landfill engineering and permitting activities, converting all station ash handling systems from wet to dry, and constructing the initial phase of the landfill. This work will optimize the footprint of the dry-storage landfill within the footprint of the closed Main Ash Pond. Utilizing the footprint of the closed Main Ash Pond for the dry storage landfill allows vertical expansion opportunities in the future if required. We anticipate it will require 2.5 years to perform these activities, including the first phase of the landfill construction, with an expected in-service date of January 2014.

During this process, all the Brown units' effluents and CCR will continue to be directed to the Auxiliary Pond during the design, permitting, and construction of the landfill, which will enable the Brown units to continue to operate. Based on a recent bathymetric survey conducted by MACTEC, and utilizing the 2010 CCR production rates, the Auxiliary Pond has enough remaining capacity to store all the CCR generated at Brown through January 2014, though this is a conservative estimate; there should be sufficient Auxiliary Pond capacity to store all of the Brown effluent and CCR for a year beyond that should it be necessary.

Q. What would be the consequence of not acting now to convert the Brown Main Ash Pond to a dry-storage landfill?

A. If KU does not act soon to convert the Brown Main Ash Pond to a dry-storage landfill, work must resume completing the already-approved phases of the Main Ash Pond expansion so it can be ready to receive additional CCR before the Auxiliary Pond runs out of storage capacity. Completing the approved phases of the Main Pond expansion will require a capital expenditure of approximately $10 million, a portion of which would be stranded if the EPA ultimately treats CCR as a hazardous or solid waste under RCRA and does not grandfather existing ash ponds. Moreover, converting the Main Pond to a dry-storage landfill after the 2 currently approved pond expansion phases are complete will require capital investments ranging from $30 million to $40 million more than the $59 million KU projects will be necessary to convert the pond from its current state.

It is important to note that only the Main Ash Pond expansion phases completed at the time the proposed CCR regulation becomes final would be "grandfathered" under the most lenient of the three regulatory alternatives contained in the proposed rulemaking (the so-called "D-prime" alternative; under either of the other two proposed regulatory schemes, there would be no such grandfathering of existing ash ponds). Even if the approved second expansion phase of the Main Ash Pond could be completed before the CCR regulation becomes final (and grandfathering were possible), it would create only a portion of the long-term CCR storage solution for Brown. A dry landfill would still be needed to meet the storage needs for Brown, but it would be at a higher cost because a portion of the available footprint for the dry landfill would have been consumed by the Main Ash Pond expansion. This would then require the purchase of land near the station to allow development of a new landfill and the long-term trucking of CCR off-site to the new landfill.

The analysis of different options KU considered concerning the Brown Main Ash Pond (Exhibit JNV-4) and the cost-benefit analysis Charles R. Schram discusses in his testimony detail why KU is recommending converting the Brown Main Ash Pond now.

KU Air Compliance Projects

Q. How did KU determine what to include in its air compliance projects?

A. As more fully explained in the Environmental Air Compliance Strategy Summary for Kentucky Utilities Company and Louisville Gas and Electric Company (attached hereto as Exhibit JNV-2), the components of KU's proposed air compliance projects are the result of an intensive assessment and ongoing engineering effort by the Companies' Project Engineering group and outside engineering firms, most notably Black and Veatch. In response to (and, to some extent, in anticipation of) EPA's proposed air regulations and for budgeting purposes, the Companies retained Black and Veatch in May 2010 to assist in providing a rough order-of-magnitude estimate of the air quality compliance expenditures that would be required for each generating unit to meet expected future regulatory requirements. The Companies' Project Engineering group, under my supervision, worked with Black and Veatch through two phases of initial engineering to develop unit-by-unit compliance options. Once that was accomplished, the Companies' Generation Planning group performed an analysis to determine if all of the unit-by-unit compliance equipment would be necessary to achieve compliance with the applicable air regulations. The results of that analysis were used to pare down and refine the compliance equipment to be included in each project (for example, we were able to eliminate SCRs for certain units from the 2011 Plan). Generation Planning then determined for each generating unit if it would be more cost-effective to put in place the suite of compliance facilities established or to retire the unit. (Mr. Schram's testimony and its attachments contain the full details of that analysis.)

What KU is presenting in its 2011 Plan is, therefore, a cost-effective means of complying with the applicable air regulations.

<u>Project 34: Brown Air Compliance</u>

Q. What are the components of Project 34, and why are they necessary?

A. Project 34 consists of addition of Particulate Matter Control Systems to serve each of the Brown units. Each Particulate Matter Control System comprises a pulse-jet fabric filter ("baghouse") to capture particulate matter, a Powdered Activated Carbon ("PAC") injection system to capture mercury, a lime injection system to protect the baghouses from the corrosive effects of sulfuric acid mist ("SAM") and other balance-of-plant support system changes (e.g. ash collection/transport systems and fans). These Particulate Matter Control Systems will be similar to the baghouse (including the lime and PAC injection systems) installed at Trimble County Unit 2

("TC2") as part of its overall air quality control system (which the Commission approved as part of KU's 2006 Plan).[15] As Mr. Revlett's testimony explains, these systems are necessary to meet the mercury and particulate emissions reduction requirements contained in the proposed HAPs Rule.

Project 34 also includes installing SAM mitigation equipment consisting of sorbent injection systems on Brown Units 1 and 2 that are independent of the lime injection systems associated with the baghouses. (There is already a SAM mitigation system being installed on Brown Unit 3, which is part of the SCR project the Commission approved as a part of KU's 2009 Plan, that is separate from the lime injection system that will be installed associated with the unit's proposed baghouse.[16]) The SAM mitigation systems for Brown Units 1 and 2 are also necessary to meet the Title V SAM emissions requirement for Brown that arose from an EPA enforcement action, as Mr. Revlett's testimony explains.

The Commission approved the Brown Unit 3 SAM mitigation system as part the scope of work for Project 28 of KU's 2009 Plan. As Robert M. Conroy explains in his testimony, KU proposes to report the Brown Unit 3 SAM mitigation system's sorbent O&M costs as part of Project 34's SAM-sorbent-O&M costs. One reason for that approach is that, as a practical matter, KU cannot track separately the SAM sorbent being used by multiple environmental facilities related to different ECR projects at the same generating unit. Also, as Shannon L. Charnas explains in her testimony, each generating unit's SAM sorbent costs are recorded in the same

[15] *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).
[16] The Commission approved a SAM mitigation system as part of the scope of work on Project 28 for the Brown Unit 3 SCR in Case No. 2009-00178.

subaccount, making it very difficult to determine with reasonable certainty how much SAM sorbent cost should be reported for each project.

Exhibit JNV-3 contains a line-drawing schematic diagram of the existing and proposed components of the entire flue-gas stream for each Brown generating unit.

Project 35: Ghent Generating Station Air Compliance

Q. What are the components of Project 35, and why are they necessary?

A. First, Project 35 includes modifications to various systems at Ghent Generating Station ("Ghent") Units 1, 3, and 4 to expand the operating range of the units at which their existing Selective Catalytic Reduction ("SCR") equipment can function to reduce nitrogen compound ("NOx") emissions. Currently, the SCRs can operate only when the Ghent units are operating at relatively high generating load levels due to the SCR requiring flue gas temperatures above approximately 630 degrees Fahrenheit. The proposed modifications would allow the SCRs to operate, and thus to remove NO_X, when the generating units are running at lower load levels. The proposed modifications will provide additional margin against the NO_X tonnage caps in the EPA regulations, thus deferring the need for additional SCR installations and supporting least-cost compliance with the proposed CATR, which will impose stricter NO_X emissions requirements on LG&E and KU.

Second, Project 35 includes the addition of Particulate Matter Control Systems to serve each of the four Ghent units. Like the Particulate Matter Control Systems for Brown, the Ghent Particulate Matter Control Systems will be similar to the comparable systems installed and operating at TC2. These systems are necessary to meet the mercury and particulate emission reduction requirements contained in the proposed HAPs Rule.

Also included in Project 35 is the addition to Ghent Unit 2 of SAM mitigation equipment similar to that installed on Ghent Units 1, 3 and 4 under Project 24 (which the Commission approved as part of KU's 2006 Plan). In addition, the SAM mitigation equipment on Ghent Units 1, 3, and 4 will be upgraded to include milling equipment and refinement in injection location and methodology to respond to certain EPA enforcement actions concerning opacity and Prevention of Significant Deterioration rules concerning Ghent (as Mr. Revlett explains in his testimony). For the same reasons given above concerning tracking SAM-sorbent-O&M costs at Brown, KU proposes to report the existing Ghent SAM mitigation systems' sorbent O&M costs as part of Project 35's SAM-sorbent-O&M costs.

Exhibit JNV-3 contains a line-drawing schematic diagram of the existing and proposed components of the entire flue-gas stream for each Ghent generating unit.

Q. Do the air quality systems for Projects 34 and 35 consist of components that, when taken together, will allow the applicable generating unit to operate in compliance with the environmental regulations?

A. Yes. I will describe the components of the air quality systems in Project 34 and 35 as they apply to specific generating units at the Brown or Ghent generation stations.

<u>Particulate Matter Control Systems for Project 34 (Brown) and Project 35 (Ghent)</u>

Q. Please describe in more detail the proposed Particulate Matter Control Systems for the Brown and Ghent units.

A. As I described above, each Particulate Matter Control System comprises a baghouse to capture particulate matter, a PAC injection system to capture mercury, and a lime injection system to protect the baghouse from the corrosive effects of SAM. KU proposes to install Particulate Matter Control Systems to serve all its coal-fired

Brown and Ghent units. The diagram in Figure 1 below illustrates the basic components of a Particulate Matter Control System. (The locations of such components in each unit's flue gas stream are shown in the process flow diagrams contained in Exhibit JNV-3.)

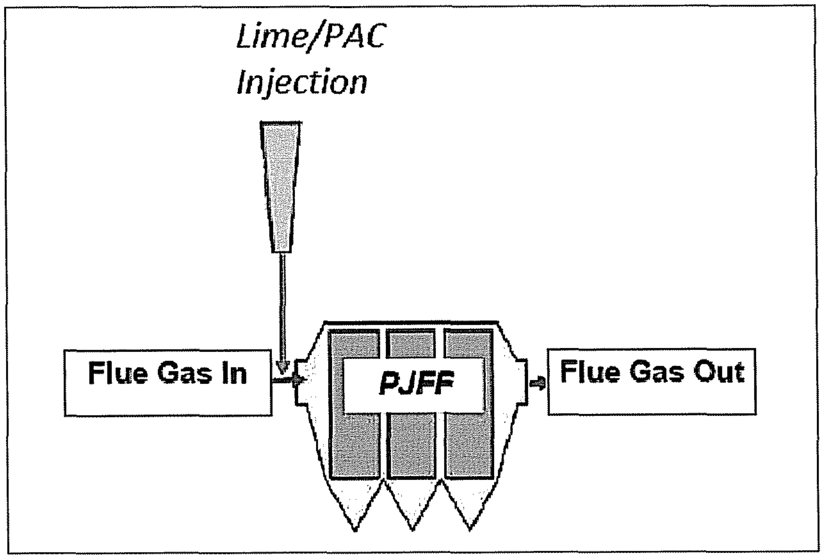


Figure 1: Particulate Matter Control Basic System Diagram

The first component of a Particulate Matter Control System is particulate-matter filtration via a fabric-filter baghouse. Baghouses like the ones KU proposes to install at Brown and Ghent can consistently achieve particulate matter emissions of less than 0.03 lb/MMBtu (the HAPs Rule's particulate matter emission limit) on a continuous basis, and will remove lime injection reagents, SAM and mercury-laden PAC, among other particulates to levels required by the regulations. Figure 2 below is an illustration of a typical baghouse.

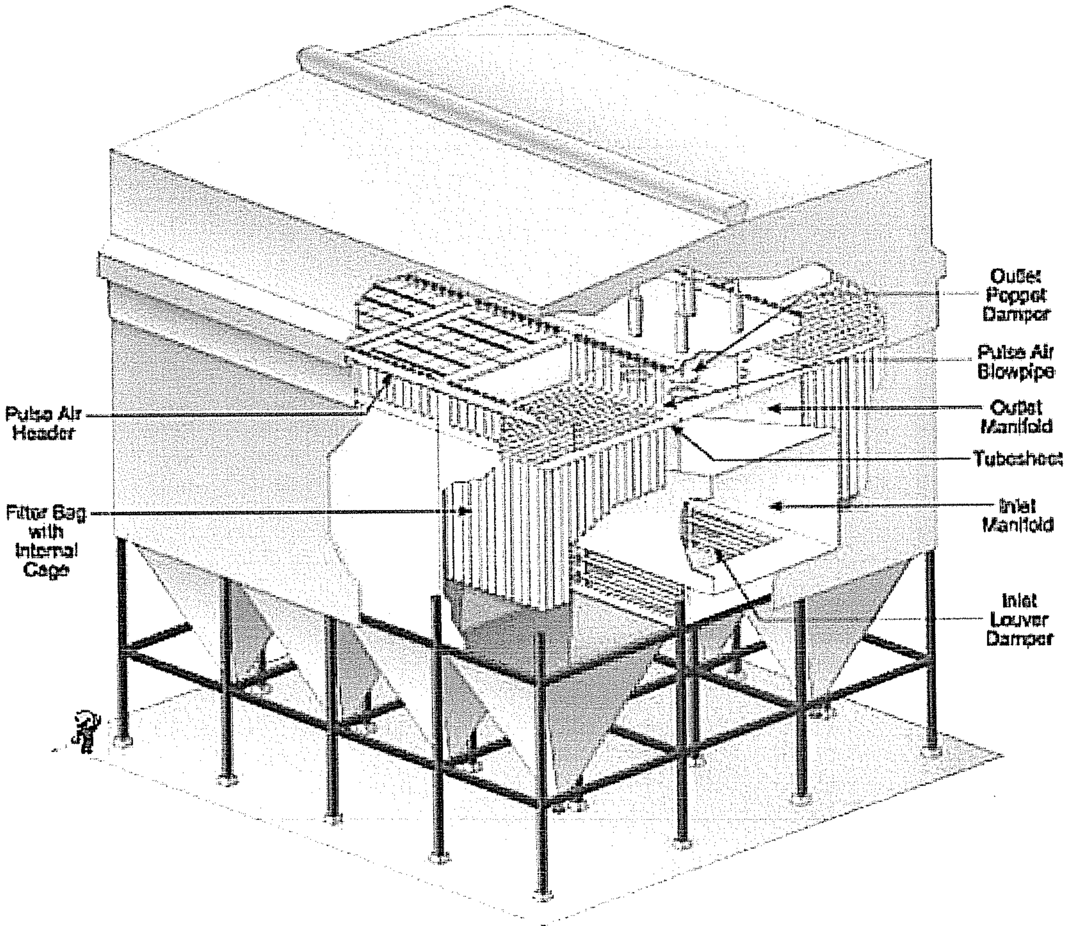


Figure 2: Illustration of a Typical Baghouse

The Particulate Matter Control Systems will impact other sub-systems at each unit. The addition of a baghouse will increase the pressure drop of the flue gas system. As such, each unit's draft system will require additional fan capacity accomplished through the replacement of induced draft fans currently installed or the addition of booster fans. The installation of larger fans or the addition of booster fans will likely require upgrades to the station's existing auxiliary power systems. Finally, each baghouse will require further engineering to determine the specific modifications on the current ash handling systems to accommodate new collection points.

The second component of a Particulate Matter Control System is a lime injection system. Lime injection ahead of the baghouse protects the internal components of the baghouse from the corrosive effects of SAM.

The third component of a Particulate Matter Control System is PAC injection. PAC injection is necessary to capture mercury in the flue gas stream. Elemental and oxidized forms of mercury collect on the powdered carbon and ash collected on the bags within the baghouse, making it possible for a downstream particulate control device (in this case, a baghouse) to capture the carbon-mercury compound. Each generating unit's PAC injection system will be installed immediately upstream of the baghouse. Coupled with baghouses, the PAC injection systems will be able to meet the proposed HAPs Rule's mercury emission limit of 1.2 lbs/TBtu (13 lbs/TWh) on a continuous basis as described in the testimony of Mr. Revlett.[17]

KU also proposes to install additional SAM-mitigating reagent injection systems that inject Trona or hydrated lime to remove SO_3 from the flue gas stream of each of Brown Units 1 and 2 and Ghent Unit 2, as well as to upgrade the existing SAM mitigation facilities at Ghent Units 1, 3, and 4 (As I mentioned above, Brown Unit 3 already has approved SAM mitigation that is being installed as part of the Brown Unit 3 SCR project, Project 28.). Burning high-sulfur, lower-cost coal can increase a generating unit's SAM emissions: sorbent injection can reduce SAM emissions on a continuous basis, mitigating the visible blue plume formation (and corresponding high opacity) from the chimney. These SAM mitigation systems would inject sorbent upstream and downstream of the existing dry electrostatic

[17] The mercury emission limit the EPA proposed in its HAPs Rule notice of proposed rulemaking was 1.0 lbs/TBtu (8 lbs/TWh). The EPA recently observed an error in its calculations and revised the proposed limit that would apply to the Companies' generating units. I have presented the revised limit above.

precipitators ("ESPs"). With the dry ESP upstream of the proposed baghouse for each unit, the ESP and baghouse can remove the SAM and sorbent introduced into each unit's flue gas stream.

Q. **Please describe the proposed construction schedules, capital costs, and operation and maintenance costs for the Particulate Matter Control Systems and SAM mitigation systems for the Brown and Ghent units.**

A. KU proposes to begin installing the SAM mitigation systems at Brown in early 2012, followed by the Particulate Matter Control Systems, with the total project being complete by the end of 2014 for Units 1 and 2, and mid-2015 for Unit 3. KU proposes to begin installing and upgrading the Ghent SAM mitigation systems late summer or early fall of 2011 and the work should be complete for Unit 1 by mid-2014, Unit 2 by late 2012, Unit 3 by late 2013, and Unit 4 by early 2014. KU proposes to begin installing the Ghent Particulate Matter Control Systems in mid-2012, and the work should be complete by mid-2014 for Unit 1, late 2014 for Unit 2, and late 2015 for Units 3 and 4.

The total projected capital cost of these facilities at Brown (Project 34) is $344 million: $109 million for Unit 1, $118 million for Unit 2, and $117 million for Unit 3. The projected annual O&M cost of these facilities at Brown are shown on page 2 of Exhibit JNV-1.

The total projected capital cost of these facilities at Ghent (part of Project 35) is $691 million: $157 million for Unit 1, $165 million for Unit 2, $191 million for Unit 3, and $178 million for Unit 4. The projected annual O&M cost of these facilities at Ghent are shown on page 2 of Exhibit JNV-1.

The O&M amounts for Brown Unit 3 and Ghent Units 1, 3, and 4 are incremental to the existing amounts already being collected through the environmental surcharge mechanism for the units' existing SAM mitigation systems. As I mentioned above, Mr. Conroy's testimony explains that KU proposes to report the O&M costs of Brown Unit 3's SAM mitigation system as part of Project 34's SAM-sorbent-O&M costs, and to report the O&M costs of Ghent Units 1, 3, and 4's SAM mitigation systems as part of Project 35's SAM-sorbent-O&M costs.

Project 35 Component: Modifications at Ghent to Expand Operating Range at which SCRs Can Function Efficiently

Q. Please describe the proposed modifications at Ghent Units 1, 3, and 4 to expand the units' operating range at which the SCRs can function to remove NO_X efficiently from the units' flue gas streams.

A. KU proposes to make a variety of modifications and adjustments at Ghent Units 1, 3, and 4 to expand the operating range at which the SCRs can function efficiently. Currently, the SCRs can operate efficiently when the Ghent units are operating at boiler exit gas temperatures above approximately 630 degrees Fahrenheit (which does not correlate with the lowest generating capacity output for these units). The proposed modifications would allow the SCRs to operate, and thus to remove NO_X, when the generating units are operating at lower load levels than those at which it is currently possible to run the SCRs. It is important to note that the SCRs were originally designed to operate under Title IV of the Acid Rain Rules, which focused on Ozone Season (May through September) NO_X emissions. During other periods of the year these baseload units operate at times in lower load ranges than the ranges that are typical during the summer peaking months.

The proposed modifications will provide additional margin against the NO_X tonnage caps in the EPA regulations, thus deferring the need for additional SCR installations and supporting least-cost compliance with the proposed CATR, which will impose stricter NO_X emissions requirements on LG&E and KU. Expanded operating ranges at high levels of NO_X reduction from the SCR when generating units are operating at lower load levels will consume fewer of the NOx allowances created by the CATR. Inside an SCR, once the operating temperatures meet the design levels, ammonia is injected and reacts with NO_X to form molecular nitrogen and water. Each SCR also contains a catalyst system, usually composed of tungsten and vanadium compounds configured in a honeycomb-plate arrangement, to enhance the reactions between the NO_X and ammonia. Usually there are two or three separate catalyst layers in sequence. With this sort of configuration, NO_X removal levels of over 90% are possible, but only when ammonia is injected.

The temperature of the incoming flue gas is vitally important to efficient SCR operation; at lower levels of generating unit operation, the flue gas entering an SCR typically is not high enough to utilize ammonia in the SCR efficiently. Ammonia injection is turned off at low boiler exit gas temperatures (below approximately 630 degrees Fahrenheit) which results in an increase in NO_X emissions from the unit even though the unit can continue to operate at a lower level of power output. Therefore, one way to expand the operating range at which an SCR can operate efficiently is to adjust the economizers (the last boiler circuit component) on a generating unit to keep the flue gas at higher temperatures when operating at lower load levels.

These changes will also have the benefit of allowing KU's generating units equipped with SCRs to be dispatched economically over a broader operating range after CATR goes into effect and fewer CATR NO_X allowances will be consumed. Having the ability to bring Ghent Units 1, 3, and 4 to lower operating levels while still having high degrees of NO_X removal will allow system operators greater flexibility to ensure economical generating system operation, ultimately resulting in cost savings for customers.

KU proposes to begin work on Unit 1 in late 2011, and the work should be complete by mid-2014. KU proposes to begin work on Unit 3 in late 2011, and the work should be complete by late 2013. KU proposes to begin work on Unit 4 in late 2011, and the work should be complete by mid-2014.

The total projected capital cost of this portion of Project 35 is $21 million: $7 million for Unit 1, $7 million for Unit 3, and $7 million for Unit 4. There is no additional O&M cost associated with these modifications.

Certificates of Public Convenience and Necessity

Q. Is KU seeking CPCNs for any of the facilities in its 2011 Plan?

A. Yes. KU is seeking seven CPCNs, one for each of the Particulate Matter Control Systems to serve each of the Brown and Ghent units. The testimony of Lonnie E. Bellar discusses in detail KU's request for CPCNs.

KU Must Begin Acting Now to Comply with CAAA, CATR and the HAPs Rule

Q. Why does KU propose to begin acting now to comply with EPA regulations like CATR and the HAPs Rule, which are not yet final?

A. As Mr. Revlett's testimony explains in detail, there is no reason to doubt that the proposed CATR and HAPs Rule will become final substantially in their current form.

The history of EPA's regulation of SO_2, NO_X, particulate matter, and ozone emissions from coal-fired power plants is consistently in the direction of tighter restrictions. The CATR and HAPs Rule are completely consistent with that history. Moreover, the CATR is scheduled to become final by July 2011, and the HAPs Rule is scheduled to become final by November 16, 2011, before a final order in this proceeding must be issued. (The date by which the HAPs Rule must become final is prescribed by a consent decree between EPA and the U.S. Department of Justice.) Because these proposed rules are highly likely to become final as proposed, and will become final soon, it is only prudent to begin taking steps now to comply with them.

As Mr. Revlett further explains, the compliance deadlines associated with these rules are inflexible: four years is the longest time KU will have to comply (barring presidential intervention, which has never occurred before). Four years is a tight timeframe in which to build, test, and ensure the operation of large, expensive, and complicated environmental control facilities that must work reliably for a single generating unit. It is much more complex to install this equipment on 12 units across the LG&E and KU system while trying to coordinate the necessary outage requirements. Delaying the project and attempting to install the systems on all 12 units at the same time is not feasible from an outage scheduling or from the equipment supplier market and construction labor viewpoint. That is particularly true concerning the HAPs Rule, which is effectively forcing the entire coal-fired electric generation industry to enter into the marketplace nearly simultaneously to acquire the same kinds of materials and labor KU will need. For that reason, moving now to stay at the front of the coming demand wave for equipment and labor to the extent it is reasonable to do so is the only prudent thing to do for our customers. Based on our experience for the last decade in the marketplace for environmental compliance facilities, locking in contracts and construction schedules in the near future should help to ensure that the necessary construction management, labor, and materials will be available to achieve timely compliance, and should help to mitigate materials and labor cost increases that could come with increased demand.

Moreover, failing to comply timely with these regulations will likely create significant cost burdens on our customers. If KU's units are not capable of operating in compliance with these regulations by the required time, they simply will not be able to operate; it would be illegal to operate them. To make up for any sidelined capacity and energy, KU would be forced to purchase power on the open market, a situation almost certain to result in higher costs for our customers.

That is why it is imperative to begin acting now to ensure timely compliance. By entering the marketplace now, KU will have the ability to achieve the greatest reasonably possible and timely compliance at competitive prices, and will be able to coordinate construction around scheduled unit outages to the extent it is feasible to do so. Nevertheless, KU will not enter into contracts for equipment or construction related to the 2011 Plan until the Commission issues a final order in this proceeding unless entering into one or more such contracts would be necessary to ensure timely environmental compliance or to avoid significant market price or equipment availability risks. This should result in continuing KU's ability to do what it has prided itself on doing throughout its history: providing reliable, relatively low-cost, environmentally compliant service to its customers.

Q. In view of the need to move swiftly to comply with CATR and the HAPs Rule, what is KU's contracting and construction strategy to ensure timely construction of the needed facilities?

A. KU has hired an outside engineering firm to assist in the development of specifications for the needed facilities. KU plans to begin this month with the request-for-quotations ("RFQ") process for the required equipment purchases with the initial focus on the baghouse and fan technologies. After conducting the RFQ processes, KU plans to approve the needed purchases during the 4th quarter of 2011 so that KU can assure equipment manufacturing space and delivery schedules are available from the necessary equipment suppliers. The contracts into which KU will enter to buy the needed equipment will have cancellation clauses with specific cancellation and deferment schedules based on cancellation/deferment of some, or all, specified equipment. These contracts will also have "regulatory out" clauses to permit the deferral or cancellation of equipment purchases contingent upon receiving necessary regulatory approvals (including the approval of this Commission) and further EPA action to issue final regulations. Depending on the cost and risk provisions obtained through competitive bidding of the engineering, procurement, and construction contracts ("EPC"), these large equipment purchase contracts will likely be assigned to the respective EPC firms for the various construction projects. (KU anticipates awarding the first EPC contracts in the first quarter of 2012.) In no event will actual construction begin on any of the 2011 Plan facilities until KU receives the Commission's final order in this proceeding.

All materials purchases, technology awards, EPC awards and construction firms' unit rates, base fees, and subcontracts will be competitively bid where the estimated cost exceeds $25,000.

Recommendation

Q. What is your recommendation to the Commission?

A. I recommend that the Commission approve KU's proposed 2011 Plan, cost recovery for the plan through KU's environmental surcharge mechanism, and the requested CPCNs. These facilities are necessary to comply with CATR, the HAPs Rule, the CCR regulation, and EPA enforcement actions at Brown and Ghent, and the construction timelines for these facilities necessitate that KU take swift action to begin contracting for and building the facilities before prices rise and the opportunity to have the facilities built in sufficient time to comply with the regulations passes.

Q. Does this conclude your testimony?

A. Yes it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **John N. Voyles, Jr.**, being duly sworn, deposes and says that he is Vice President, Transmission and Generation Services for Kentucky Utilities Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

John N. Voyles, Jr.

John N. Voyles, Jr.

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 27th day of May 2011.

Kimberly M Walters (SEAL)
Notary Public

My Commission Expires:

9/11/2012

APPENDIX A

John N. Voyles, Jr.

Vice President, Transmission and Generation Services
Louisville Gas and Electric Company and Kentucky Utilities Company
220 West Main Street
Louisville, Kentucky 40202
(502) 627-4762

Education

Rose-Hulman Institute of Technology, B.S. in Mechanical Engineering - 1976

Previous Positions

E.ON U.S. LLC

June 2008 - Present -Vice President, Transmission and Generation Services
2003 - 2008 -Vice President, Regulated Generation

LG&E Energy Corp.

February - May 2003 -- Director, Generation Services

Louisville Gas and Electric Company

1998 - 2003 -- General Manager, Cane Run, Ohio Falls and Combustion Turbines
1996 -1998 -- General Manager, Jefferson County Operations
1991 - 1995 -- Director, Environmental Excellence
1989 - 1991 -- Division Manager, Power Production, Mill Creek
1984 - 1989 -- Assistant Plant Manager, Mill Creek
1982 - 1984 -- Technical and Administrative Manager, Mill Creek
1976 - 1982 -- Mechanical Engineer

Professional Development

Emory Business School -- Management Development Program
Center for Creative Leadership (La Jolla, CA)
University of Louisville -The Effective Executive
Harvard Business School - Finance for the Non-Financial Manager
MIT - Leading Innovation & Growth: Managing the International Energy Co.

Board/Committee Memberships

Fund for the Arts - Board Member
Ohio Valley Electric Co. (OVEC) - Board member and Executive Committee member
Electric Energy, Inc. - Board member
Edison Electric Institute (EEI) - Committee member Energy Supply Executive Advisory Committee and the Environment Executive Advisory Committee
Electric Power Research Institute (EPRI) - Chairman, Research Advisory Committee

Exhibit JNV-1

KENTUCKY UTILITIES COMPANY
2011 ENVIRONMENTAL COMPLIANCE PLAN

Project	Air Pollutant or Waste/By-Product To Be Controlled	Control Facility	Generating Station	Environmental Regulation / Regulatory Requirement*	Environmental Permit*	Actual or Scheduled Completion	Actual (A) or Estimated (E) Projected Capital Cost ($Million)
29 Amended	Fly & Bottom Ash, Gypsum	Coal Combustion Residual Storage Landfill (conversion from wet to dry storage)	Brown Station	EPA CCR Regulations	Division of Waste Mgmt - Landfill Permit	2014	$58.67 (E)
34	NO_x, SO_3, Hg and Particulate	Baghouse with Powdered Activated Carbon Injection (shared Units 1 & 2, Unit 3); Sulfuric Acid Mist Mitigation (Units 1 and 2)	Brown Unit 1	Clean Air Act (1990), PSD Rules, EPA Consent Decree, and HAPS	Title V Permit	2014	$109.22 (E)
			Brown Unit 2			2014	$117.65 (E)
			Brown Unit 3			2015	$116.92 (E)
35	NO_x, SO_3, Hg and Particulate	Baghouse with Powdered Activated Carbon Injection (All Units), SCR Turn-Down (Unit 1, 3, 4), Sulfuric Acid Mist Mitigation (All Units)	Ghent Unit 1	Clean Air Act (1990), HAPS, CATR, KRS Chapter 224, PSD Rules	Title V Permit	2014	$164.21 (E)
			Ghent Unit 2			2012-2014	$164.55 (E)
			Ghent Unit 3			2013-2015	$198.01 (E)
			Ghent Unit 4			2014-2015	$184.76 (E)
							$1,113.99

* Sponsored by Witness Revlett

KENTUCKY UTILITIES COMPANY
2011 ENVIRONMENTAL COMPLIANCE PLAN

Project	Air Pollutant or Waste/By-Product To Be Controlled	Control Facility	Generating Station	Estimated Annual Operations and Maintenance Costs (Through 2020)								
				2012	2013	2014	2015	2016	2017	2018	2019	2020
29 Amended	Fly & Bottom Ash, Gypsum	Coal Combustion Residual Storage Landfill (conversion from wet to dry storage)	Brown Station	$ -	$ -	$ 2,813,772	$ 2,898,185	$ 2,985,131	$ 3,074,685	$ 3,166,925	$ 3,261,933	$ 3,359,791
34	NO_x, SO_3, Hg and Particulate	Baghouse with Powdered Activated Carbon Injection (shared Units 1 & 2, Unit 3); Sulfuric Acid Mist Mitigation (Units 1 and 2)	Brown Unit 1	$ -	$ -	$ 2,483,343	$ 4,809,135	$ 4,905,317	$ 5,003,424	$ 5,103,492	$ 5,205,562	$ 5,309,673
			Brown Unit 2	$ -	$ -	$ 5,052,836	$ 6,871,856	$ 7,009,293	$ 7,149,479	$ 7,292,469	$ 7,438,318	$ 7,587,085
			Brown Unit 3	$ -	$ -	$ -	$ 4,687,119	$ 7,171,292	$ 7,314,718	$ 7,461,012	$ 7,610,232	$ 7,762,437
35	NO_x, SO_3, Hg and Particulate	Baghouse with Powdered Activated Carbon Injection (All Units), SCR Turn-Down (Unit 1, 3, 4), Sulfuric Acid Mist Mitigation (All Units)	Ghent Unit 1	$ -	$ 2,730,914	$ 12,899,794	$ 17,179,567	$ 17,523,158	$ 17,873,621	$ 18,231,093	$ 18,595,715	$ 18,967,630
			Ghent Unit 2	$ 8,692	$ 1,276,696	$ 2,183,254	$ 12,112,005	$ 12,354,245	$ 12,601,330	$ 12,853,356	$ 13,110,424	$ 13,372,632
			Ghent Unit 3	$ -	$ 642,953	$ 4,721,847	$ 6,363,418	$ 17,537,222	$ 17,887,966	$ 18,245,725	$ 18,610,640	$ 18,982,853
			Ghent Unit 4	$ -	$ 3,578,918	$ 5,256,715	$ 5,848,876	$ 17,391,503	$ 17,739,333	$ 18,094,120	$ 18,456,002	$ 18,825,122

Exhibit JNV-2

Environmental Air Compliance Strategy Summary for Kentucky Utilities Company and Louisville Gas and Electric Company

PPL companies

May 2011

Environmental Air Compliance Strategy Summary

for Kentucky Utilities Company and Louisville Gas and Electric Company

Table of Contents

1.0 Executive Summary

In anticipation of, and response to, new and proposed regulations by the United States Environmental Protection Agency ("EPA"), Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, the "Companies") began a process in 2010 to explore technologies that would meet the expected requirements of the new emissions rules.

Black & Veatch ("B&V") was hired to assess each station on a unit-by-unit basis to identify the best technology to meet the expected new criteria. Through site visits, information exchanges, and an examination of their expansive database of past projects and available technologies, B&V developed options and cost estimates for the Companies to consider on an order-of-magnitude basis. (*See* Appendix A, Black & Veatch's *E.ON US Coal Fired Fleet Wide Air Quality Control Technology Cost Assessment* (July 2010).)

Additional engineering was required to ensure the Companies had enough information to make the appropriate selection of technology and to develop an overall environmental air compliance strategy. Therefore, the contract with B&V was extended to allow for a more thorough examination of the stations expected to be most affected by the EPA's proposed regulations (Mill Creek, Ghent, and E.W. Brown).

Additionally, other engineering and technology firms were engaged to assess upgrade opportunities on the existing Wet Flue Gas Desulfurization ("wet FGD") equipment at Mill Creek and to determine if Electrostatic Precipitator ("ESP") upgrades throughout the fleet would provide consistent emission removal rates required by the proposed regulatory standards.

After careful study and internal modeling, the Companies recommend that Pulse Jet Fabric Filters (also known as "baghouses") be installed on the coal-fired units at Mill Creek, Ghent, Brown, and Trimble County 1. A new wet FGD is proposed for Mill Creek Unit 4, and a new combined wet FGD is recommended for Mill Creek Units 1 and 2. Once the new Mill Creek Unit 4 wet FGD is placed into service, the old Unit 4 wet FGD will be refurbished and upgraded to provide scrubbing for Unit 3. After connecting Unit 3 to the upgraded Unit 4 FGD, the existing wet FGDs for Units 1, 2, and 3 will be demolished.

The strategy behind these decisions is detailed in the appendices to this document, which are reports by B&V and the Companies. This summary document highlights the main recommendations in the reports and explains the differences between what is in the reports and what the Companies are seeking approval for in their environmental surcharge applications.

2.0 Phase I Engineering Study

In May 2010, the Companies retained the services of B&V, a large, well-respected engineering firm, to assist in providing unit-by-unit order-of-magnitude budgetary estimates of air quality compliance expenditures needed to meet expected future regulatory requirements. To accomplish this, B&V and the Companies developed a plan that included collecting data and on-site observations at the Trimble County, Cane Run, Mill Creek, Ghent, Brown, and Green River Generating Stations necessary to conduct an air quality control technology retrofit and cost assessment. The focus of the unit-by-unit assessment was to identify the optimally cost-effective technologies for reducing air emissions of several pollutants: sulfur dioxide (SO_2), nitrogen oxides (NO_X), sulfuric acid (H_2SO_4, a precursor of which is SO_3), mercury (Hg), hydrogen chloride (HCl), hydrogen fluoride (HF), and other applicable metallic hazardous air pollutants. The EPA is requiring reductions in all the foregoing emissions through its new 1-hour SO_2 National Ambient Air Quality Standard ("NAAQS"), the proposed Clean Air Transport Rule ("CATR"), and the proposed national emission standards for hazardous air pollutants regulation ("HAPs Rule").

B&V provided a report to document the approach and findings of the assessment, which included identification of optimal retrofit Air Quality Control ("AQC") technologies to achieve compliance at each unit, as well as preliminary capital and operation and maintenance ("O&M") cost estimates and high-level implementation schedules to permit, procure, and install each recommended environmental Air Quality Control ("AQC") equipment retrofit. (See Appendix A.) This study did not include any system analyses to comply with regulations where aggregation of emissions was allowed, nor did the study include unit-specific schedules that were date-specific and coordinated with the fleet's generation outage schedules. Rather, it was an accelerated effort over a 3-4 week period designed to give the Companies a general, order-of-magnitude estimate to include in their 2011 financial planning process. Limited but sufficient engineering was conducted during this study to lay the groundwork for future planning.

Specifically, the Phase I study evaluated the following technologies for each unit to address all of the emissions listed above:

2.1 NO_X Reduction Technologies

B&V examined several possibilities for addressing NO_X reduction requirements. Low NO_X burners were reviewed because they reduce NO_X by maintaining a reducing atmosphere at the coal nozzle and diverting additional combustion air to secondary air registers. Over-Fire Air ("OFA") modifications involve an air staging NO_X reduction technique that is based on withholding 15-20 percent of the total combustion air conventionally supplied to the high-temperature zone of the furnace. The OFA systems reduce NO_X formation by creating a fuel-rich combustion zone where fuel burnout can be completed at a lower temperature with fewer volatile nitrogen-bearing combustion products.

Another technology that was examined was Selective Non-Catalytic Reduction ("SNCR"). This technology uses reagent injection in specific temperature zones of the boiler and reagent/gas mixing rather than a catalyst to achieve NO_X reductions. Alternatively, Selective Catalytic Reduction ("SCR") reduces NO_X by injecting ammonia into the flue gas stream that then reacts in the presence of catalyst and turns a significant portion of the NO_X into nitrogen and water.

SNCR/SCR hybrid systems are also applicable technologies for attaining NO_X reduction and generally have lower start-up costs. This approach combines components of both technologies in a manner that can meet initial NO_X reductions but also provides opportunities for upgrades to meet higher reductions if necessary.

After reviewing all of the potential choices, installing SCRs was the most cost effective, reliable, and efficient option for B&V to estimate. Low NO_X burner and OFA installations have already been installed on most of these units on past projects. The small gains in burner technology since these past modifications were installed would impact NO_X emissions, but not at a level that would consistently meet the requirements of pending regulations.

According to B&V, SNCR systems are less efficient NO_X reduction systems than SCR systems. In general, SNCR systems on large pulverized-coal-fired boilers will be capable of only up to 50 percent NO_X reduction in certain operational conditions. SNCR requires a operating in a specific temperature zone to be effective and this temperature zone is not achievable at the varying load ranges of the Companies' units to predict compliance with the NO_X regulations consistently. Catalyst volume is a strong factor in the design of hybrid systems and could drive the size of the system to require separate, additional factors in order to operate properly, which negates the advantages of a lower start-up cost.

Considering the alternatives, installing SCRs on the units in the system that currently would not meet new regulatory requirements was deemed the correct option for B&V to estimate in the original study.

2.2 Sulfur Dioxide (SO_2) and Hydrogen Chloride (HCl) Reduction Technologies

Three technologies were investigated to control SO_2 and HCl emissions: wet FGD, Spray Dry Absorber ("SDA"), and Circulating Dry Scrubber ("CDS"). All of these technologies use a reagent mixture to "scrub" SO_2 and HCl from the flue gas stream.

The SDA process is generally used in conjunction with boilers that use either lignite or sub-bituminous coal with a sulfur content of less than 2 percent. According to B&V, this system has an inherent removal efficiency limitation of 94 percent from inlet concentration. The Companies' generating units combust coals with higher levels of sulfur, thus this technology has limited benefits to meet the new regulations.

The CDS FGD is not a completely dry process as it uses water sprayed into the reactor to reduce the flue gas temperature to the optimal temperature for reaction of the SO_2 with the reagent. In this process, hydrated lime and recirculated dry solids are injected into the flue gas at the base of the reactor to achieve desired removal rates. This technology is an acceptable removal process, but it does have the disadvantage of imposing particulate load on the collectors downstream of the absorber.

Wet limestone FGDs are commonly used on pulverized-coal-fired burners that burn medium- to high-sulfur coal. This process works by injecting a limestone slurry mixture into the flue gas that absorbs SO_2 molecules so that the gas leaving the absorber is saturated with water. This process is extremely effective and allows for the potential of greater than 98% removal.

Wet FGD technology is currently used throughout the Companies' fleet and has proven to be a reliable process for consistent SO_2 removal. A co-benefit of installing a wet FGD is that the process removes HCl as well as SO_2. It is also the technology that best suits the quality of coal used in the Companies' facilities and therefore was the technology chosen in Phase I for further estimation by B&V.

2.3 Particulate Matter (PM) Reduction Technologies

Dry ESPs are the most common technology in use today for particulate matter control on coal-fired units. All of the Companies' generating units currently use ESPs, which work by using transformer/rectifiers to produce a high-voltage, direct-current electrical field that ensures particulate matter entering the field acquires a negative charge and then is collected on a grounding plate.

Fabric filters (commonly called baghouses) are another type of particulate-control technology that employs the use of one of two types of cleaning process, reverse-gas or pulse-jet. Reverse-gas technology is effective but requires a relatively large footprint for installation. Pulse-Jet Fabric Filters ("PJFFs") can operate at higher flue gas velocities and have a smaller footprint resulting in a lower capital cost.

Fabric filters use thousands of cloth bags that are placed in cylindrical tubes that are designed to capture particulate matter. The number of compartments and bags are determined by flue gas volume rate.

Lastly, a Compact Hybrid Particulate Collector was also investigated as a possible alternative for controlling particulate matter. This fabric filter operates using a similar cleaning process as other technologies but is installed after an existing cold-side ESP. When using this technology, the majority of the particulate matter is collected in the upstream ESP. An advantage of this system is that is uses a higher air-to-cloth ratio, which allows for a smaller footprint, thus lowering capital costs.

After examining the technology choices, the PJFF option was selected for further estimation as it also has a co-benefit of not only controlling particulate matter but also mercury (when used in conjunction with Powdered Activated Carbon ("PAC") injection, described below).

2.4 Mercury (Hg) and Dioxin/Furan Reduction Technologies

Research provided to the Companies by B&V shows that PAC injection is a mature technology used in other industries that has been shown to remove at least 90% of mercury in those applications. PAC injection systems are generally added upstream of PJFFs or dry ESPs and allow for mercury to be adsorbed onto the PAC. (Adsorption is the process by which a substance in a gas or liquid becomes attached to the surface a solid.) Additionally, a lime and PAC injection system in combination with a PJFF was installed on Trimble County Unit 2 and was selected as the best technology available to meet the applicable environmental regulations.

Because the PJFF with lime and PAC injection option offers the best technology to assist the Companies in meeting regulatory requirements for particulate matter and mercury removal, it was selected for further estimating by B&V.

2.5 Scheduling

Once the preliminarily optimal technologies were selected and B&V's report was evaluated, an implementation schedule was developed for planning purposes. The table below shows the technologies identified in this first level conceptual study necessary for each unit to individually comply with future air regulations.

Environmental Air Timeline
2011 Initial Plan

CATR by January 2015 (1 year Phase II delay), NAAQS by January 2016, HAPs by January 2017 (1 year delay)

	2012		2013		2014		2015		2016	
	H1	H2	H1	H2	H1	H2	H1	H2	H1	H2
Mill Creek 1						FGD Upgrade FF				SCR
Mill Creek 2				FGD Upgrade FF				SCR		
Mill Creek 3							4FGDU FF			
Mill Creek 4	SCR Upgrade				FGD/Stack FF					
Trimble County 1								FF		
Ghent 1									FF	
Ghent 2					SCR				FF	
Ghent 3								FF		
Ghent 4								FF		
Brown 1					SCR FF					
Brown 2				SCR				FF		
Brown 3									FF	

SO2	FGD - Flue Gas Desulfurization
NOx	SCR - Selective Catalytic Reduction
HAPs	FF - Pulse Jet Fabric Filter

3.0 Phase II Engineering Study

In late 2010, the contract with B&V was extended to continue maturing the previous fleet-wide, high-level air quality technology review and cost assessment in Phase I. The goal of the Phase II study was to confirm the technologies' feasibility from Phase I and to develop a station-specific project definition consisting of a conceptual design and budgetary cost estimate for selected air quality control technologies (Phase II). The Phase II scope of work focused initially on the Mill Creek, Ghent, and Brown facilities because it was determined through internal modeling that these units would be the best candidates for implementing the technologies required by the new environmental requirements at the least cost. Trimble County Unit 1 was not included in the B&V effort because the scope of work required for the unit was straightforward and smaller than the modifications for the other units. Trimble County engineering data and financials were carried through from Phase I to Phase II.

Phase II consisted of site meetings, environmental regulatory review, development of project design criteria, AQC technology validation and selection, overview of existing systems at each facility, development of the preliminary conceptual design, constructability review, structural steel review for Mill Creek Units 1 and 2, project cost estimates, and an evaluation report. The end result of the study is a preliminary document for each facility (Ghent, Mill Creek, and Brown) that is inclusive of the analyses conducted in the Phase I as well as sketches and conceptual drawings that illustrated the recommended engineering plan. (*See* Appendix B, Black & Veatch's *Phase II: Air Quality Control Study, Mill Creek Station, Draft Report dated March 2011*; Appendix C, Black & Veatch's *Phase II: Air Quality Control Study, Ghent Station, Draft Report dated April 2011*; Appendix D, Black & Veatch's *Phase II: Air Quality Control Study, E.W. Brown Station, Draft Report dated May 2011.*)

It is important to note that although these documents represent a higher level of engineering than what was conducted in Phase I, the information does not represent a final plan for each of the stations. Months of engineering, as well as partnering with technology vendors, are now underway to develop final, detailed design and construction plans; however, the basic components of the proposed suite of environmental compliance facilities for each unit will not change (e.g., the question whether to include a PJFF on a particular unit is resolved, but the precise physical size and placement of the PJFF or its impact on all balance of plant support systems is not yet final).

3.1 Phase II Technology Selections

In order to comply with the new HAPs Rule, it was determined that each unit at Brown, Ghent, Mill Creek, and Trimble County Unit 1 would be served by a PJFF with lime injection (to protect the PJFF from deterioration due to sulfuric acid mist ("SAM")) and PAC injection systems. This combination of technology would enable each station to meet consistently the most wide-ranging emissions restrictions (i.e., mercury, HCl, particulate matter, and Dioxin/Furan).

Upgrading the ESPs at the generating stations was also explored as an alternative to address the HAPs Rule's requirements. The Babcock and Wilcox Company was hired to support the Companies' personnel in a high level assessment of our current ESPs to determine if modifications or upgrades could be made that would increase our ability manage particulate matter emissions. (*See* Appendix E, *LG&E – KU Fleetwide ESP Study, April 2011 (Internal Electrostatic Precipitator Evaluation).*)

It was determined that ESP upgrades would be insufficient to comply with the HAPs Rule's mercury restriction. Essentially, capital would be spent to upgrade the ESPs but PJFFs (with PAC and lime injection) would still be required to comply with the HAPs Rule's mercury limit.[1] In fact, as the PJFFs are placed into operation, the additional particulate removal obtained through any ESP upgrades would be detrimental to the efficiency of the PJFFs. In other words, the PJFF needs more particulate, not less particulate, for the process to be most effective. The Companies determined the best course of action was to build the PJFF systems and forgo upgrades to the ESPs.

Lastly, as part of the Companies' effort to increase their knowledge and understanding of the technologies needed to comply with the latest EPA requirements, four PJFF technology vendors were brought in to conduct a workshop for key stakeholders in the company. A consistent message from the vendors was that there is a significant shortage of PJFF production capacity to meet the demand the proposed regulations have created.

In addition to the PJFFs planned at each of these stations, a new wet FGD for Mill Creek Unit 4 and a new combined wet FGD for Mill Creek Units 1 and 2 are also proposed. Although these units currently have wet FGDs, their existing SO_2 removal efficiency does not meet the emission criteria expected to be required by the new 1-hour SO_2 NAAQS.

To explore the upgrade options, the Companies also retained the services of Babcock Power Environmental, Inc. and Hitachi to individually conduct performance studies on the Mill Creek Units 1 and 2 wet FGDs to assess if the performance of those units could be improved to meet the standards of the new NAAQS regulations instead of requiring a new wet FGD for each unit. These preliminary studies showed that for a significant amount of capital investment, both existing wet FGDs theoretically could be modified to meet the expected minimum requirements for SO_2 removal. However, B&V conducted an additional study on the structural integrity of the existing wet FGD systems and these studies also showed that significant unit outages would be required to make the extensive structural steel, equipment, and infrastructure upgrades necessary to support the performance upgrades. Additionally, it was not expected that further

[1] This limit equates to 1.0 lb./TWh. On May 18, 2011, EPA issued a letter acknowledging that this emission limit is incorrect due to computational errors, and that a value of 1.2 lbs/TWh is correct. It still represents a "90 percent reduction from the mercury in the coal used by power plants."

modifications to the Units 1and 2 wet FGDs would provide a service life comparable to a new combined wet FGD to serve both generating units.

4.0 Phase I and Phase II Studies vs. Compliance Plan

As stated above, the Phase I and Phase II studies were conducted on a unit-by-unit basis and did not take into account any aggregation of emissions that might be allowed by the future regulations. The Companies' Energy Planning, Analysis and Forecasting department's first round of modeling indicated that the SCRs, and associated scope with the implementation of SCRs, identified in the Phases I and II studies would not be necessary to meet the CATR NO_X emission reductions for the generating fleet. Given this, the compliance plan scope was reduced by not including the SCRs identified in the studies, along with the SCRs' impacts on other capital and O&M expenditures.

Though SCRs were removed from the scope, smaller projects were added to the compliance plan to improve the range of unit operation of the existing SCRs. These smaller projects were estimated based on the Companies' past experience on similar projects and are not listed in the B&V studies. (*See* Appendix F, Black & Veatch's *Phase II: Air Quality Control Study, Mill Creek Station, Draft Report Addendum 1 dated April 2011*; Appendix G, Black & Veatch's *Phase II: Air Quality Control Study, Ghent Station, Draft Report Addendum 1 dated April 2011*; Appendix H, Black & Veatch's *Phase II: Air Quality Control Study, E.W. Brown Station, Draft Report Addendum 1 dated May 2011*.)

The compliance plan also includes sulfuric acid mist ("SAM") mitigation projects consisting of sorbent injection technology that was not studied through the B&V studies. The Companies' experience on similar projects approved by the Kentucky Public Service Commission in 2006 was used to develop the scopes and cost estimates for the Brown 1 and 2 and Ghent 2 systems.

The compliance plan also includes conceptual estimates to combine the new Mill Creek 1 and 2 wet FGDs into a single wet FGD instead of individual unit specific wet FGDs. This cost savings measure was developed by the Companies and evaluated by B&V separately from the studies to minimize the overall cost of the air compliance plan.

The final scope for the Companies' air compliance is shown in the table below and is based on the combination of the B&V studies and the Companies' recent experience on similar technologies and projects.

Environmental Air Timeline
2011 Proposed Plan

CATR by January 2014, NAAQS by January 2016, HAPs by January 2016

	2012		2013		2014		2015		2016	
	H1	H2	H1	H2	H1	H2	H1	H2	H1	H2
Mill Creek 1							Comb. 1&2 FGD FF			
Mill Creek 2							Comb. 1&2 FGD FF			
Mill Creek 3				SCR Turndown		4FGDU		FF		
Mill Creek 4	SCR Upgrade					FGD/Stack FF SCR Turndown				
Trimble County 1								FF		
Ghent 1					FF SCR Turndown					
Ghent 2						FF				
Ghent 3				SCR Turndown				FF		
Ghent 4					SCR Turndown			FF		
Brown 1					FF					
Brown 2					FF					
Brown 3							FF			

SO2	FGD - Flue Gas Desulfurization
NOx	SCR - Selective Catalytic Reduction
HAPs	FF - Pulse Jet Fabric Filter

5.0 Future Engineering Plans

The Companies have retained B&V to assist in the development of the technical specifications for new wet FGDs (Mill Creek) and PJFFs (E.W. Brown, Ghent, Mill Creek and Trimble County 1) and associated systems (i.e., lime injection, PAC injection, and fan upgrades/replacements). Additional work is also planned with B&V to refine further the engineering recommendations presented in their study. This additional work is expected to continue through 2011 as the Companies continue to refine the specifics of this compliance plan and begin the equipment procurement phase.

6.0 Appendices

Due to the voluminous nature of the reports listed below, please see the compact disk included with this filing.

- Appendix A: Black & Veatch's *E.ON US Coal Fired Fleet Wide Air Quality Control Technology Cost Assessment (July 2010)*
- Appendix B: Black & Veatch's *Phase II: Air Quality Control Study, Mill Creek Station, Draft Report dated March 2011*
- Appendix C: Black & Veatch's *Phase II: Air Quality Control Study, Ghent Station, Draft Report dated April 2011*
- Appendix D: Black & Veatch's *Phase II: Air Quality Control Study, E.W. Brown Station, Draft Report dated May 2011*
- Appendix E: *LG&E – KU Fleetwide ESP Study, April 2011 (Internal Electrostatic Precipitator Evaluation)*
- Appendix F: Black & Veatch's *Phase II: Air Quality Control Study, Mill Creek Station, Draft Report Addendum 1 dated April 2011*
- Appendix G: Black & Veatch's *Phase II: Air Quality Control Study, Ghent Station, Draft Report Addendum 1 dated April 2011*
- Appendix H: Black & Veatch's *Phase II: Air Quality Control Study, E.W. Brown Station, Draft Report Addendum 1 dated May 2011*

Exhibit JNV-3

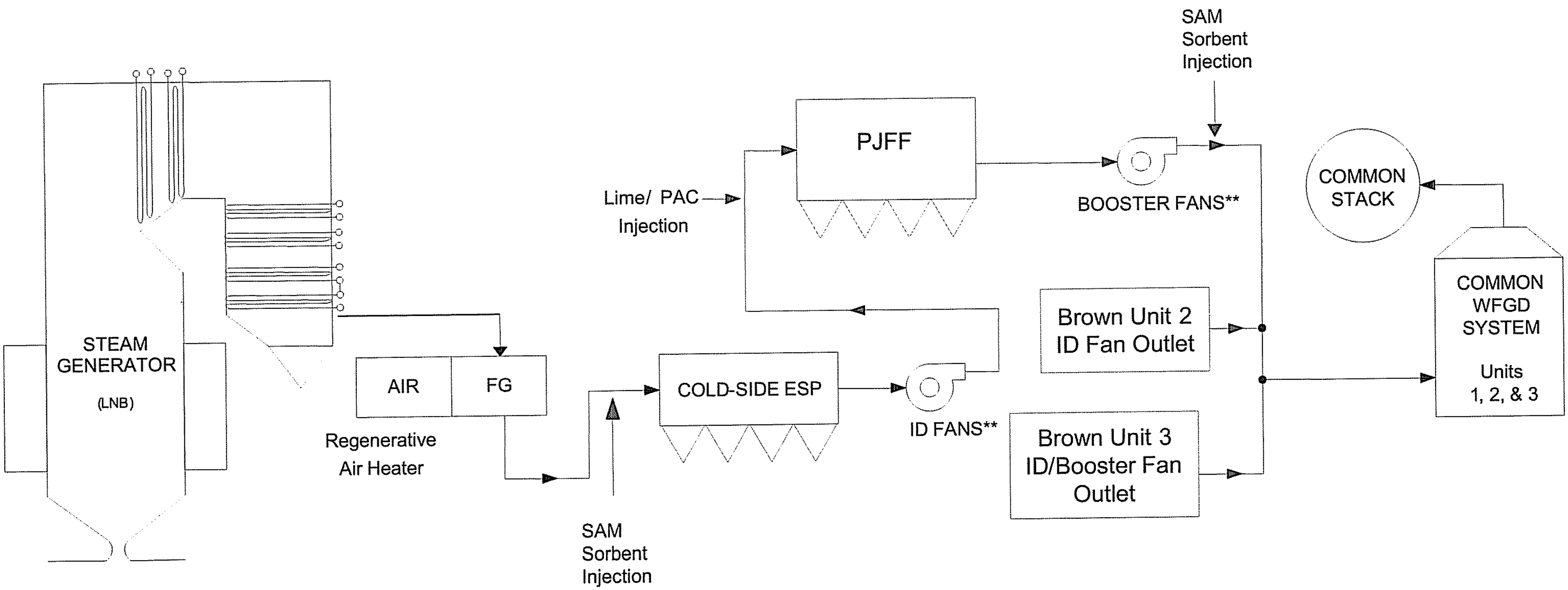
Existing & Preliminary Future Air Quality Control Process Flow Diagrams

For E.W. Brown and Ghent Generating Stations

LG&E KU
PPL companies

May 2011

EW Brown Unit 1
AQC Process Flow Diagram

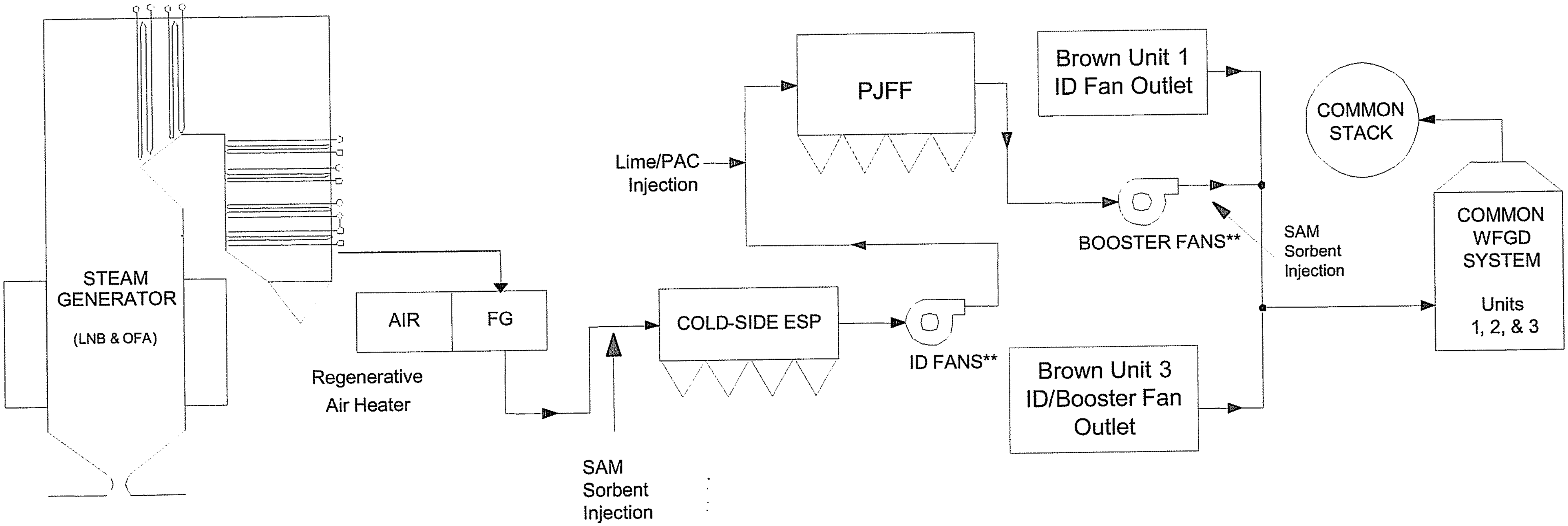


***Replacement to new Booster Fans or larger ID Fans is yet to be determined*

Black = Existing
Red = Preliminary Additions

May-11

EW Brown Unit 2
AQC Process Flow Diagram

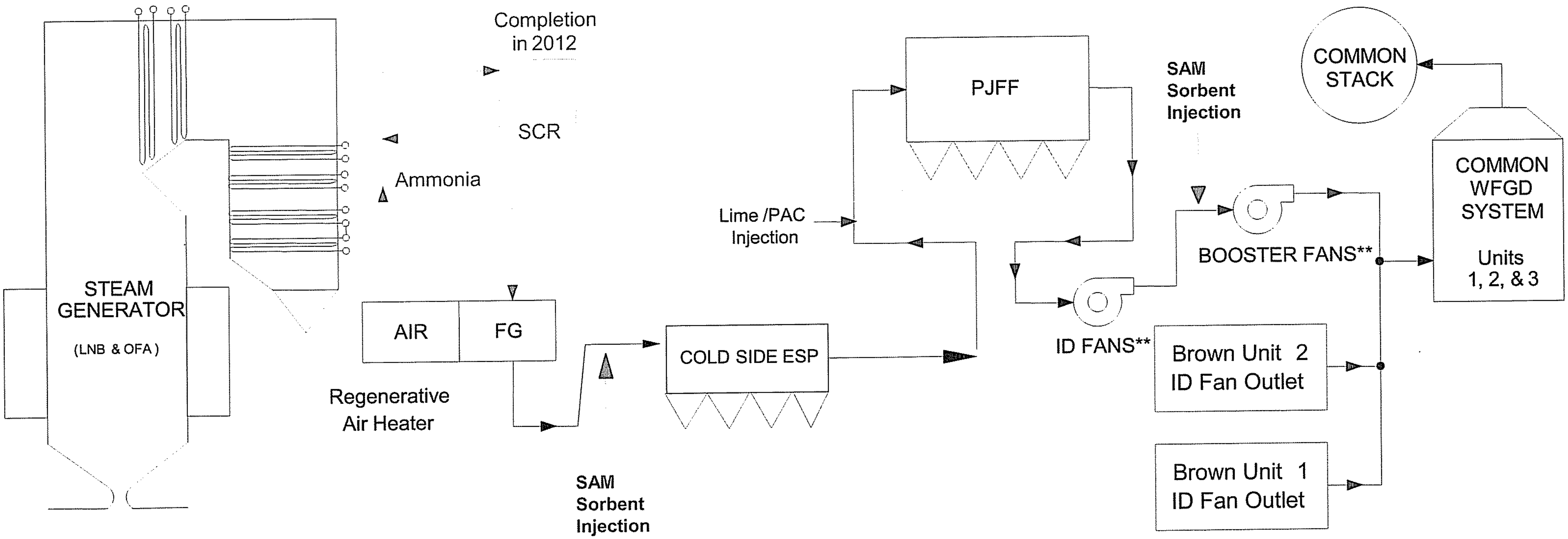


***Replacement to new Booster Fans or larger ID Fans is yet to be determined*

Black = Existing
Red = Preliminary Additions

May-11

EW Brown Unit 3
Process Flow Diagram

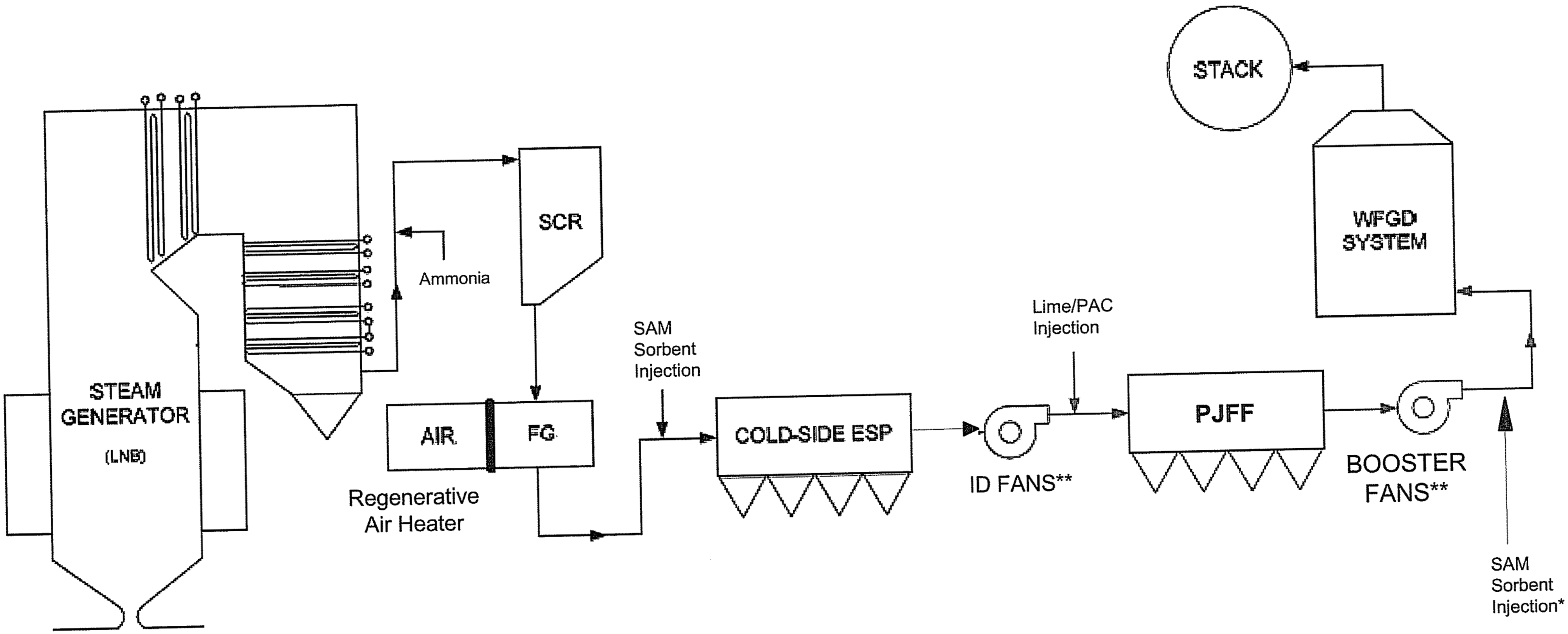


***Replacement to new Booster Fans or larger ID Fans is yet to be determined*

Black = Existing
Red = Preliminary Additions
Green = Preciously approved. Not yet installed.

May-11

Ghent Unit 1
AQC Process Flow Diagram

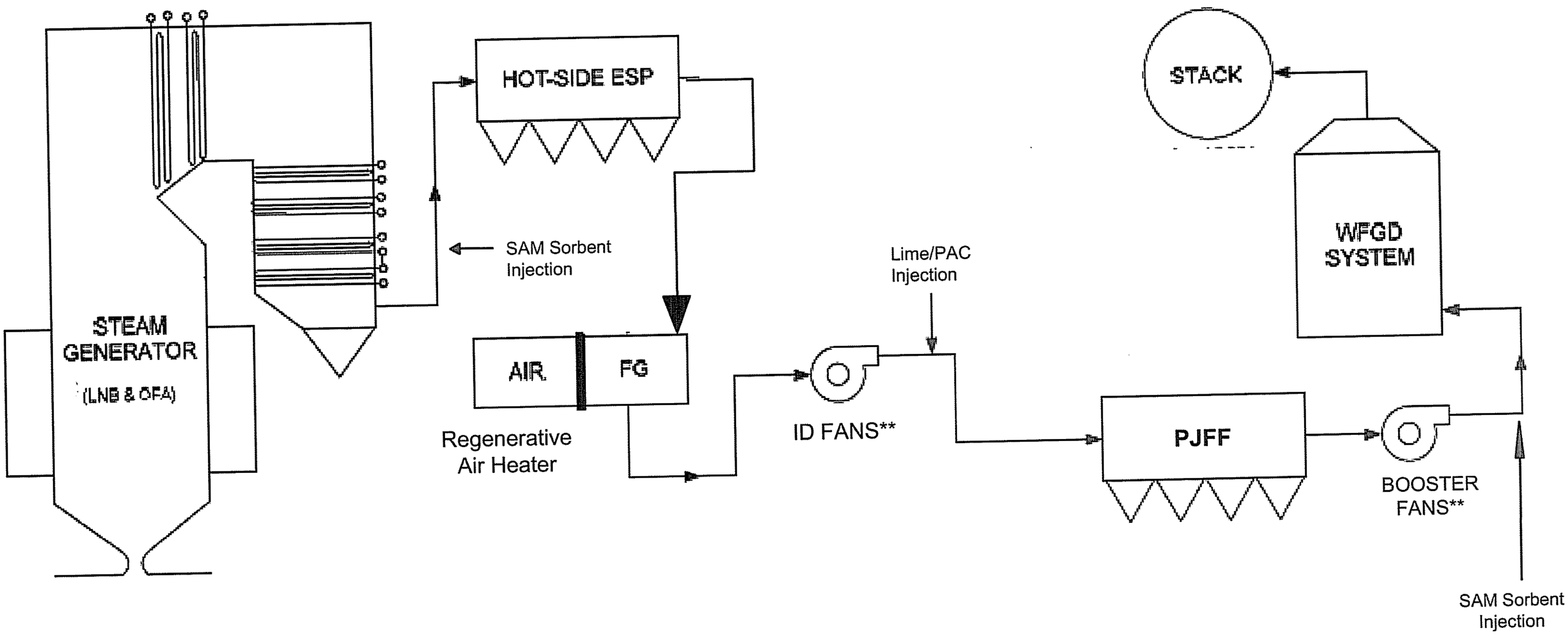


*Relocation of existing Injection Nozzles
**Replacement to new Booster Fans or larger ID Fans is yet to be determined

Black = Existing
Red = Preliminary Additions

May-11

Ghent Unit 2
AQC Process Flow Diagram

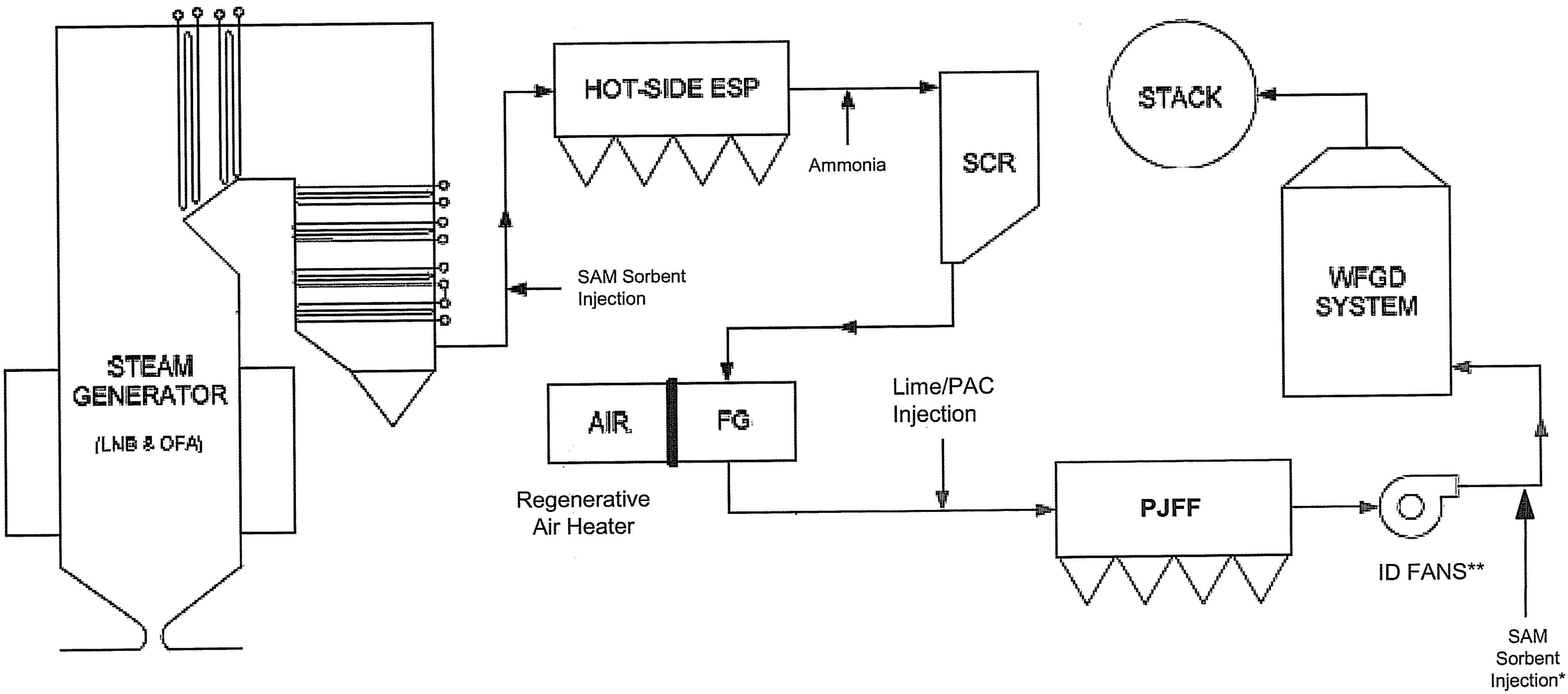


***Replacement to new Booster Fans or larger ID Fans is yet to be determined*

May-11

Black = Existing
Red = Preliminary Additions

Ghent Unit 3 and Unit 4
AQC Process Flow Diagram



**Relocation of existing Injection Nozzles*
***Replacement to new Booster Fans or larger ID Fans is yet to be determined*

Black = Existing
Red = Preliminary Additions

May-11

Exhibit JNV-4

E.W. Brown CCR Storage Evaluation
Continue Main Pond Project vs. Conversion to Landfill
September 08, 2010

Executive Summary

On June 21, 2010 the EPA issued a proposed Coal Combustion Residual (CCR) ruling that establishes federal guidelines for CCR storage. In light of the EPA's proposed CCR ruling, Project Engineering (PE) reviewed the CCR storage project (i.e., Main Ash Pond Project) at E.W. Brown (BR) that is under construction to evaluate what effects the EPA's proposed CCR rules potentially imposed on long-term wet storage of CCR at BR.

Significant work has been completed on the BR CCR Project, including detailed engineering and permitting for all phases of the project, as well as the physical work of relocating the transmission lines that cross the ash pond, ash handling upgrades and construction of the Auxiliary (Aux) Pond to elevation 880'. In addition to the completed tasks, construction of the Main Pond Starter Dike (elevation 902') is in progress but has been suspended by PE pending direction on the path forward for long-term CCR storage at BR.

As of June 2010, Phase I spend is $53.3M of the approved $73.1M sanction. Construction of Aux Pond elevation 900' (Phase II of II) is currently in progress and will proceed per the original plan or on an accelerated scheduled to support CCR storage requirements based on the path forward.

Project Engineering and the BR Station recommend the implementation of Case A to convert the Main Pond into a Landfill to meet the EPA's proposed CCP Ruling. This option has the lowest NPV and NPVRR of the Cases reviewed while maximizing the landfill footprint. Maximizing the landfill footprint also maximizes future vertical expansion opportunities and eliminates future cost and issues associated with Station operations while dewatering and closing the pond post-EPA CCR Ruling. It is important to note that both options proposed by the EPA for CCR storage are for long-term dry storage (i.e., landfill). Therefore, not converting the Main Pond Project to a dry landfill project now will not eliminate the requirement to convert all CCR storage to a dry landfill should either of the EPA proposed regulations become final.

Project Background

In 2005, PE was tasked with evaluating storage options to meet the future CCR storage requirements at BR to 2030. The evaluation process consisted of an Initial Siting study, Conceptual Design phase, and Detailed Design of the Main Pond and Aux Pond. The Initial Siting study evaluated potential storage options for BR Station and recommended an on-site storage facility as the least cost option.

The Conceptual Design was built upon the Initial Siting Study and focused on potential storage options available on-site. Options evaluated included ponds, landfills, and a combination of ponds and landfills; with the final evaluation considering three ponds and two landfill options. Pond Option #1 was a vertical upstream expansion of the existing Main Ash Pond, Pond Option #2 was a vertical upstream expansion of the existing Main Ash Pond and a new Gypsum Stack, and Pond Option #3 was a vertical upstream expansion of the existing Ash Pond and a new Bottom Ash Pond. The two landfill options were based on a common footprint; however Landfill Option #1 was based on conventional dry CCR handling and mechanical placement while Landfill Option #2 was based on wet CCR handling and dense slurry placement. Based on Net Present Value (NPV) evaluations of the (5) five options in 2005, the least-cost alternative was Pond Option #3 consisting of a new Aux Pond for bottom ash storage and the vertical upstream expansion of the existing Ash Pond for flyash and non-marketed gypsum storage. Option #3 capital costs (Phase I and II of five Phases) of $98M were approved for Environment Cost Recovery by the Kentucky Public Service Commission (KYPSC) in 2005 and again in 2009.

Upon completion of the Conceptual Design, Detailed Design of the new Aux Pond and vertical upstream expansion of the Main Pond was initiated. Detailed Design included engineering for the ponds, transmission line relocations, station mechanical upgrades, development & submittal of the Dam Safety and 404/401 permits, and several environmental studies to support the permitting process. Detailed Design for the Aux Pond was completed in 2006 followed by the Main Pond in 2007. The original design basis in 2006 was to provide 20-years (until year 2030) of CCR storage based on the following production rates:

CCR	Annual Production (yd^3)	20-Year Production (yd^3)
Gypsum	500,000	10,000,000
Fly Ash	221,000	4,420,000
Bottom Ash	55,000	1,100,000
Totals	**776,000**	**15,520,000**

Current Project Status

Phase I of Pond Option #3 CCR expansion began in 2006 with Detailed Design. The design consists of an expanded Main Ash Pond embankment, construction of an Aux Ash Pond, transmission line relocations, and ash handling upgrades. The Aux Pond is currently in operation at its initial height of elevation 880'. It provides an alternate location to treat bottom ash and fly ash in the area south of the existing Main Pond while the Main Pond Starter Dike (Starter Dike) is under construction. If the Pond Option #3 design progresses to final completion, the Main Pond will have been constructed to elevation 962' and the Aux Pond to elevation 900'.

Aux Pond

The construction sequence of the Aux Pond was designed with a two phase approach, separated by the construction duration of the Main Pond Starter Dike. Construction of the first phase, designated at Aux Pond elevation 880', commenced in October of 2006 and was placed into operation in June 2008. The second phase of construction, designated Aux Pond elevation 900', will expand the pond to the final design elevation. The second phase commenced in June 2010 and is currently planned to reach completion in mid-2013.

During the construction of Aux Pond elevation 880', the FGD facility was under construction and gypsum was not in production; therefore, the first phase of the Aux Pond was constructed of clay and rock sourced from on-site borrow. The 47-acre site was stripped and grubbed, karst features were investigated and treated, and a riser outfall structure was constructed to provide outlet control, and the facility's liner system was installed incorporating 60-mil reinforced polypropylene flexible membrane liner (FML). The FGD facility was placed into operation in June 2010, thereby adding gypsum to the by-product stream. The Aux Pond elevation 900' phase incorporates gypsum as the primary constructible fill material.

Main Pond

In June 2008, the Aux Pond was placed into operation at elevation 880'. Shortly thereafter, the Main Ash Pond was taken out of service. To date, excavation and pumping operations of the Main Pond have been performed to drain the low-lying areas allowing the existing ash surface to be stabilized and re-graded. A bi-axial geo-grid reinforced working platform and a starter dike were constructed utilizing shot rock that comprises the foundation for future phased elevation expansions. Also completed is the new riser structure, a storm water runoff system, clay borrow and bottom ash stockpiling, and liner system procurement.

In light of impending EPA regulations that were published in June of 2010, PE suspended most of the work on the Starter Dike contract in an effort to minimize construction of embankments that may not be required should the recommendation to convert the pond project to a landfill is approved. Only shared construction activities between the Starter Dike design and the projected design of a future landfill within the same footprint continue. In suspending the Starter Dike project, the liner system and embankment material can be utilized in the design of the landfill and also utilized to accelerate the construction of the Aux Pond elevation 900' Phase II, thus minimizing approximately $6.5 million of spend on construction that would be stranded.

Transmission Relocation

Early site construction included the relocation of approximately 13,000 linear feet of overhead electric transmission lines and associated poles and towers to accommodate the expansion of the Main Ash Pond and the construction of the Auxiliary Ash Pond. This phase of the construction effort was initiated in mid-2006 and was completed in 2007.

Ash Handling Upgrades

Multiple plant upgrades to the wet ash handling system resulted from the Main Pond expansion and Aux Pond construction. New higher capacity fly ash and bottom ash sluice pumps, servicing all three units, were required to overcome the added height of the Main Ash Pond embankment and the distance to the Aux Pond.

Phase I Financials

The following table depicts the Phase I expenditures to date verses the Phase I sanction amount.

Cost Through June '10 ($000)	
Engineering	$4,728
Transmission Line Relocation	$18,017
Ash Handling Upgrades	$5,947
Aux Pond 900'	$8,442
Main Pond Starter Dike	$13,202
E.ON U.S./Other	$2,947
Sub-Total	**$53,283**
ECR/Sanction Approved	$73,100
Remaining Budget	**$19,817**

EPA's Proposed CCR Ruling

As a result of the December 2008 ash pond failure at TVA's Kingston's Generating Station, the EPA issued a proposed CCR ruling on June 21, 2010 that would establish federal guidelines for CCR storage. The proposal had three options to govern the storage of CCR, Subtitle "C" – Hazardous, Subtitle "D" – Non-Hazardous, and Subtitle "D" Prime – Non-Hazardous.

Subtitle "C" – Hazardous

The Aux Pond and Main Pond at BR would not comply with the proposed ruling due to strict siting requirements and not having a composite liner. As a result the ponds would have to be closed per one of the two options below:

1. Prior to the ruling becoming effective, BR could cease operation of the ponds and close them under current KY Division of Waste Management regulations. Existing ponds would not be grandfathered in.
2. Once the ruling becomes effective, the ponds would have to stop receiving CCR within 5-years and close within 2-years thereafter. New Subtitle "C" permits would be required in addition to run-on & run-off controls, groundwater monitoring, corrective action plans, closure/post-closure care plan, and financial assurance per the ruling.

Subtitle "D" – Non-Hazardous

The Aux Pond could potentially comply with Subtitle "D" requirements but is highly unlikely as the liner consists of 18" of clay overtopped by an FML while the regulations calls for 24" of clay overtopped by an FML. Without changing our current design plans, the Main Pond at BR would not comply with the proposed ruling due to not having a composite liner and meeting strict siting requirements. As a result, the ponds would have to be closed per one of the two options below:

1. Prior to the ruling becoming effective, BR could cease operation of the ponds and close them under current KY Division of Waste Management regulations. Existing ponds would not be grandfathered in.
2. Once the ruling becomes effective, the ponds would have to stop receiving CCR within 5-years and close within 2-years thereafter. New Subtitle "D" permits would be required in addition to run-on & run-off controls, groundwater monitoring, corrective action plans, and closure/post-closure care plan per the ruling.

Subtitle "D" Prime – Non-Hazardous

Under Subtitle "D" Prime the current elevation of the Aux Pond and Main Pond at the effective date of the ruling would be grandfathered in and allowed to operate for their remaining useful life. However, any future vertical or horizontal expansion would fall under the new regulations and require a new permit, strict siting requirements, composite liner, run-on & run-off controls, groundwater monitoring, corrective action plan, and closure/post-closure care plan per the ruling. These requirements would preclude moving forward because the Main Pond (1) will not provide the required storage volume for CCR due to not being constructed to its final design elevation prior to the rules becoming effective because of both lack of gypsum or rock to construct the berm and insufficient time; and (2) the Main Pond, once placed into operation and filled with water, cannot be retrofitted with the required composite liner to comply with the strict siting requirements.

Under Subtitle "C" the EPA would effectively force the closure of all existing impoundments and eliminate impoundments for future CCR storage as a result of siting restriction, tighter water treatment standards, and cost to implement all technical requirements as set forth. Under Subtitle "D" existing impoundments that do not meet the proposed requirements would be forced to close. However, under Subtitle "D" new impoundments that are designed and constructed with a composite liner, groundwater monitoring, and in compliance with all performance standards would be allowed.

The EPA's proposed ruling will be considered in determining the path forward for the BR CCR project and its effects on the project will be discussed in later sections.

Design Basis Moving Forward

As a result of the EPA's proposed CCR Ruling, PE has reevaluated long-term CCR storage at BR as the current Main Pond design will no longer meet the 2030 storage requirement. The analyses are based on an assumption that the proposed ruling becomes effective on January 2012. The January 2012 effective date was based on the proposed ruling being approved in 2010, and accounted for one year of litigation before the ruling became effective. The 3 options available are summarized below:

- **Base Case** – Continue with construction of the Aux Pond to elevation 900' and the Main Pond to 962' per the original design.
- **Case A** – Stop construction of the Main Pond Starter Dike immediately and convert the Main Pond into a landfill prior to the effective date of the CCR Ruling and prior to placing wet CCR in the Main Pond. Complete construction of the Aux Pond 900' project utilizing rock in lieu of gypsum to accelerate construction completion prior to the rules becoming effective. The Aux Pond will eventually be closed per the new regulations once the landfill is placed into service.
- **Case B** – Continue construction of the Main Pond Starter Dike and Aux Pond 900' per the original design. Once the CCR Ruling becomes effective, take the Main Pond out of service, close and cap it per the new regulations, and then construct a landfill similar to Case A on top of the newly constructed Main Pond Starter Dike. As with Case A, once the landfill is placed into service the Aux Pond will be closed per the regulations.
- **Case C** – Modify the design of the Main Pond and install a composite liner per Subtitle "D" requirements. Complete the Aux Pond 900' project as originally designed.

Each case was evaluated based on the most recent forecast of CCR production rates as provided by Generation Planning. In the third quarter of 2009, Generation Planning issued updated CCR production rates based on the projected 2010 MTP generation plan. The CCR production rates for BR modeled in 2009 were significantly lower than the original production rates utilized in 2005. This is attributed to a significant reduction in the station's capacity factor from 77 percent to 54 percent due to shifting generation to other stations. Comparison of the average annual CCR production rates are provided below:

CCP	**Average Annual Production Rates (yd^3)**			
	2005 Design Basis	**2010 MTP**	**Δ**	**% Reduction**
Bottom Ash	55,000	35,879	(19,121)	35%
Fly Ash	221,000	143,516	(77,484)	35%
Gypsum	500,000	290,000	(210,000)	42%
Totals	**776,000**	**469,395**	**(306,605)**	**47%**

The required CCR storage capacity till 2030 using the 2010 MTP production rates is now 7M yd^3 based on an in-service date of January 2014. If utilizing the original 2005 design volume of

15.5M yd^3 the storage, the facility would have a design life of approximately 38-years (2048), well beyond BR's needs.

Moving forward, the CCR storage facility at BR for both viable Cases A and B will provide a minimum storage capacity of 7M yd^3 and will allow for future expansion if necessary. As described below, the Base Case of continuing to construct the Main Pond and utilize it until 2030 will not be allowed under either scenario in the proposed regulations. In other words, the CCR landfill for both Cases will be designed and permitted with the maximum footprint available and the height of the facility will be adjusted to meet potential changing capacity requirements.

Base Case

The Base Case is the plan currently being implemented and is in-line with the approved ECR & 2006-2010 MTP/LTP plans. Phase I included the design & permitting of the Aux Pond and Main Pond, relocation of the transmission lines, wet ash handling upgrades, Aux Pond 880' construction, and Main Pond Starter Dike construction. All items except the Main Pond Starter Dike construction (in suspension) have been completed. Phase II includes Aux Pond 900' (its final elevation) and Main Pond 912' construction utilizing gypsum. Under the EPA's proposed CCR Ruling, neither pond will meet either of the proposed requirements and will be required to close per the timeframe outlined in the ruling. As a result, moving forward with the Base Case based on the current plan and liner design will not provide BR the required storage through 2030, even at the lower 2009 model production rates.

Base Case Design Issues

The EPA has proposed three options to manage CCR. If the EPA moves forward with Subtitle "C", this option will effectively eliminate all wet CCR storage and would require all existing ponds to retroactively meet the design criteria or cease operation and close per the requirements set forth under Subtitle "C". The Main Pond at BR would not comply with the proposed ruling due to siting requirements, land disposal restrictions (waste treatment), and not having a composite liner & leachate collection system along with other minor issues. A composite liner and leachate collection system could be installed; however the siting requirements and land disposal restriction would remain an issue.

Under Subtitle "D", the EPA is more open to wet storage of CCR. However, several issues remain such as siting requirements (karst, seismic, proximity to wetland & adjacent property owners, etc), composite liner & leachate collection system, and requiring ponds to retroactively meet the design criteria or cease operation and close per the requirements set forth under Subtitle "D". Prior to the effective date of the EPA's ruling, the Main Pond could be constructed to its ultimate elevation of 928' using rock (if a source of sufficient rock quantity can be found) in-lieu of gypsum and include a composite liner with leachate collection. However, the Main Pond would still be subject to the siting requirements under Subtitle "D". By using rock in-lieu of gypsum, the design life of the pond will be reduced by 8 years as the gypsum eventually produced that would have been used to construct the dike would instead be stored in the pond. To complete construction prior to the effective date, embankment must be placed at 12,000 yd^3 per day when normal average construction is

3,000-5,000 yd^3 per day. In addition, close proximity land would have to be purchased to supply the quantity of clay required to construct the composite liner and to supply the rock necessary to construct the embankments. Compliant rock and clay currently sourced from the Houp Property is becoming limited. Based on production rates from the existing quarry, an additional 200 acres would be required to supply the 2.2M yd^3 of rock needed to complete the Aux Pond to an elevation of 900' and the Main Pond to an elevation of 928'. The purchase of 200 acres for additional borrow sources would add $2.0M (2010 dollars) to the project based on cost data gathered on the Ghent Landfill Project. Assuming the new quarry is located less than 5 miles from the plant and utilizing 40-ton articulated trucks, the additional hauling cost would be approximately $10.25M (2010 dollars) based on 2010 RS Means estimating manuals. These additional costs have not been included in the NPV or PVRR analysis.

Construction of the Main Pond could continue by modifying its design to comply with the proposed technical requirements at a significant cost increase and risk to the company. The technical requirements as proposed could change prior to the final ruling and the pond would no longer be in compliance. The EPA is trying to eliminate ponds and move towards dry landfills; therefore, constructing a new pond for long term CCR storage carries significant risk.

Under Subtitle "D" Prime the current elevation of the Main Pond, at the effective date of the ruling, would be grandfathered in and allowed to operate for the remainder of its useful life. However, any future vertical or horizontal expansion would fall under the new regulations and require a new permit, compliance with strict siting requirements, composite liner, run-on & run-off controls, groundwater monitoring, corrective action plan, and closure/post-closure care plan per the ruling. Prior to the effective date of the EPA's ruling the Main Pond could be constructed to its ultimate elevation of 928' as described above. However, there is significant risk as Subtitle "D" Prime is the least likely alternative to be approved as the EPA is trying to eliminate ponds and move towards dry landfills.

Based on the revised 2010 MTP CCR production rates requiring the reduced storage of 7M yd^3, the Main Pond's maximum elevation has been lowered from 962' to 928'. Moving forward, cost data provided for the Base Case will be based on a final elevation of 928'. The following table reflects the NPV, PVRR, and capital cost cash flows for the Base Case option as currently included in the 2011 MTP/LTP draft of July, 2010.

Base Case Capital Cost ($000) for 7M yd^3											
2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**NPV**	**PVRR**	**Total Project**
$19,300	$6,700	$4,153	$6,365	$3,424	$8,951	$2,637	$2,699	$3,813	$103,720	$127,799	$121,687

Case A

Case A consists of immediately terminating construction of the Main Pond Starter Dike (excluding site close out activities such as dust control and reclamation), accelerating the construction of the Aux Pond utilizing rock already blasted that has been recently placed in the Main Pond Starter Dike (thus reducing stranded investments), continued ash grading, Main Pond cap/closure, Landfill engineering and permitting, converting all station ash handling systems from wet to dry, and constructing the initial phase of a Landfill. Based on recent projects, the anticipated duration to perform these activities is 3.5 years with an in-service date of January 2014.

Design and construction of the Landfill would begin prior to final approval of the EPA's proposed CCR Ruling; however the Landfill liner requirements for both Subtitle "D" Non-Hazardous and "C" Hazardous options are the same and will become the basis of design. By terminating construction of the Main Pond Starter Dike, material already purchased and/or stockpiled, such as FML, Filter Fabric, Clay, Rock, and Bottom Ash, will be utilized in the construction of the Landfill thereby minimizing the cost impacts from the approximately $6.5 million stranded cost for the materials purchased or quarried. Additionally, by utilizing rock already blasted and placed in the Main Pond Starter Dike, the footprint of the landfill will be optimized to approximately 100 acres thereby reducing the final height of the landfill and maximizing the future vertical expansion opportunities up to approximately 18M yd^3.

All Plant effluents and CCR will continue to be directed to the Aux Pond during the design, permitting, and construction of the landfill for approximately 3.5 years in order to keep BR in operation. Based on a recent bathymetric survey conducted by MACTEC, and utilizing the 2010 CCR Production Rates, the Aux Pond has enough remaining capacity to store all the CCR generated through January 2015. This is a conservative estimate and provides one year of project float. The following table reflects the NPV, PVRR, and capital cost cash flows for Case A as reflected in the notes to the 2011 MTP/LTP as Landfill Option #1.

Case A Capital Cost ($000)											
2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**NPV**	**PVRR**	**Total Project**
$9,051	$14,262	$26,722	$24,064	$0	$0	$0	$0	$9,321	$126,322	$181,791	$154,939

Case B

Case B consists of completing the Main Pond Starter Dike and Aux Pond 900' projects as designed and permitted prior to final approval of the EPA's proposed CCR Ruling. Upon approval of the EPA's proposed CCR Ruling, the Main Pond would be taken out of service; the Main Pond would then be dewatered, followed by ash grading, Main Pond cap/closure, Landfill engineering, permitting, wet to dry ash handling conversion, and the initial phase of construction of the Landfill. Based on recent projects, the anticipated duration to perform these activities is 5.5 years with an in-service date of January 2016.

If the construction of the Main Pond Starter Dike were to continue to completion and the EPA's proposed ruling was approved, material already purchased and/or stockpiled such as FML, Filter Fabric, Clay, Rock, and Bottom Ash *cannot* be salvaged or otherwise made available for the construction of the Landfill resulting in the need to purchase additional land for approximately $2M to develop new borrow sources and liner material at future market values. Design and construction of a landfill would begin after final approval of the EPA's proposed CCR Ruling which would be the basis of design. By continuing with the construction of the Main Pond Starter Dike, the footprint of the landfill would be approximately 80 acres, some 20 acres less than Case A, thus reducing the potential for future vertical expansion, approximate maximum capacity 13.25M yd^3. Case B also would involve having to develop an operation plan for the Brown Station that would enable it to remain in operation while the recently constructed Main Pond was taken back out of service and dewatered to allow construction of the Landfill. **These operational costs are not included in the total project cost shown in the table below as they are difficult to estimate at the time of preparing this paper; however, they are expected to be significant**.

During the design and permitting of the landfill, both the Aux Pond and Main Pond will be used to store CCR material. During construction, a duration of approximately 2 years, all CCR generated will be stored in the existing Aux Pond. Based on a recent bathymetric survey conducted by MACTEC, and utilizing the 2010 CCR Production Rates, the Aux Pond has enough remaining capacity to store all the CCR generated for 2 years starting January 2014. The following table reflects the NPV, PVRR, and capital cost cash flows for Case A as reflected in the notes to the 2011 MTP/LTP as Landfill Option #2.

Case B Capital Cost ($000)											
2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**NPV**	**PVRR**	**Total Project**
$19,350	$2,907	$3,605	$10,786	$31,135	$31,387	$0	$0	$0	$143,980	$204,633	$193,567

NOTE: Case B values do not include the estimated $2.0M for land purchase for additional clay borrow source.

Case C

Case C consisted of completing the Aux Pond 900' project as designed and modifies the Main Pond Starter Dike to include a composite liner system. With the addition of 24" of clay the Main Pond could comply with Subtitle "D"; however, the Main Pond would not comply with Subtitle "C" and does not comply with the EPA intent to eliminate ponds for storage. Case C was eliminated because (1) it is not possible to source clay and rock from the existing station property in the quantities required; (2) it is not economically feasible to source clay from the surrounding area and the time required to locate and acquire a farm with sufficient quantities within the timeframe required is deemed marginal at best; and (3) to design and construct the composite liner will only allow compliance with subtitle "D" and not "C". Based on this no further consideration was given to Case C.

Schedule Impacts

If the decision is made to convert the Main Pond into a Landfill there are several items that will impact the schedule. They include engineering/design, permitting, a new or updated ECR/CPCN filing, and initial landfill construction. Based on experience from previous projects the engineering/design will take approximately 3-4-months and will include development of the landfill drawings, specifications, stability analysis, groundwater monitoring plan, and permit application.

Permitting will take approximately 18-months and should only include the KY Division of Waste Management permit as the remaining permits were obtained during the original Main

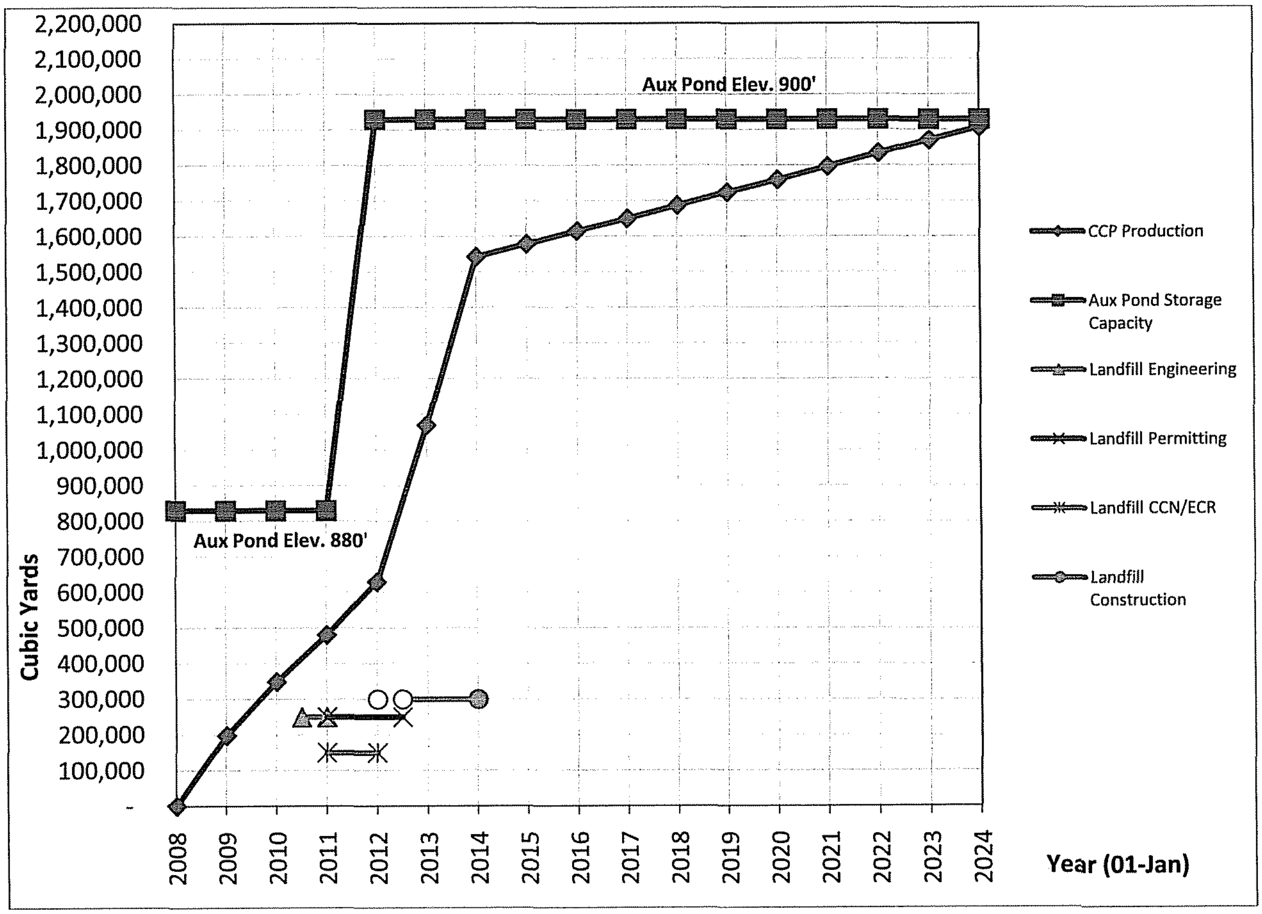
Pond project permitting. The updated or new ECR/CPCN filing will take approximately 6-months and would be submitted in parallel with the engineering/design and permitting process.

The initial landfill construction timeline will be dependent on the chosen option, but will take between 18-24 months to complete. Based on the above, PE performed an analysis to ensure the Aux Pond had enough storage capacity remaining to support the conversion of the Main Pond into a Landfill. Results of the storage analysis are provided below and indicate that the Aux Pond has enough capacity to support either Case A or Case B.

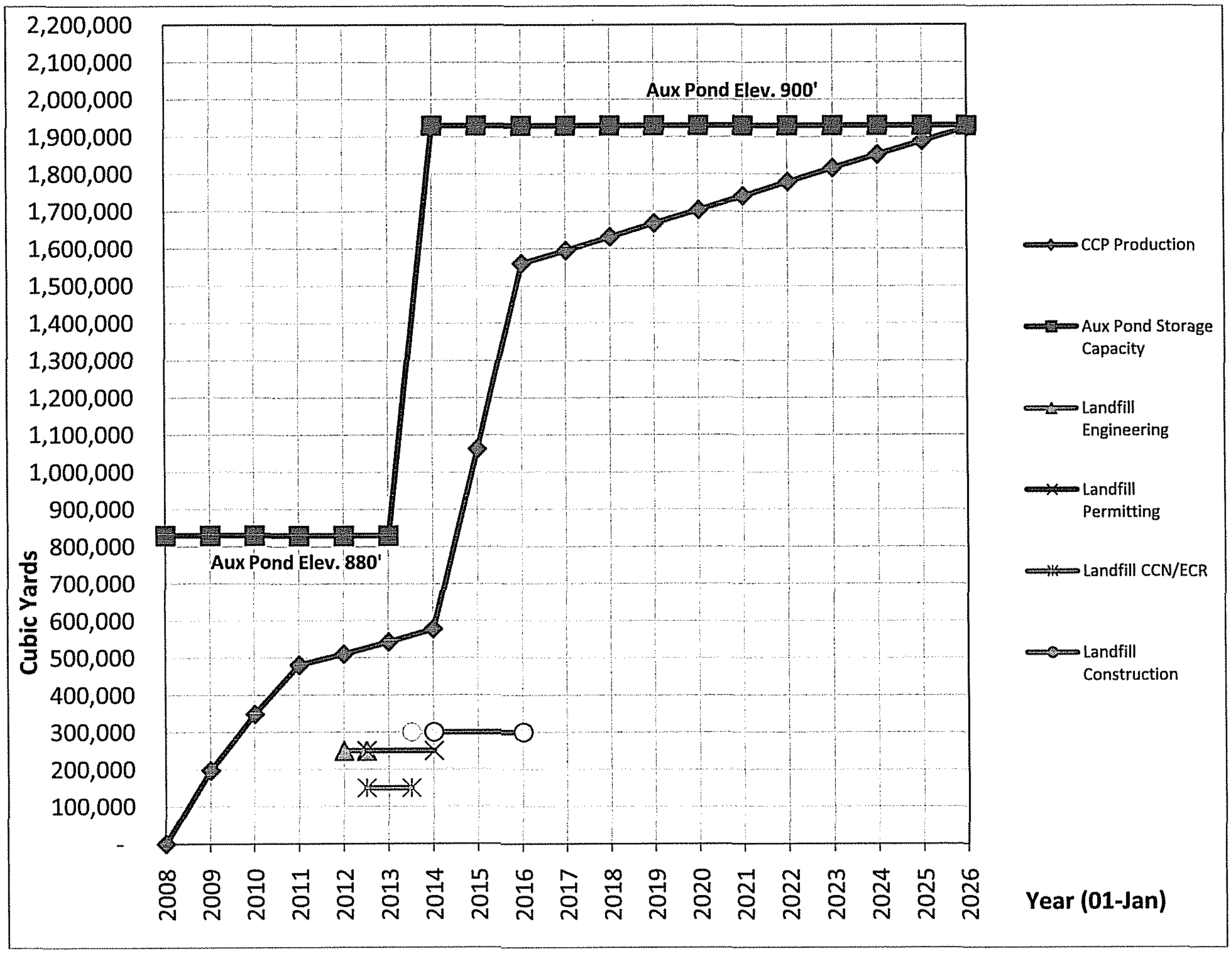
A summary of the schedule is shown below.

Project Timeline		
Task	**Date**	**Duration**
Informal Meeting w/the PSC	October 2010	1 Day
Engineering	September 2010	3-4 Months
File Permits	December 2010	18 Months
CPCN/ECR Filing	December 2010	6 Months
Construction	May 2012	18 Months

Aux Pond Stage Storage Graph (Case A) – Stop Main Pond Starter Dike & Accelerate Aux Pond 900' Construction



Aux Pond Stage Storage Graph (Case B) – Complete Main Pond Starter Dike & Aux Pond 900' per Original Schedule



Financials

Considering the factors referenced above, PE with the assistance of MACTEC, developed capital cost estimates for Case A and B which were based on a horizontal expansion of the landfill. Additional engineering is required to determine if a horizontal or vertical expansion approach is the best alternative. Timing of cash flows would be affected if a vertical expansion approach is chosen. The ECR approved cost estimate is the basis for the 2011 MTP/LTP and is provided for reference only. The Base Case is a modification of the ECR approved option which provides 7M yd^3 of storage and is no longer a viable long term solution for CCR storage as the current design of the Main Pond will not comply with the EPA's proposed CCR Ruling. *Case A or B are the only long term storage solutions.*

Cost Estimate Comparison											
Option	**Life**	**Capacity**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**NPV**	**PVRR**	**Total Project**
ECR Approved	2054	15.5M yd^3	\$25,233	\$10,220	\$8,777	\$4,865	\$5,463	\$6,945	\$143,394	\$158,684	\$200,132
Base Case	2030	7M yd^3	\$19,300	\$6,700	\$4,153	\$6,365	\$3,424	\$8,951	\$103,720	\$127,799	\$121,687
Case A	2030	7M yd^3	\$9,051	\$14,262	\$26,722	\$24,064	\$0	\$0	\$126,322	\$181,791	\$154,939
Case B	2030	7M yd^3	\$19,350	\$2,907	\$3,605	\$10,786	\$31,135	\$31,387	\$143,980	\$204,633	\$193,567

NOTE: Case B values do not include the estimated \$2.0M for land purchase for additional clay borrow source.

Recommendation

Project Engineering and the Brown Station recommend the immediate implementation of Case A to convert the Main Pond into a Landfill to meet the EPA's proposed CCP Ruling. This option has the lowest NPV & PVRR, is the least cost, maximizes the landfill footprint, maximizes future vertical expansion opportunities to accommodate changes in production, and eliminates the difficult and costly issues associated with maintaining station operations while dewatering and closing the pond post EPA CCR Ruling while the landfill is being constructed.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF KENTUCKY UTILITIES COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	))))))	CASE NO. 2011-00161

DIRECT TESTIMONY OF
GARY H. REVLETT
DIRECTOR, ENVIRONMENTAL AFFAIRS
LG&E AND KU SERVICES COMPANY

Filed: June 1, 2011

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

A. My name is Gary H. Revlett. I am the Director of Environmental Affairs for LG&E and KU Services Company, which provides services to Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively "the Companies"). My business address is 220 West Main Street, Louisville, Kentucky, 40202. A complete statement of my education and work experience is attached to this testimony as Appendix A.

Q. Have you previously testified before this Commission?

A. Yes, I testified before the Commission during the proceedings in the Companies' 2006 Environmental Compliance Plans (Case Nos. 2006-00206 (KU) and 2006-00208 (LG&E)). I have also sponsored responses to data requests in a number of proceedings before the Commission, including the Companies' 2009 Environmental Compliance Plan proceedings (Case No. 2009-00197 (KU) and 2009-00198 (LG&E)).

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit GHR-1	U.S. Environmental Protection Agency Notice of Violation for the Ghent Generating Station (2007)
Exhibit GHR-2	U.S. Environmental Protection Agency Notice of Violation for the Ghent Generating Station (2009)
Exhibit GHR-3	Kentucky Utilities Consent Decree with U.S. EPA (March 2009)
Exhibit GHR-4	E.W. Brown Generating Station Title V Air Permit

When KU files its applications with the Kentucky Energy and Environment Cabinet, Division for Air Quality ("KYDAQ") for the necessary changes to the Title V operating permits for the E.W. Brown and Ghent Generating Stations, which it anticipates doing by this fall, it will file copies of the applications in the record of this proceeding. Likewise, KU anticipates that it will file an application with the Kentucky Division of Waste Management ("KYDWM") to build a landfill at the E.W. Brown Generating Station by this fall, and will file a copy of the application with the Commission at that time.

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 KU's 2011 Environmental Compliance Plan ("2011 Plan") and demonstrate how those facilities will allow KU to comply with these environmental regulations. (A copy of the 2011 Plan is presented in Exhibit JNV-1 to the testimony of John N. Voyles.) The projects identified in the 2011 Plan are necessary for KU's compliance with the requirements of the Clean Air Act as amended ("CAAA"), the proposed Clean Air Transport Rule ("CATR"), the proposed national emission standards for hazardous air pollutants ("HAPs Rule"), the federal Resource Conservation and Recovery Act ("RCRA"), and other environmental regulations that apply to KU's facilities used for the production of electricity from coal.

Q. Please describe environmental regulation as it exists today.

A. Environmental compliance is and always has been 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, and all subsequent amendments to and revisions of these and other environmental laws and regulations have significantly increased KU's 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 especially, but also of the storage of coal combustion residuals ("CCRs"), 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 KU's 2011 Plan.

Q. What environmental laws and regulations are applicable to the control of air emissions from coal-fired generating stations?

A. Under the CAAA, KU 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 process. All of the KU 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 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 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 proposed CCR regulation, CATR, and HAPs Rule, as well as the impacts of EPA enforcement actions, on KU's E.W. Brown and Ghent Generating Stations.

Q. Does KU's 2011 Plan list the environmental permits and regulations that are applicable to KU?

A. Yes. My testimony describes the environmental regulations and permit requirements applicable to KU, and Column 5 of KU's 2011 Plan (Exhibit JNV-1) summarizes these regulations and requirements. The pollution control facilities listed as amended Project 29 and Projects 34-35 of the 2011 Plan will enable KU to continue to fulfill its environmental compliance obligations. The environmental permits applicable to the proposed projects are set out in Column 6 of KU's 2011 Plan.

Q. What are the environmental regulations driving KU's 2011 Plan?

A. There are two proposed EPA air-quality regulations driving the vast majority of what KU proposes in its 2011 Plan: CATR and the HAPs Rule. Under the authority of (and as required by) CAAA, the EPA has issued these proposed and soon-to-be-final regulations. It is important to note that both are successors to earlier rules: the proposed CATR 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 proposed HAPs 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).

In addition to those regulations, the EPA's proposed CCR regulation provides the impetus for KU's proposal to amend Project 29 by converting the Brown Main Ash Pond to a dry-storage facility for CCR. The proposed CCR regulation is unusual in that it is a bifurcated proposed rulemaking; in essence, EPA has proposed two rules for consideration with the expectation that one of them will become the final rule. Whichever proposed rule becomes final, it will be the first time the EPA will have regulated CCR storage under RCRA.

Finally, the sulfuric acid mist ("SAM") mitigation facilities KU proposes to install at Brown and Ghent are due to enforcement actions EPA has taken against KU under its prevention of significant deterioration ("PSD") rules.

<u>The Clean Air Interstate Rule and the Clean Air Transport Rule</u>

Q. Please describe CAIR and CATR, and their relationship to each other.

A. Section 110 of the CAAA permits 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 (and still requires) 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

[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[.]").

(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.

But 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 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; however, the court's later order still required EPA to promulgate a regulation to replace CAIR.[3]

On July 6, 2010, pursuant to the court's orders, EPA delivered its proposed replacement for, and enhancement to, CAIR in the form of the notice of proposed rulemaking ("NOPR") for the Clean Air Transport Rule, CATR.[4] The new rule is designed to achieve emissions reductions beyond those originally required by CAIR through additional emissions reductions from power plants beginning in 2012, with additional reductions to be in place for 2014 and following years. CATR creates more stringent state-specific allowance budgets (or "caps") for SO_2 and NO_X, and would allow for only limited interstate allowance trading to ensure that individual states actually have to make the reductions EPA desires (though unlimited intrastate trading would be permitted).[5] This allowance regime, which is separate and different

[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 CATR NOPR was published in the Federal Register on August 2, 2010 (Vol. 75, No. 147, Page 45210).

[5] This allowance trading and emission restriction regime is EPA's "preferred" approach. The NOPR provides two other alternatives: (1) a complete ban on interstate allowance trading; and (2) direct restrictions on generating plant emissions with some emissions averaging permitted.

from the existing allowance programs under the CAAA, will drive up the cost of allowances and necessitate reducing KU's SO_2 and NO_X emissions over time.

Q. What steps does KU propose to take to comply with CATR?

A. As discussed in greater detail in Mr. Voyles's testimony, Project 35 of KU's 2011 Plan contains elements to reduce NO_X emissions. Specifically, KU proposes to modify facilities at Ghent Units 1, 3, and 4 to expand the generating-unit-operating range at which the units' Selective Catalytic Reduction facilities ("SCRs") can remain in service to effectively reduce NO_X emissions. As more fully described in Mr. Voyles's testimony and the testimony of Charles R. Schram, these SCR-related project elements are the most cost-effective way for KU to comply with CATR.

Q. Why is KU proposing to take steps to comply with an environmental regulation that is not yet final?

A. Although CATR is not yet final, EPA has announced that it will be finalized by July.[6] Moreover, there is no doubt about EPA's commitment to ensure that interstate emissions are reduced to at least the levels set out in CATR. The preamble to the CATR NOPR states:

> EPA is proposing to limit these emissions through Federal Implementation Plans (FIPs) that regulate electric generating units (Electric generating units) in the 32 states. This action will substantially reduce the impact of transported emissions on downwind states. In conjunction with other federal and state actions, it helps assure that all but a handful of areas in the eastern part of the country will be in compliance with the current ozone and PM2.5 NAAQS by 2014 or earlier. **<u>To the extent the proposed FIPs do not fully address all significant</u>**

[6] *Id.* at 45273 ("There are approximately 30 months between mid-2011 (when the Agency anticipates finalizing this rule) and January 2014 (the proposed Phase 2 compliance deadline).").

<u>transport, EPA is committed to assuring that any additional reductions needed are addressed quickly</u>."[7]

Moreover, EPA has already stated it plans to issue a sequel to CATR (CATR II) after it revises the ground-level ozone and $PM_{2.5}$ NAAQS. CATR II will likely result in further NO_X and SO_2 emissions reductions.[8]

In short, there is every reason to believe that CATR 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 the CATR NOPR will go into effect.

<u>The Clean Air Mercury Rule and the National Emission Standards for Hazardous Air Pollutants</u>

Q. Please describe CAMR and the HAPs Rule, and their relationship to each other.

A. To understand CAMR and the HAPs Rule, it is important to understand the 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. When that history is understood, it is clear that the proposed HAPs Rule is nearly certain to become final substantially in its present form, and that EPA must regulate mercury and other HAPs emissions from power plants.

In 1970, Congress included Section 112 in the Clean Air Act, which required EPA to list HAPs and determine which HAPs emission sources should be regulated. EPA evidently moved too slowly to list pollutants and emissions sources to achieve Congress's objectives: 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

[7] *Id.* at 45210 (emphasis added).
[8] *See* http://www.epa.gov/glo/actions.html#dec10s.

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 required (and still requires) EPA to regulate electric generating units with respect to HAPs—including mercury—if the EPA Administrator determined it was appropriate to do so after reviewing the required study: "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."[9]

The EPA completed the required study in 1998, which found "a plausible link between anthropogenic releases of mercury from industrial and combustion sources in the United States and methylmercury in fish" and that "mercury emissions from [electric generating units] may add to the existing environmental burden."[10] 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.[11]

On January 30, 2004, EPA proposed two alternatives to regulate electric generating unit emissions.[12] The first alternative was to regulate electric generating units under Section 112 by issuing Maximum Achievable Control Technology

[9] CAAA § 112(n)(1)(A) (emphasis added).

[10] 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).

[11] *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).

[12] *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).

("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 ....")[13] 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).

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

[13] CAAA § 112(d)(3)(A) (emphasis added).

like KU's, CAMR's mercury emission limit for new units was 21 lbs/TWh.[14]

It was CAMR's new-source requirement that led KYDAQ to place an even-stricter mercury emission limit of 13 lbs/TWh on the Companies' newest coal-fired generating unit, Trimble County Unit 2 ("TC2"). To meet that requirement, KU and LG&E installed, with this Commission's approval,[15] the same kind of mercury-emission control system on TC2 that KU now proposes to install on its Brown and Ghent units (i.e., baghouses and powdered activated carbon ("PAC") injection systems as components of overall Particulate Matter Control Systems). (TC2's actual mercury emissions have been lower than the current 13 lbs/TWh limit and will comply with the HAPs Rule without modification to the unit's existing environmental control equipment.)

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.[16] 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

[14] *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 21×10^{-6} pound per megawatt hour (lb/MWh) or 0.021 lb/gigawatt-hour (GWh) on an output basis.").

[15] *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 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).

[16] *See New Jersey v. EPA*, 517 F.3d 574 (D.C. Cir. 2008).

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 March 16, 2011, issued the HAPs Rule. For existing coal-fired units designed for coal with an energy content of at least 8,300 Btu/lb (which includes all of KU's coal-fired units), the proposed HAPs Rule's mercury emission limit was 1.0 lbs/TBtu or 8 lbs./TWh. However in May 2011, EPA revised the proposed existing source mercury MACT limit to 1.2 lbs/TBtu (13 lbs/TWh).[17] This limit is over 35% more restrictive than CAMR's requirement and equals the Title V permit requirement for our new TC2, which is an extremely low emitter.

Q. What other emissions does the HAPs Rule address?

A. As I mentioned at the beginning of my testimony, the HAPs Rule regulates emissions of particulate matter (as a surrogate for hazardous non-mercury metals), and hydrogen chloride (HCl). The HAPs Rule's emission limit for total particulate matter from existing electric generating units is 0.030 lb/MMBtu. For HCl, the HAPs Rule's emission limit from existing electric generating units is 0.0020 lb per MMBtu; however, the HAPs Rule allows SO_2 to be measured as a surrogate for directly

[17] On May 18, 2011, EPA issued a letter acknowledging that the proposed existing coal-fired unit mercury emission limit was incorrect due to computational errors, and that a value of 1.2 lbs./TWh is correct. It still represents a "90 percent reduction from the mercury in the coal used by power plants."

measuring HCl, and this is the measure KU will use. The SO_2 limit as a surrogate for HCl under the HAPs Rule is 0.20 lb per MMBtu.

Q. What steps does KU propose to take to comply with the HAPs Rule?

A. KU is currently in compliance with the HAPs Rule's SO_2 emission limit as a HCl surrogate for all units controlled with a FGD, so there are no measures in the 2011 Plan to meet that requirement. Concerning the particulate matter and mercury emissions limits imposed by the HAPs Rule, KU proposes to install Particulate Matter Control Systems to serve all of its Brown and Ghent units, as Mr. Voyles discusses in greater detail in his testimony. Each Particulate Matter Control System comprises a pulse-jet fabric filter ("baghouse") to capture particulate matter, a Powdered Activated Carbon ("PAC") injection system to capture mercury, and a lime injection system to protect the baghouses from the corrosive effects of sulfuric acid mist ("SAM"). These facilities are contained in Projects 34 and 35 of the 2011 Plan.

As more fully described in Mr. Voyles's and Mr. Schram's testimony, these project elements are the most cost-effective way for KU to comply with the HAPs Rule.

Q. Why is KU proposing to take steps to comply with an environmental regulation that is not yet final?

A. Although the HAPs Rule is not yet final, EPA must issue the final rule by November 16, 2011 pursuant to a consent decree between the EPA and the U.S. Department of Justice, so the rule will be final before the Commission must issue a final order in this proceeding.[18]

[18] *Id.* at 45273 ("There are approximately 30 months between mid-2011 (when the Agency anticipates finalizing this rule) and January 2014 (the proposed Phase 2 compliance deadline).").

Moreover, as I described in detail above, the history of EPA's (and KYDAQ's) regulation of electric generating unit emissions under the CAAA has been one of unrelenting tightening of restrictions, not loosening. To the best of my knowledge, there are no regulatory infirmities imperiling the HAPs Rule. In short, just as is true with CATR, there is no reason to believe that the final HAPs Rule will contain HAP emission limits significantly different from those in the proposed rule.

And as Mr. Voyles discusses in his testimony, KU simply cannot prudently wait for the rule to become final before it acts to comply. The CAAA requires compliance with regulations issued under Section 112(d), such as the HAPs Rule, within three years of issuance of a final rule.[19] States that have been given primacy to implement such regulations (including Kentucky) may extend that compliance deadline by one year.[20] But barring presidential intervention,[21] a maximum of four years is all the time utilities will have to comply with the HAPs Rule. And given that the entire coal-fired industry must comply with the HAPs Rule, four years is a very short time to build all the control facilities the industry will need. Also, delaying obtaining firm contracts to build such facilities could result in having to pay higher prices for labor and materials as those resources become increasingly demanded in the scramble to comply. For that reason, it is prudent for KU to begin to act now to ensure timely compliance.

Finally, the EPA was clear in the HAPs Rule NOPR that it expects utilities and other affected entities to begin acting before the rule becomes final to ensure timely compliance:

[19] 42 U.S.C. § 7412(i)(3)(A).
[20] 42 U.S.C. § 7412(i)(3)(B).
[21] 42 U.S.C. § 7412(i)(4).

> EPA expects that sources will begin promptly, ***based upon this proposed rule***, to evaluate, select, and plan to implement, source-specific compliance options. ... Starting assessments early and considering the full range of options is prudent because it will help ensure that the requirements of this proposed rule are met as economically as possible and that power companies are able to provide reliable electric power.[22]

The agency also advised affected entities to work with their environmental regulators now to ensure that needed one-year extensions to the normal three-year CAAA compliance requirement will be granted:

> Environmental regulators should work with their affected sources early to understand their compliance choices. In this way, those regulators will be able to accurately access when use of the 1-year compliance extension is appropriate. By working with regulators early, affected sources will be in a position to have assurance that the 1-year extension will be granted in those situations where it is appropriate.[23]

KU has been, and will continue to be, in contact with KYDAQ concerning these compliance issues. Indeed, I will contact KYDAQ and KYDWM to provide their staffs copies of this application immediately after KU files it with the Commission. But it is also prudent for KU to come to the Commission now to seek approval for the facilities it will need to comply with these rules.

<u>The Coal Combustion Residuals Regulation</u>

Q. Please describe the EPA's proposed CCR regulation.

A. On June 21, 2010, EPA issued a NOPR that proposed different versions of a rule under RCRA to regulate CCR (the first time EPA has proposed such a regulation under RCRA). As the NOPR states multiple times, EPA is concerned about the

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[22] *National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, 76 Fed. Reg. 24,976, 25,056 (May 3, 2011).
[23] *Id.*

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 is bifurcated, but one proposed option has a sub-option attached to it. EPA's preferred option 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 ...."[24] 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 main option in the CCR NOPR is to classify CCR as a non-hazardous waste under RCRA Subtitle D. This approach would not empower EPA to

[24] *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).

have "cradle-to-grave" regulatory oversight of CCRs, but rather would permit it to set minimum storage standards for states to enforce. Among those requirements are 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.

Q. Does the Kentucky Division of Waste Management have a view on the most appropriate method of compliance?

A. Yes. KYDWM management personnel have told the Companies that, though there is no current regulation to force construction of a landfill as the primary means of handling, storage, and disposal of CCRs, landfills are KYDWM's preferred option due to their inherent stability. These personnel have also told the Companies that EPA's desired landfill requirements are consistent between the proposed regulatory approaches, and are generally in line with current industry practice. For these reasons, KYDWM personnel have informed the Companies that landfill permitting will be possible while EPA continues to consider which regulatory approach to take in its final CCR regulation.

Q. What steps does KU propose to take to comply with the CCR NOPR?

A. As Mr. Voyles describes in his testimony (supported by the cost-benefit analysis described in Mr. Schram's testimony), the Brown Main Ash Pond is in the midst of a Commission-approved expansion. But the likelihood that EPA will soon issue a final CCR storage rule that will ultimately require the closure of such surface impoundments or make it more cost-effective to have landfills instead changes the cost-benefit analysis concerning going forward with the full pond expansion. Instead, the more cost-effective approach in the face of the CCR NOPR is to convert the pond to a CCR landfill, which is the proposed amendment to Project 29.

Q. Why is KU proposing to take steps to comply with an environmental regulation that is not yet final?

A. It is important to understand how significant the CCR NOPR is. As I mentioned above, this is the first time EPA has proposed to regulate CCR under RCRA. And though the NOPR contains multiple possible final rules, it was only at the last minute that EPA added options to the NOPR to treat CCR as a non-hazardous waste; prior to that, EPA was set to issue a rule with only a hazardous-waste approach. All of which is to say that, just like the other regulations I have discussed herein, the trend of EPA regulation is constantly toward tighter, not looser, regulation of nearly all aspects of coal combustion byproducts, whether in the form of air emissions or solid wastes. Therefore, the prudent course for KU's customers is for KU to position itself and its facilities to be able to comply with the final CCR regulation now, particularly concerning the Brown Main Ash Pond, where stopping the current work to expand the pond and converting it to a dry-storage landfill now will likely save customers millions of dollars.

EPA Enforcement Actions and KU's Responses

Q. Are there any EPA enforcement actions that are giving rise to parts of KU's proposed 2011 Plan?

A. At least in part, yes. As the Commission is aware from KU's 2009 Plan proceeding, EPA required KU to build an SCR for Brown Unit 3 as the best available control technology ("BACT") to control NO_X, a requirement that resulted from what KU continues to believe was an erroneous interpretation of what constituted a "major modification" to the unit.[25] As a result of the consent decree into which KU entered with the U.S. Department of Justice (acting as EPA's counsel),[26] KYDAQ modified the Brown Title V operating permit to include a SAM emission limitation. (The Brown consent decree and Title V operating permit are attached hereto as Exhibits GHR-3 and GHR-4, respectively.)

At Ghent, KU has received two notices of violation ("NOVs") related to SAM emissions. In late November 2007, KU received an NOV citing an opacity violation at the common stack for Units 1 and 3. (See Exhibit GHR-1.) Then, in 2009, EPA issued an NOV based on its New Source Review ("NSR") and Prevention of Significant Deterioration ("PSD") rules, the latter of which places an explicit limit on SAM emissions increases. (See Exhibit GHR-2.) The NOV asserts that KU should have sought a PSD permit and installed BACT for SAM emissions following the installation of SCRs and FGDs for the Ghent units. KU is now attempting to settle

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[25] *See In the Matter of: The Application of Kentucky Utilities Company for Certificates of Public Convenience and Necessity and Approval of Its 2009 Compliance Plan for Recovery by Environmental Surcharge.*, Case No. 2009-00197, Testimony of John N. Voyles at 44-53 (June 30, 2009).

[26] Consent Decree filed on March 17, 2009 in U.S. District Court for the Eastern District of Kentucky, Central Division, Lexington, *United States of America v. Kentucky Utilities Company*, Civil Action No. 5:07-CV-0075-KSF ("Consent Decree").

these NOVs with EPA, and has offered to install permanent SAM mitigation systems at all the Ghent units.

The SAM mitigation components of the overall Particulate Matter Control Systems that KU proposes to install to serve all the Brown and Ghent units will address and meet these SAM-emission restrictions.

Recommendation

Q. What is your recommendation to the Commission?

A. The EPA's proposed CCR regulation, CATR, and HAPs Rule have created significant compliance obligations that KU cannot ignore, and any delay in beginning to take action to put in place the proposed compliance measures will serve only to place KU's customers at risk of bearing much higher compliance costs to achieve the same ends. Also, though KU has always striven to comply with all applicable environmental requirements, EPA has issued NOVs that necessitate KU's compliance concerning SAM emissions. I therefore recommend that the Commission approve KU's 2011 Plan as filed.

Q. Does this conclude your testimony?

A. Yes it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **Gary H. Revlett**, being duly sworn, deposes and says he is the Director, Environmental Affairs for LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Gary H. Revlett

Gary H. Revlett

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 27th day of May 2011.

Kimberly M Walters (SEAL)
Notary Public

My Commission Expires:

9/11/2012

APPENDIX A

Gary H. Revlett
Director, Environmental Affairs
LG&E and KU Services Company
220 West Main Street
Louisville, Kentucky 40202
(502) 627-4621

Education

University of Louisville, Ph.D. Analytical/Environmental Chemistry - May 1976

Murray State University, B.S. Chemistry - June 1971

OSHA Hazardous Waste Worker Training and 8-hour Refresher Courses

Previous Positions

E.ON U.S. Services Inc.

2006-2010 - Air Manager - Environmental Affairs

Tetra Tech EMI, Louisville, Kentucky

2005-2006 - Senior Air Quality Manager

Kenvirons, Inc., Frankfort, Kentucky

1994-2005 - Vice President and Treasurer
(Director of Air Services and Laboratory Services)

1985-1994 - Associate
(Manager of Testing and Air Services)

1978- 1984 - Senior Environmental Scientist
(Manager of Emission Testing and Air Modeling)

Kentucky Division of Pollution Control, Frankfort, KY

1976-1977 - Principal Chemist - Air Modeling Team

Exhibit GHR-1

Due to the voluminous nature of the exhibit, please see the compact disc included with this filing.

Exhibit GHR-2

Due to the voluminous nature of the exhibit, please see the compact disc included with this filing.

Exhibit GHR-3

Due to the voluminous nature of the exhibit, please see the compact disc included with this filing.

Exhibit GHR-4

Due to the voluminous nature of the exhibit, please see the compact disc included with this filing.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF KENTUCKY UTILITIES COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	))))))	CASE NO. 2011-00161

DIRECT TESTIMONY OF
CHARLES R. SCHRAM
DIRECTOR, ENERGY PLANNING, ANALYSIS AND FORECASTING
LG&E AND KU SERVICES COMPANY

Filed: June 1, 2011

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

A. My name is Charles R. Schram. I am the Director, Energy Planning, Analysis and Forecasting for LG&E and KU Services Company, which provides services to Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively "the Companies"). My business address is 220 West Main Street, Louisville, Kentucky, 40202. A complete statement of my education and work experience is attached to this testimony as Appendix A.

Q. Please describe your job responsibilities.

A. I am responsible for the development of load forecasts, market analysis, and the long-term planning of utility generation. As pertains to this proceeding, the Generation Planning group performed the analyses discussed below under my direction.

Q. Have you previously testified before this Commission?

A. Yes. I have previously testified before this Commission on several occasions, including in the Companies' most recent environmental cost recovery proceedings (Case Nos. 2009-00197 (KU) and 2009-00198 (LG&E)).

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following two exhibits, which were prepared under my direction:

Exhibit CRS-1 2011 Air Compliance Plan

Exhibit CRS-2 Coal Combustion Residuals Plan for E.W. Brown Station

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain the methods by which KU analyzed the projects included in its 2011 Environmental Compliance Plan ("2011 Plan"), present the evidence of the analysis, and make the final recommendations related to the most cost effective method of complying with applicable environmental laws and regulations.

Q. What is the nature of the projects in KU's 2011 Plan?

A. KU's 2011 Plan consists of (1) constructing Particulate Matter Control Systems to serve all of the coal generating units at the E.W. Brown and Ghent Generating Stations; (2) installing separate sulfuric acid mist ("SAM") mitigation systems on Brown Units 1 and 2 and Ghent Unit 2 (KU will also upgrade the existing separate SAM mitigation systems on Ghent Units 1, 3, and 4; Brown 3 already has planned a separate SAM mitigation system approved in the 2009 Compliance Plan with the Brown 3 SCR project); (3) modifying systems on Ghent Units 1, 3, and 4 to expand the generating-unit-operating range at which the selective catalytic reduction ("SCR") systems on those units can operate efficiently and to help ensure compliance with the CATR NOx emission reductions; and (4) converting Brown's Main Ash Pond to a dry-storage landfill for coal combustion residuals ("CCR"). These projects are explained in more detail in the testimony of John N. Voyles, and the testimony of Gary H. Revlett explains the various Clean Air Act and other environmental requirements that necessitate these projects.

Q. Please explain why the Energy Planning, Analysis and Forecasting department participated in analyzing the 2011 Plan.

A. As I mentioned concerning my job responsibilities, our department is responsible for the development of load forecasts, market analysis, and the long-term planning of utility generation. To fulfill our responsibilities, our department routinely performs multiple-scenario, complex system modeling to ensure our customers receive reliable service at the lowest reasonable cost. One example of our analytical work (and one of our primary responsibilities) is formulating the Companies' triennial Joint Integrated Resource Plan.

Because environmental regulations and the means the Companies use to comply with such regulations relate directly to generation planning and the availability of replacement market power, our department conducted important parts of the Companies' overall analysis of the projects in the 2011 Plan.

Projects 34 and 35: Brown and Ghent Air Compliance Projects

Q. What was the Energy Planning, Analysis, and Forecasting Group asked to do concerning the proposed 2011 Plan's air compliance projects?

A. Our group was asked to determine what would be the least-cost means of meeting the applicable new environmental regulations pertaining to air emissions (discussed in Mr. Revlett's testimony) for the Companies' generating fleet based on the data from the Companies' Project Engineering department. To accomplish that task, we performed careful analyses using the Strategist and PROSYM modeling and forecasting tools, as well as our collective expertise in these matters.

More specifically, we were asked to perform two related analyses. First, the Companies' Project Engineering department (working with an outside engineering firm, Black and Veatch) provided a suite of environmental compliance facilities for each coal unit in the Companies' generating fleet and asked us to determine whether all of the proposed facilities would be necessary to meet the applicable environmental regulations, some of which regulations require unit-by-unit compliance, some of which require compliance at the generating-station level, and others at the fleet level. Second, using the results of our first analysis to revise some of the proposed environmental controls (e.g., we eliminated possible new SCRs), we determined for each generating unit if it would be more cost-effective to install the facilities or to retire the unit and buy replacement power or generation.

Q. **What assumptions did you make in performing your analysis?**

A. We made two fundamental assumptions in performing our analyses. First, we assumed that the only options for our units were to operate in compliance with the applicable environmental regulations or to retire the units. We based this assumption on Mr. Revlett's expertise in the environmental regulatory field and the commonsense assumption that operating outside the applicable law in any area is unacceptable.

Second, we assumed that the proposed suite of environmental facilities for each unit was the most cost-effective suite of facilities for the unit; in other words, an analysis of numerous combinations of possible environmental controls for each unit was not necessary. The analyses performed by the Companies' Project Engineering department and Black and Veatch produced the most cost-effective suite of environmental controls to meet the applicable environmental requirements. The Environmental Air Compliance Strategy for Kentucky Utilities Company and Louisville Gas and Electric Company, attached to Mr. Voyles's testimony as Exhibit JNV-2, explains how the Project Engineering department and Black and Veatch determined the proposed suite of environmental facilities for each unit.

Q. **Please discuss the evaluation of the Brown and Ghent air compliance projects.**

A. The analysis evaluated the construction of environmental controls compared to the retirement of the generating unit(s) to determine the least cost method of meeting the air regulations. With the exception of Brown Units 1-2, the Brown and Ghent air compliance projects were evaluated on an individual-unit basis as part of a system analysis of the KU and LG&E generating assets, which are jointly dispatched to economically serve the Companies' customers. Brown Units 1-2 were considered together given the potential for installation of joint controls for the units. In evaluating the unit retirement options, a least-cost resource expansion plan was developed to replace the retired capacity. This approach is fully described in exhibit CRS-1. The replacement generation technology, if required, is expected to be a natural gas-fired combined cycle combustion turbine.

The recommended projects result in the lowest Present Value Revenue Requirements ("PVRR") over 30 years, including the impacts from capital investment and Operations and Maintenance ("O&M") costs. Capital costs consist of the cost of environmental controls or, in the case of each retirement option, the cost of replacement generation identified in the respective resource expansion plan. O&M costs include the system production costs associated with the unit dispatch resulting from each option.

Analytical tools used in the assessment include Strategist,[1] an application used to identify the least-cost generating resource expansion plan and the associated system production costs, and PROSYM.[2] The Companies compile information regarding the cost of generation for each unit (e.g., fuel, variable O&M, and emission allowance costs), a description of the generation capabilities of each unit (e.g., capacity, heat rate curve, commitment parameters, emission rates, and availability schedules), a load forecast, the market price of electricity, and the volumetric ability (transfer capability) to access the market to make economical power purchases (if and to the extent such exist). All of this information is brought together in Strategist to

[1] Strategist was used for the resource expansion modeling activities in the 2011 Integrated Resource Plan.
[2] The PROSYM model has formed the foundation of prior analyses involving certificates of convenience and necessity for new generating plants, environmental cost recovery for pollution control equipment, and the fuel adjustment clause.

model the economic operation of the Companies' generating system. The results produced by this model are checked for reasonableness by comparing the results to historical data. The preparation of the forecast by experienced analysts spending significant amounts of time developing models and assumptions, gathering input data, and reviewing results also improves the likelihood of a reasonable forecast.

Constructing the proposed environmental controls and performing the proposed work on existing generating units and environmental controls for each of the Brown and Ghent units results in a lower PVRR for each unit, as shown in Table 1 below.

Table 1:
PVRR Savings for Brown and Ghent Units (Compared to Retiring the Units)

Unit	PVRR Savings ($ millions)	Capital Cost ($ millions)
Brown 1-2	228	228
Brown 3	601	118
Ghent 1	794	164
Ghent 2	1,139	165
Ghent 3	914	199
Ghent 4	1,155	185

Exhibit CRS-1 hereto contains the detailed analysis supporting the figures in the table above.

The Companies have also reviewed approaches to further decrease NOx emissions from SCR-equipped units, and recommend improvements to existing systems to manage the inlet temperature ranges of SCRs at KU's Ghent station, which is equipped with SCRs on Units 1, 3, and 4. These improvements involve economizer modifications which will raise the boiler exit gas temperature, expanding the operating range for the SCRs. This will contribute to lower NO_X emissions at low loads and further ensure system NO_X compliance with the Clean Air Transport Rule ("CATR").

The evaluation of the Green River and Tyrone generating units resulted in a recommendation to retire those units. The retirement of Green River Unit 3, Green River Unit 4, and Tyrone Unit 3 result in lower PVRR of $80 million, $110 million, and $13 million, respectively, compared to installing controls. The expense of installing a suite of environmental controls, including flue-gas desulfurization systems and Particulate Matter Control Systems, is not economical on these units.

Amended Project 29: Brown Main Ash Pond to CCR Storage Landfill Conversion

Q. Please discuss the evaluation of the CCR Storage Landfill conversion found in Amended Project 29 at the E.W. Brown Generating Station.

A. The evaluation consisted of a review of five options, two of which the Project Engineering department determined would be infeasible given the anticipated CCR storage regulations (as discussed in Exhibit CRS-2). The three remaining options were further evaluated to determine which option would be least-cost. Option 1 stops construction of the Main Pond Starter Dike immediately, completes the expansion of the Aux Pond to 900 feet by 2012, and converts the Main Pond to a dry landfill by 2014. Option 2 continues the construction of the Main Pond Starter Dike, continues the expansion of the Aux Pond by 2014, and converts the Main Pond to a landfill by 2016. Option 3 stops construction of storage at Brown and hauls CCR to an offsite commercial landfill.

During the design, permitting, and construction of the Brown landfill in Option 1, CCR will be stored in the Aux Pond for approximately 2.5 years. With Option 2, both the Aux Pond and Main Pond will be used to store CCR during the design and permitting of the landfill. During construction of the landfill, a duration of approximately 2 years, CCR will be stored only in the existing Aux Pond. With both options, a portion of the gypsum produced would be used in construction of the Aux Pond and landfill. Using surveys of the Aux Pond conducted in April 2011 and Brown's current CCR production forecast, it is expected that for both onsite landfill options, the Aux Pond will have the capacity needed to accommodate Brown's CCR storage needs until the landfill is placed in service. Both proposed landfill options can accommodate Brown's long-term CCR forecast. The capital expenditures for both on-site options include capital for the construction of the Aux Pond, Main Pond (Option 2), and landfill. O&M expenses for both on-site options include gypsum dewatering during the aux pond construction and landfill operation expenses once the landfill is open. The off-site storage option represents the projected O&M costs of hiring a contractor to haul Brown's CCR to an off-site commercial landfill.

Q. Is this project a cost-effective means of complying with environmental regulations and permits?

A. Yes, Option 1 results in $23 million PVRR lower than Option 2 and $80 million PVRR lower than Option 3.

Recommendation

Q. What is your recommendation to the Commission?

A. Based on my testimony and the analyses performed under my direction and attached hereto, it is my recommendation that the Commission should approve the projects proposed in KU's 2011 Plan as cost-effective methods of complying with current and proposed environmental laws.

Q. Does this conclude your testimony?

A. Yes it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **Charles R. Schram**, being duly sworn, deposes and says that he is Director – Energy Planning, Analysis and Forecasting for LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Charles R. Schram

Charles R. Schram

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 27th day of May 2011.

Kimberly M Walters (SEAL)
Notary Public

My Commission Expires:

9/11/2012

APPENDIX A

Charles R. Schram

Director, Energy Planning, Analysis and Forecasting
LG&E and KU Services Company
220 West Main Street
Louisville, Kentucky 40202
(502) 627-3250

Education

Master of Business Administration
University of Louisville, 1995
Bachelor of Science – Electrical Engineering
University of Louisville, 1984
E.ON Academy General Management Program: 2002-2003
Center for Creative Leadership, Leadership Development Program: 1998

Professional Experience

LG&E and KU

Director, Energy Planning, Analysis & Forecasting	May 2008 – Present
Manager, Transmission Protection & Substations	2006 – 2008
Manager, Business Development	2005 – 2006
Manager, Strategic Planning	2001 – 2005
Manager, Distribution System Planning & Eng.	2000 – 2001
Manager, Electric Metering	1997 – 2000
Information Technology Analyst	1995 – 1997

U.S. Department of Defense – Naval Ordnance Station

Manager, Software Integration	1993 – 1995
Electronics Engineer	1984 – 1993

Exhibit CRS- 1

2011 Air Compliance Plan

PPL companies

Generation Planning & Analysis
May 2011

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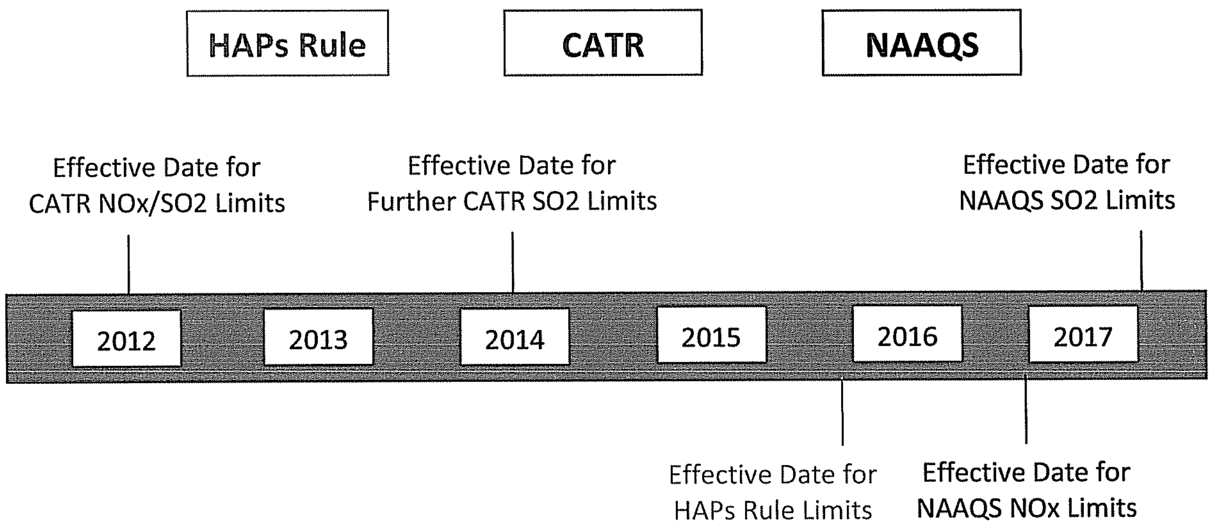
1.0 Executive Summary

In July 2010, the Environmental Protection Agency ("EPA") issued a proposed Clean Air Transport Rule ("CATR") that provides limited allowances for NO_x and SO_2 emissions starting in 2012. In March 2011, the EPA issued a proposed rule aimed at reducing hazardous air pollutants (such as mercury, other metals, acid gases, and organic air toxics, including dioxins) from new and existing coal- and oil-fired electric utility steam generating units ("HAPs Rule"). In addition to these proposed rules, the EPA's National Ambient Air Quality Standards ("NAAQS") will further restrict NO_x and SO_2 emissions beginning in 2016 and 2017. Key dates in the implementation of these regulations are summarized below in Figure 1.

Figure 1 – Environmental Regulations Timeline



To comply with the proposed regulations at each of its coal units, LG&E and KU (the "Companies") must either install additional emission controls or retire and replace the capacity. The process of determining the least-cost compliance plan consists of the following three tasks:

1. The Companies (in conjunction with Black & Veatch, an engineering consulting firm) developed construction cost estimates for the least-cost option for installing emission controls at each unit to comply with EPA regulations.
2. Where compliance with the aforementioned environmental regulations is not measured on a unit-by-unit basis (CATR and HAPs Rule), the Companies conducted an analysis to demonstrate the need for emission controls on a station- or system-wide basis.
3. After the need for controls was established and the total expenditures for each unit were determined, the Companies compared the revenue requirements of installing controls to the revenue requirements of retiring and replacing capacity.

The results of the needs assessment (task #2) are summarized in Table 1. The control technologies in Table 1 would be required to comply physically with the proposed environmental regulations.

The Companies also developed cost estimates for installing SCRs on the Brown 1, Brown 2, Ghent 2, Mill Creek 1, and Mill Creek 2 units. However, the needs assessment demonstrated that this equipment is not needed to comply with NAAQS or the CATR at this time.

Table 1 – Capital Costs for Environmental Controls

Unit	Control Technologies	Total Capital ($M)
Brown 1 & 2	Baghouse[1], SAM[2] Mitigation	228
Brown 3	Baghouse	118
Cane Run 4	FGD[3], SCR[4], Baghouse, SAM Mitigation	295
Cane Run 5	FGD, SCR, Baghouse, SAM Mitigation	310
Cane Run 6	FGD, SCR, Baghouse, SAM Mitigation	399
Ghent 1	Baghouse, SAM Mitigation/Economizer Modifications	164
Ghent 2	Baghouse, SAM Mitigation	165
Ghent 3	Baghouse, SAM Mitigation/Economizer Modifications	199
Ghent 4	Baghouse, SAM Mitigation/Economizer Modifications	185
Green River 3	CDS[5] Fabric Filter	45
Green River 4	CDS Fabric Filter	66
Mill Creek 1 & 2	FGD[6], Baghouse	666
Mill Creek 3	FGD, Baghouse, SAM Mitigation/Economizer Modifications	225
Mill Creek 4	FGD, SCR Upgrade, Baghouse, SAM Mitigation/Economizer Modifications	386
Trimble County 1	Baghouse	124
Tyrone 3	CDS Fabric Filter	45

The differences in present value of revenue requirements ("PVRR") between (a) installing controls and (b) retiring and replacing capacity are summarized in Table 2.[7] The decisions to install controls were evaluated on a unit-by-unit basis except for cases where the least-cost compliance alternative is to install one control on multiple units (i.e., Brown 1 and 2 and Mill Creek 1 and 2).

[1] The least-cost compliance plan for Brown 1-2 is to install one baghouse to be shared by Brown 1 and 2.
[2] Sulfuric acid mist.
[3] Flue gas desulfurization.
[4] Selective catalytic reduction.
[5] Circulating dry scrubber.
[6] The least-cost compliance plan for Mill Creek 1-2 is to install one new FGD to be shared by Mill Creek 1 and 2.
[7] The values in Table 2 are in 2011 dollars and based on a 30-year study period (2011-2040).

Table 2 – PVRR of Installing Controls vs. Retiring and Replacing Capacity ($M, $2011)

Unit(s)	Install Controls (A)	Retire/Replace Capacity (B)	Difference (A)-(B)
Tyrone 3	33,153	33,140	(13)
Green River 3	33,140	33,060	(80)
Brown 3	33,060	33,661	601
Cane Run 4	33,060	32,972	(88)
Cane Run 6	32,972	32,980	8
Brown 1-2	32,980	33,208	228
Cane Run 5	32,980	32,921	(58)
Ghent 3	32,921	33,836	914
Ghent 1	32,921	33,715	794
Green River 4	32,921	32,811	(110)
Mill Creek 4	32,811	33,671	859
Trimble County 1	32,811	33,804	993
Ghent 4	32,811	33,966	1,155
Mill Creek 3	32,811	33,567	756
Ghent 2	32,811	33,950	1,139
Mill Creek 1-2	32,811	33,833	1,022

The cases to install controls considered the capital and fixed operating and maintenance ("O&M") costs of the controls as well as the associated impact on total system production costs. The cases to retire and replace capacity considered the capital and fixed O&M savings associated with retiring a unit, the costs of installing and operating replacement capacity, and the overall impact of the modified generation portfolio on system production costs.

The least-cost plan for complying with the proposed environmental regulations includes installing additional environmental controls on the Brown, Ghent, Mill Creek, and Trimble County 1 coal units (see Table 2). Installing controls on the Green River, Tyrone, and Cane Run 4-5 coal units is not cost-effective. In the case of Cane Run 6, the difference in PVRR between installing controls and retiring the unit is negligible ($8 million). If the Companies install controls on Cane Run 6 and the PVRR of a future expenditure not contemplated in this analysis exceeds $8 million, installing controls is not the least-cost option. Because the likelihood of this occurring is considered high, the Companies do not recommend installing environmental controls on Cane Run 6. As a result, Cane Run 6, along with the Green River, Tyrone, and the other Cane Run coal units, will be retired when the regulations take effect.

The costs of the projects in the least-cost compliance plan are summarized in Table 3. The total capital cost for KU is $1,058 million. The total capital cost for LG&E is $1,400 million.

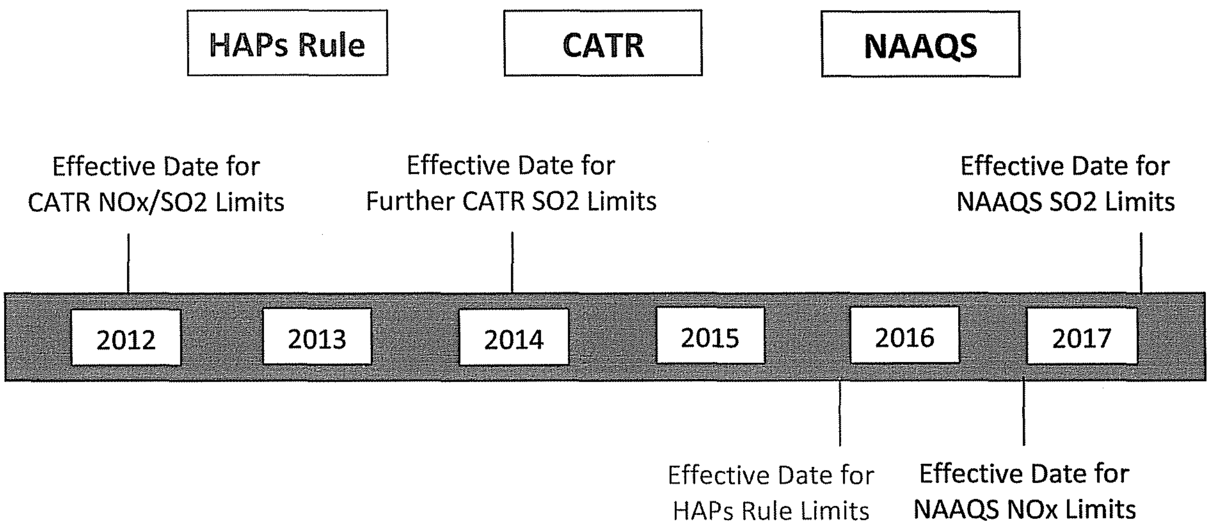
Table 3 – Proposed Capital Costs

Company	Generating Unit	Capital ($M)
KU	Brown 1-2	228
KU	Brown 3	118
KU	Ghent 1	164
KU	Ghent 2	165
KU	Ghent 3	199
KU	Ghent 4	185
KU	**Total**	**1,058**
LG&E	Mill Creek 1 -2	666
LG&E	Mill Creek 3	225
LG&E	Mill Creek 4	386
LG&E	Trimble County 1	124
LG&E	**Total**	**1,400**

2.0 Summary of Environmental Regulations

The EPA's National Ambient Air Quality Standard ("NAAQS"), Clean Air Transport Rule ("CATR"), and HAPs Rule are precipitating the need for additional emission controls over the next several years. Key dates in the implementation of these regulations are summarized below in Figure 2. Each of these regulations is discussed in more detail in the following sections.

Figure 2 – Environmental Regulations Timeline



2.1 National Ambient Air Quality Standard

The EPA's NAAQS places further restrictions on SO_2 and NO_x emissions beginning in 2016 and 2017. Unlike the proposed CATR and HAPs Rule, the NAAQS is final. Compliance with NAAQS emission limits are measured on a unit-by-unit basis. Table 4 summarizes the Companies' current (2010) SO_2 and NO_x emissions, as well as the NAAQS emission limits.

Table 4 – NAAQS Emission Limits

	Current Emissions (2010)		NAAQS Requirements	
Unit	**SO_2 Rate (lb/mmBtu)**	**NO_x Rate (lb/mmBtu)**	**SO_2 Rate (lb/mmBtu)**	**NO_x Rate (lb/mmBtu)**
Brown	1.26[8]	0.34	0.40	0.50
Cane Run	0.55	0.34	0.06	0.07
Ghent	0.17	0.12	0.31	0.47
Green River	4.08	0.40	0.15	0.56
Mill Creek	0.52	0.16	0.25	0.39
Trimble County	0.07	0.05	0.50	0.50
Tyrone	1.33	0.48	0.60	0.50

To comply with the NAAQS, new NO_x emission controls must be installed at the Cane Run station by 2016. New SO_2 emission controls must be installed at the Cane Run, Green River, Mill Creek, and Tyrone stations by 2017 (see Table 4). The Cane Run units have first generation FGDs built in the 1970s. In addition, the Cane Run units are not equipped with SCRs. Cane Run will require extensive FGD improvements and new SCR controls to comply with NAAQS regulations.

2.2 Clean Air Transport Rule

In July 2010, the Environmental Protection Agency ("EPA") issued a proposed Clean Air Transport Rule ("CATR") which provides limited allowances for NO_x and SO_2 emissions starting in 2012. In 2014, allowances for SO_2 emissions will be reduced further. Compliance with the CATR is measured on a system-wide basis. Table 5 summarizes the 2012 and 2014 limits as well as the Companies' current (2010) SO_2 and NO_x emissions.

Table 5 – Allocation of CATR Allowances

	Current Emissions	CATR Allowances	
	2010	**2012**	**2014**
SO_2 Emissions (Tons)	92,241	67,909	44,448
NO_x Emissions (Tons)	31,826	24,213	24,213

To comply with the CATR, the Companies' SO_2 emissions will have to decrease by more than 50% by 2014; the Companies' NO_x emissions will have to decrease by approximately 14%. The NAAQS imposes stricter limits on NO_x and SO_2 emissions beginning in 2016 and 2017. However, the CATR may create the need to build NO_x and SO_2 controls before then.

2.3 HAPs Rule

In March 2011, the EPA issued a proposed HAPs Rule aimed at reducing hazardous air pollutants (such as mercury, other metals, acid gases, and organic air toxics, including dioxins) from new and existing coal- and oil-fired electric utility steam generating units. The rule is expected to take effect in November 2015. The HAPs Rule limits mercury (Hg) and particulate matter (PM), the latter including SAM (as a condensable particulate). The current mercury and particulate matter emissions

[8] The Brown units' 2010 SO_2 emission rates do not reflect the full impact of the FGD that was installed in late 2010. With this FGD, the Brown units comply with NAAQS SO_2 limits.

for the Companies' coal units are summarized in Table 6. With the exception of Trimble County 2, the emissions of all of the Companies' coal units exceed at least one of the proposed limits.

Table 6 – Current HAPs Emissions

Unit	Summer Capacity	Hg Emissions (lb/TBtu)	PM Emissions (lb/mmBtu)
Brown 1	105	2.0	0.029
Brown 2	167	2.0	0.029
Brown 3	416	2.0	0.029
Cane Run 4	155	4.8	0.081
Cane Run 5	168	4.8	0.081
Cane Run 6	240	4.8	0.081
Ghent 1	493	2.0	0.051
Ghent 2	490	4.0	0.060
Ghent 3	454	4.0	0.060
Ghent 4	487	2.4	0.073
Green River 3	68	4.8	0.081
Green River 4	95	4.8	0.081
Mill Creek 1	303	4.8	0.081
Mill Creek 2	301	4.8	0.081
Mill Creek 3	391	1.7	0.098
Mill Creek 4	477	1.9	0.085
Trimble County 1	383	1.2	0.033
Trimble County 2	549	0.6	0.005
Tyrone 3	71	4.8	0.065
HAPs Rule Limits		**1.0** [9]	**0.030**

Note: The actual values in Table 6 are annual averages.

3.0 Process and Methodology

The Companies determined the least-cost plan for complying with the NAAQS, the CATR, and the HAPs Rule (collectively, the "air regulations"). The process of identifying this plan consists of the following three tasks that were performed by departments within the Companies, and are discussed further in the following sections:

- Development of least-cost options for installing emission controls
- Demonstration of need for controls
- Revenue requirements analysis

[9] On May 18, 2011, EPA issued a letter acknowledging that this emission limit is incorrect due to computational errors, and that a value of 1.2 is correct. It still represents a "90 percent reduction from the mercury in the coal used by power plants."

3.1 Development of Least-Cost Options for Installing Emission Controls

The Companies contracted with Black and Veatch, an engineering consulting firm, to provide the conceptual engineering and scoping of the least-cost option for installing emission controls at each unit as well as construction cost estimates for these options. The Companies worked with Black and Veatch to provide all of the emission control facilities cost and performance data used in the analyses described herein. The detailed process by which the Companies and Black and Veatch arrived at the various suites of environmental control facilities to be placed on each unit is described in the Environmental Air Compliance Strategy Summary for Kentucky Utilities Company and Louisville Gas and Electric Company.

3.2 Demonstration of Need for Controls

Where compliance with the air regulations is not measured on a unit-by-unit basis (CATR and HAPs Rule), the Companies first conducted an analysis to demonstrate the need for emission controls on a station- or system-wide basis. The NAAQS limits the rate of NO_x and SO_2 emissions on a unit-by-unit basis beginning in 2016 and 2017. Furthermore, the CATR limits system-wide SO_2 and NO_x emissions beginning in 2012 and 2014. To determine whether additional controls are needed to comply with the NAAQS, current SO_2 and NO_x emission rates were compared to NAAQS limits. Then, the PROSYM production model was used to model system NO_x and SO_2 emissions with the controls required to comply with NAAQS to determine whether additional controls were need to comply with the CATR. This analysis is summarized in more detail in section 4.1.1.

With the exception of Trimble County 2, the emissions of hazardous air pollutants for all of the Companies' coal units exceed the proposed limits in the HAPs Rule. Since compliance with the HAPs Rule will be measured on a station-by-station basis, it was necessary to determine for each generating station if controls were needed on all units or only some units to meet the station-wide emissions limitations. This analysis is summarized in more detail in section 4.1.2.

Both of these analyses focus on the need for controls. A separate analysis ("Revenue Requirements Analysis") was conducted to demonstrate the prudency of installing controls at a given unit (versus retiring the unit and replacing the capacity).

3.3 Revenue Requirements Analysis

Once the need for controls was determined, the cost of control technologies was summarized by unit. Since the alternative to installing controls is to retire the unit and replace the capacity, the Companies conducted an analysis to compare the revenue requirements of installing controls to the revenue requirements of retiring and replacing capacity. The decisions to install controls were evaluated on a unit-by-unit basis except for cases where the least-cost compliance alternative is to install one control on multiple units (i.e., Brown 1 and 2 and Mill Creek 1 and 2). The units were evaluated in order of decreasing variable operating costs (i.e., units with higher variable operating costs were evaluated first). If – for a given unit – the revenue requirements of retiring and replacing capacity are lower than the revenue requirements of installing controls, that unit is assumed to be retired when the decision to install controls is evaluated for the next unit. This way, the decision to install controls for each unit is evaluated under realistic circumstances.

The analysis was conducted using Strategist resource planning software.[10] The Strategist model has formed the foundation of prior analyses involving certificates of public convenience and necessity for new generating plants, environmental cost recovery for pollution control equipment, and the fuel adjustment clause. This software is utilized for resource planning and to model the economic operation of the Companies' generating system.

The Companies evaluated all of the options to determine the PVRR associated with the capital expenditures and O&M expenses of each option. This is performed using the Capital Expenditure Recovery ("CER") module of the Strategist software model.

Used together, Strategist and the CER have the capability of simulating production costs (e.g., fuel, fixed and variable operation and maintenance, and emissions costs) and quantifying the revenue requirements impact associated with capital projects. Appendix A contains the economic and forward-looking assumptions used in this analysis.

[10] Strategist® is a proprietary resource planning computer model.

4.0 Detailed Analysis

The Companies (in conjunction with Black & Veatch) determined the least-cost option for installing emission controls at each unit as well as construction cost estimates for these options. A detailed summary of these estimates is included in Appendix B. The following sections provide a detailed summary of the work the Companies performed to (a) demonstrate the need for emission controls and (b) evaluate the prudency of installing these controls by comparing the revenue requirements of installing controls to the revenue requirements of retiring and replacing capacity.

4.1 Demonstration of Need for Controls

Where compliance with the air regulations is not measured on a unit-by-unit basis (CATR and HAPs Rule), the Companies conducted a two-part analysis to demonstrate the need for these emission controls on a station- or system-wide basis. The first part addressed the need for SO_2 and NO_x controls to comply with the NAAQS and proposed CATR. The second part addressed the need for controls to comply with the HAPs Rule. Each of these parts is summarized in the following sections.

4.1.1 SO_2 and NO_x Controls

The EPA's NAAQS places further restrictions on the rate of SO_2 and NO_x emissions beginning in 2016 and 2017. Table 4 on page 7 summarizes the Companies' current (2010) SO_2 and NO_x emission rates as well as the NAAQS emission limits. To comply with the NAAQS, new NO_x emission controls must be installed at the Cane Run station by 2016, and new SO_2 emission controls must be installed at the Cane Run, Green River, Mill Creek, and Tyrone stations by 2017. For a given unit, the alternative to installing these controls is retiring and replacing the capacity.

The proposed limits for the CATR take effect in 2012 and 2014. While the CATR is designed as a cap-and-trade program with annual emissions caps, the EPA has indicated that, at best, only limited interstate allowance trading will be permitted, and such trading may be prohibited entirely. Therefore, the Companies have assumed that physical compliance on a system-wide basis is required. Because of the shortfall that exists between the Companies' current emissions and its CATR allocations (see Table 5 on page 7), this assumption accelerates the need for the SO_2 and NO_x controls required to comply with the NAAQS. Table 7 summarizes the SO_2 and NO_x controls needed to comply with NAAQS.

Table 7 – SO_2 and NO_x Controls Needed to Comply with NAAQS

Unit(s)	Control
Cane Run 4	FGD and SCR
Cane Run 5	FGD and SCR
Cane Run 6	FGD and SCR
Green River 3	CDS Fabric Filter
Green River 4	CDS Fabric Filter
Mill Creek 1 & 2	Combined 1&2 FGD
Mill Creek 3	FGD
Mill Creek 4	FGD
Tyrone 3	CDS Fabric Filter

To determine whether additional SO_2 and NO_x controls are needed to comply with the CATR, the PROSYM production model was used to model system NO_x and SO_2 emissions with the controls needed to comply with NAAQS. In this analysis, these controls were assumed to be installed by 2014. Table 8 summarizes the results of this analysis under normal and high load scenarios.[11]

Table 8 – System NO_x and SO_2 Emissions with Controls Needed to Comply with NAAQS

	Normal Load		High Load	
Year	NOx Surplus/(Deficit)	SO2 Surplus/(Deficit)	NOx Surplus/(Deficit)	SO2 Surplus/(Deficit)
2012	286	10,857	(384)	9,196
2013	302	11,920	(423)	9,605
2014	4,519	10,490	4,003	9,943
2015	4,201	18,841	3,647	18,430
2016	2,079	20,018	1,568	19,662

Under normal load conditions, system NO_x and SO_2 emissions are lower than CATR allocations. However, under high load conditions, system NO_x and SO_2 emissions are higher than CATR allocations in 2012-2013. The most cost-effective alternative for reducing NO_x emissions in 2012-2013 is to upgrade the Mill Creek 4 SCR. Other alternatives for adding NO_x controls are more costly and cannot be implemented by 2012. The Mill Creek 4 SCR upgrade project has a capital cost of $6 million and is expected to reduce NO_x emissions at Mill Creek 4 by approximately 25% or 250 tons per year. The alternative to installing controls for reducing NO_x emissions is to displace coal generation with gas generation. Conservatively, the difference in fuel cost between Mill Creek 4 and a gas combustion turbine is $20/MWh. On average, Mill Creek 4 produces approximately 3.8 TWh per year. 25% of this total is approximately 950 GWh. If this amount of coal generation is displaced by gas generation, the incremental fuel cost would be $19 million in a single year. Clearly, upgrading the Mill Creek 4 SCR is a lower cost alternative for reducing NO_x emissions than displacing coal generation with gas.

While upgrading the Mill Creek 4 SCR is not expected to eliminate the NO_x emission deficit under high load conditions entirely, it will provide some much needed margin between expected emissions and the CATR allocations. Moreover, if the cost at some units of installing the controls required to comply NAAQS is greater than the cost to retire the units and replace the capacity, the emission

[11] The probability of the high load scenario occurring is about 5% (1 year out of 20).

surplus or deficit in 2014-2015 will be similar to that in 2012-2013. In this case, the NO_x emission reductions associated with the Mill Creek 4 SCR upgrade will be even more valuable.

In addition to the Mill Creek 4 SCR upgrade, the Companies have reviewed approaches to further improve the performance of SCR-equipped units and recommend economizer modifications on Mill Creek 3-4, Ghent 1, and Ghent 3-4 to enable operation of the SCRs at lower load levels. This will further contribute to lower NO_x emissions at low loads and further ensure NO_x compliance with the CATR during the years where NO_x emissions are projected to approach emission limits.

Table 9 summarizes NO_x and SO_2 emissions in a scenario with the Mill Creek 4 SCR upgrade and where no controls are added to the Cane Run, Green River, or Tyrone coal units. In this scenario, the Cane Run, Green River, and Tyrone coal units are retired at the end of 2015 and replaced with gas capacity. NO_x emissions are consistently below CATR allocations under normal load conditions. However, prior to 2016, NO_x emissions exceed CATR allocations with one exception under high load conditions. The reductions in NO_x emissions associated with the Mill Creek SCR upgrade are particularly valuable in this scenario. With the ability to carry surplus allowances to future years, the probability of being short NO_x (or SO_2) allowances in a given year is low.

Table 9 - System NO_x and SO_2 Emissions; No Controls on Cane Run, Green River, or Tyrone

	Normal Load		High Load	
Year	NOx Surplus/(Deficit)	SO2 Surplus/(Deficit)	NOx Surplus/(Deficit)	SO2 Surplus/(Deficit)
2012	449	10,821	(220)	9,161
2013	558	11,885	(165)	9,571
2014	969	1,164	162	(1,329)
2015	254	1,795	(505)	(339)
2016	2,978	21,171	2,615	20,896

Based on this analysis, in addition to the controls required to comply with NAAQS, a Mill Creek 4 SCR upgrade is needed to comply with the CATR. The construction of additional SCRs at Mill Creek 1-2, Ghent 2, and Brown 1-2 is not recommended at this time.

4.1.2 Hazardous Air Pollutants Controls

With the exception of Trimble County 2, the emissions of hazardous air pollutants ("HAPs") for all of the Companies' coal units exceed at least one of the proposed limits in the HAPs Rule (see Table 6 on page 8). However, since compliance with the HAPs Rule is measured on a station-by-station basis, installing controls on all of these units may not be necessary. At a given station, it may be possible to do nothing or install less costly (and less effective) controls on one unit and then offset the higher emissions from this unit with lower emissions from other units.

A baghouse is the most effective control technology for HAPs emissions. A baghouse is expected to reduce mercury emissions to 0.6 pounds per TBtu and particulate matter emissions to 0.0258 pounds per mmBtu. As seen in Table 6, the HAPs limits are 1.0 pounds per TBtu for mercury and

0.03 pounds per mmBtu for particulate matter.[12]

The alternatives to installing a baghouse are (a) do nothing or (b) upgrade the precipitator. A precipitator upgrade has little impact on mercury emissions and only modest impacts on particulate matter emissions. Still, since compliance with the HAPs rules is measured on a station-by-station basis, a less-costly precipitator upgrade may be sufficient for meeting HAPs limits.

In the first year of the program, compliance with the HAPs Rule is measured on a monthly basis as the heat input-weighted average of emissions. For this reason, the units at each station that are the most likely candidates for not installing additional controls (or for installing less-costly, less effective controls) are the smaller units with lower HAPs emissions. Based on the information in Table 6, these units are Brown 1-2,[13] Cane Run 4, Ghent 1, Green River 3, Mill Creek 2, and Trimble County 1.

Table 10 summarizes the impact on station HAPs emissions of upgrading the precipitator at Cane Run 4, Ghent 1, Green River 3, and Mill Creek 2. Because, according to engineering studies, a precipitator upgrade is not expected to reduce particulate matter emissions for Brown 1-2 or Trimble County 1, no additional controls are assumed to be added to these units.

[12] On May 18, 2011, EPA issued a letter acknowledging that this emission limit is incorrect due to computational errors, and that a value of 1.2 is correct. It still represents a "90 percent reduction from the mercury in the coal used by power plants."

[13] Brown 1-2 are considered together since the least-cost alternative for complying with HAPs rules involves installing one baghouse for both units. Since the Tyrone station consists of only one unit, a baghouse is the only alternative for complying with HAPs.

Table 10 – Impact of Not Installing Baghouses on Selected Units for HAPs Compliance

Unit	Control Technology	Max Capacity	Hg Emissions (lbs/Tbtu)	PM Emissions (lbs/mmBtu)
Brown 1	No Additional Controls	105	2.00	0.029
Brown 2	No Additional Controls	167	2.00	0.029
Brown 3	Baghouse	416	0.60	0.026
Brown Station – Weighted Average			**1.15**	**0.027**
Cane Run 4	Precipitator Upgrade	155	4.80	0.061
Cane Run 5	Baghouse	168	0.60	0.026
Cane Run 6	Baghouse	240	0.60	0.026
Cane Run Station – Weighted Average			**1.76**	**0.035**
Ghent 1	Precipitator Upgrade	493	2.00	0.047
Ghent 2	Baghouse	490	0.60	0.026
Ghent 3	Baghouse	454	0.60	0.026
Ghent 4	Baghouse	487	0.60	0.026
Ghent Station – Weighted Average			**0.96**	**0.031**
Green River 3	Precipitator Upgrade	68	4.80	0.061
Green River 4	Baghouse	95	0.60	0.026
Green River Station – Weighted Average			**2.35**	**0.040**
Mill Creek 1	Precipitator Upgrade	303	0.60	0.026
Mill Creek 2	Baghouse	301	4.80	0.061
Mill Creek 3	Baghouse	391	0.60	0.026
Mill Creek 4	Baghouse	477	0.60	0.026
Mill Creek Station – Weighted Average			**1.46**	**0.033**
Trimble County 1	No Additional Controls	383	1.20	0.033
Trimble County 2	Baghouse (Existing)	549	0.60	0.005
Trimble County Station – Weighted Average			**0.85**	**0.017**

Note: Weighted averages assume all units operate for the entire month.

The weighted averages in Table 10 are computed based on the assumption that all units operate for the entire month. This is a conservative way to estimate the impact of fewer controls on HAPs emissions, since the rates of HAPs emissions will clearly increase if the controlled units do not operate the entire month. If the units without baghouses do not operate the entire month, the rates of HAPs emissions will decrease. However, this scenario was not considered because a compliance strategy that limits the operation of 'less-controlled' units is not a viable strategy. Based on the results in Table 10 (and the assumption that all units operate the entire month), HAPs emissions at all stations except Trimble County will exceed at least one of the proposed limits if a baghouse is not installed on all units.

Since the rates of HAPs emissions will increase if the controlled units do not operate the entire month, the ability to operate Trimble County 1 will be subject to the monthly operation of Trimble County 2. Furthermore, monthly HAPs emissions are variable, so Trimble County 1 operation will also be subject to the variation in HAPs emissions from Trimble County 2 in the event that higher emissions from Trimble County 2 push the station closer to the monthly limit. Due to this risk of significant restrictions on Trimble County 1 operation (particularly under peak load conditions), the Companies recommend installing a baghouse on Trimble County 1 as well.

In summary, if the proposed HAPs limits are met through construction of controls, a baghouse is needed on all coal units except Trimble County 2. The following section will examine the prudency of installing these controls (and the controls needed to comply with the NAAQS and CATR) versus retiring and replacing capacity.

4.2 Revenue Requirement Analysis

Table 11 provides a summary of the emission control equipment that, based on the needs assessment, would be required to comply physically with the proposed environmental regulations. Since the alternative to installing emission controls is to retire the unit and replace the capacity, the Companies evaluated the revenue requirements of these options. The decisions to install controls were evaluated on a unit-by-unit basis except for cases where the least-cost compliance alternative is to install one control on multiple units (i.e., Brown 1 and 2 and Mill Creek 1 and 2). The analysis was conducted using Strategist resource planning software. Appendix A provides a summary of key assumptions for this analysis. Since capital investments on units with higher variable costs (and, as a result, lower capacity factors) are generally less economic, the units were evaluated in the order of decreasing variable production costs. The analyses for each unit are summarized in the following sections.

Table 11 – Capital Cost Estimates for Emission Controls ($M)

	Capital ($M)		
Unit	**NAAQS/CATR**	**HAPs Rule**	**Total**
Brown 1-2		228	228
Brown 3		118	118
Cane Run 4	252	43	295
Cane Run 5	265	46	310
Cane Run 6	339	59	399
Ghent 1		164	164
Ghent 2		165	165
Ghent 3		199	199
Ghent 4		185	185
Green River 3		45	45
Green River 4		66	66
Mill Creek 1-2	359	307	666
Mill Creek 3	74	150	225
Mill Creek 4	224	162	386
Trimble County 1		124	124
Tyrone 3		45	45

4.2.1 Tyrone 3 Analysis

To comply with the air regulations, the Companies must install a circulating dry scrubber ("CDS") fabric filter at Tyrone 3. The capital costs associated with this control are summarized in Table 12. Table 13 summarizes the control's fixed and variable O&M costs, as well as the auxiliary power consumption. The capital and O&M savings that will be realized if Tyrone 3 is retired are summarized in Table 14. Table 15 summarizes the difference in revenue requirements between installing controls on Tyrone 3 and retiring/replacing its capacity. Retiring Tyrone 3 accelerates the need for additional capacity by one year (see Table 16). As a result, the capital costs associated with retiring/replacing capacity are higher than the capital costs associated with installing controls. However, this difference is more than offset by the production cost savings from retiring Tyrone 3. For this reason, installing controls on Tyrone 3 is not the least-cost option for complying with the air regulations. Tyrone 3 will be retired when the air regulations take effect.

Table 12 – Tyrone 3 Capital Costs for Environmental Controls

Equipment	2012	2013	2014	2015	Total
CDS Fabric Filter	-	-	15	30	45

Table 13 – Tyrone 3 Operational Impacts for Environmental Controls ($2011)

Equipment	Fixed O&M ($M)	Variable O&M ($/MWh)	Aux Power (MW)
CDS Fabric Filter	3.5	23.95	2

Table 14 – Tyrone 3 Retirement Savings ($M)

	Capital Savings	O&M Savings	Total Savings
PVRR	(22)	(3)	(26)

Table 15 – Tyrone 3 Revenue Requirements Comparison ($M)

	Production Cost	Capital	Total
PVRR Delta (Retire/replace capacity less install controls)	(49)	36	(13)

Table 16 – Tyrone 3 Expansion Plan Comparison

	Install Controls	Retire/Replace Capacity
2016		3x1C(1)
2017	3x1C(1)	
2018		
2019		
2020		
2021		
2022		
2023		
2024	3x1C(1)	3x1C(1)
2025		
2026		
2027		
2028		
2029		
2030	2x1C(1)	3x1C(1)
2031		
2032		
2033		
2034		
2035	2x1C(1)	
2036		2x1C(1)
2037		
2038		
2039	SCCT(1)	
2040		

Note: See Appendix C for definitions of expansion units.

4.2.2 Green River 3 Analysis

To comply with the air regulations, the Companies must install a CDS fabric filter at Green River 3. The capital costs associated with this control are summarized in Table 17. Table 18 summarizes the control's fixed and variable O&M costs, as well as the auxiliary power consumption. The capital and O&M savings that will be realized if Green River 3 is retired are summarized in Table 19. Table 20 summarizes the difference in revenue requirements between installing controls on Green River 3 and retiring/replacing its capacity. In this analysis, Tyrone 3 is assumed to be retired. Retiring Green River 3 results in changes to the resource expansion plan (see Table 21). As a result, the capital costs associated with retiring/replacing capacity are higher than the capital costs associated with installing controls. However, this difference is more than offset by the production cost savings from retiring Green River 3. For this reason, installing controls on Green River 3 is not the least-cost option for complying with the air regulations. Green River 3 will be retired when the air regulations take effect.

Table 17 – Green River 3 Capital Costs for Environmental Controls

Equipment	2012	2013	2014	2015	Total
CDS Fabric Filter	-	-	15	30	45

Table 18 – Green River 3 Operational Impacts for Environmental Controls ($2011)

Equipment	Fixed O&M ($M)	Variable O&M ($/MWh)	Aux Power (MW)
CDS Fabric Filter	3.5	23.95	2

Table 19 – Green River 3 Retirement Savings ($M)

	Capital Savings	O&M Savings	Total Savings
PVRR	(13)	(50)	(62)

Table 20 – Green River 3 Revenue Requirements Comparison ($M)

	Production Cost	Capital	Total
PVRR Delta (Retire/replace capacity less install controls)	(122)	42	(80)

Table 21 – Green River 3 Expansion Plan Comparison

	Install Controls	Retire/Replace Capacity
2016	3x1C(1)	2x1C(1)
2017		
2018		
2019		
2020		2x1C(1)
2021		
2022		
2023		
2024	3x1C(1)	
2025		3x1C(1)
2026		
2027		
2028		
2029		
2030	3x1C(1)	
2031		SCCT(1)
2032		
2033		3x1C(1)
2034		
2035		
2036	2x1C(1)	
2037		
2038		
2039		
2040		SCCT(1)

Note: See Appendix C for definitions of expansion units.

4.2.3 Brown 3 Analysis

To comply with the air regulations, the Companies must install a baghouse at Brown 3. The capital costs associated with the baghouse are summarized in Table 22. Table 23 summarizes the fixed and variable O&M costs, as well as the auxiliary power consumption. The capital and O&M savings that will be realized if Brown 3 is retired are summarized in Table 24. Table 25 summarizes the difference in revenue requirements between installing controls on Brown 3 and retiring/replacing its capacity. In this analysis, Tyrone 3 and Green River 3 are assumed to be retired. Retiring Brown 3 increases the need for additional capacity, resulting in a larger unit planned for 2016 (see Table 26). As a result, the capital costs associated with retiring/replacing capacity are higher than the capital costs associated with installing controls. In addition, the production cost increases from retiring Brown 3. For this reason, installing controls on Brown 3 is the least-cost option for complying with the air regulations.

Table 22 – Brown 3 Capital Costs for Environmental Controls

Equipment	2012	2013	2014	2015	Total
Baghouse	2	28	51	37	118

Table 23 – Brown 3 Operational Impacts for Environmental Controls ($2011)

Equipment	Fixed O&M ($M)	Variable O&M ($/MWh)	Aux Power (MW)
Baghouse	1.0	2.72	5

Table 24 – Brown 3 Retirement Savings ($M)

	Capital Savings	O&M Savings	Total Savings
PVRR	(100)	(174)	(274)

Table 25 – Brown 3 Revenue Requirements Comparison ($M)

	Production Cost	Capital	Total
PVRR Delta (Retire/replace capacity less install controls)	481	120	601

Table 26 – Brown 3 Expansion Plan Comparison

	Install Controls	Retire/Replace Capacity
2016	2x1C(1)	3x1C(1)
2017		
2018		
2019		
2020	2x1C(1)	3x1C(1)
2021		
2022		
2023		
2024		
2025	3x1C(1)	
2026		3x1C(1)
2027		
2028		
2029		
2030		
2031	SCCT(1)	
2032		
2033	3x1C(1)	3x1C(1)
2034		
2035		
2036		
2037		
2038		
2039		
2040	SCCT(1)	SCCT(1)

Note: See Appendix C for definitions of expansion units.

4.2.4 Cane Run 4 Analysis

To comply with the air regulations, the Companies must install a new FGD, SCR, baghouse, and SAM mitigation at Cane Run 4. The capital costs associated with these controls are summarized in Table 27. Table 28 summarizes the controls' fixed and variable O&M costs, as well as the auxiliary power consumption. The capital and O&M savings that will be realized if Cane Run 4 is retired are summarized in Table 29. Table 30 summarizes the difference in revenue requirements between installing controls on Cane Run 4 and retiring/replacing its capacity. In this analysis, Tyrone 3 and Green River 3 are assumed to be retired. Retiring Cane Run 4 increases the need for additional capacity, resulting in a larger unit planned for 2016 (see Table 31). However, the capital costs associated with retiring/replacing capacity are lower than the capital costs associated with installing controls. This difference more than offsets the production cost increase from retiring Cane Run 4. For this reason, installing controls on Cane Run 4 is not the least-cost option for complying with air regulations. Cane Run 4 will be retired when the air regulations take effect.

Table 27 – Cane Run 4 Capital Costs for Environmental Controls

Equipment	2011	2012	2013	2014	2015	Total
FGD	-	4	31	113	33	181
SCR	1	4	22	41	4	71
Baghouse	-	-	3	16	21	40
SAM Mitigation	-	-	-	-	3	3
Total	1	8	56	171	60	295

Table 28 – Cane Run 4 Operational Impacts for Environmental Controls ($2011)

Equipment	Fixed O&M ($M)	Variable O&M ($/MWh)	Aux Power (MW)
FGD	-	-	-
SCR	1.9	0.25	1
Baghouse	1.4	1.82	1
SAM Mitigation	0.2	0.99	-
Total	3.5	3.06	2

Table 29 – Cane Run 4 Retirement Savings ($M)

	Capital Savings	O&M Savings	Total Savings
PVRR	(47)	(140)	(187)

Table 30 – Cane Run 4 Revenue Requirements Comparison ($M)

	Production Cost	Capital	Total
PVRR Delta (Retire/replace capacity less install controls)	161	(249)	(88)

Table 31 – Cane Run 4 Expansion Plan Comparison

	Install Controls	Retire/Replace Capacity
2016	2x1C(1)	3x1C(1)
2017		
2018		
2019		
2020	2x1C(1)	
2021		
2022		2x1C(1)
2023		
2024		
2025	3x1C(1)	
2026		3x1C(1)
2027		
2028		
2029		
2030		
2031	SCCT(1)	
2032		SCCT(1)
2033	3x1C(1)	
2034		3x1C(1)
2035		
2036		
2037		
2038		
2039		
2040	SCCT(1)	

Note: See Appendix C for definitions of expansion units.

4.2.5 Cane Run 6 Analysis

To comply with the air regulations, the Companies must install a new FGD, SCR, baghouse, and SAM mitigation at Cane Run 6. The capital costs associated with these controls are summarized in Table 32. Table 33 summarizes the controls' fixed and variable O&M costs, as well as the auxiliary power consumption. The capital and O&M savings that will be realized if Cane Run 6 is retired are summarized in Table 34. Table 35 summarizes the difference in revenue requirements between installing controls on Cane Run 6 and retiring/replacing its capacity. In this analysis, Tyrone 3, Green River 3, and Cane Run 4 are assumed to be retired. Retiring Cane Run 6 increases and accelerates the need for additional capacity, resulting in a larger unit planned for 2020 instead of 2022 (see Table 36). Overall, the difference in PVRR between installing controls and retiring the unit is negligible ($8 million). If the Companies install controls on Cane Run 6 and the PVRR of a future expenditure not contemplated in this analysis exceeds $8 million, installing controls is not the least-cost option. Because the possibility of this occurring is considered high, the Companies do not recommend installing environmental controls on Cane Run 6. Cane Run 6 will be retired when the air regulations take effect.

Table 32 – Cane Run 6 Capital Costs for Environmental Controls

Equipment	2011	2012	2013	2014	2015	Total
FGD	-	4	39	159	41	242
SCR	1	13	32	47	5	97
Baghouse	-	-	4	22	28	55
SAM Mitigation	-	-	-	-	4	4
Total	1	17	75	228	78	399

Table 33 – Cane Run 6 Operational Impacts for Environmental Controls ($2011)

Equipment	Fixed O&M ($M)	Variable O&M ($/MWh)	Aux Power (MW)
FGD	-	-	-
SCR	2.4	0.19	1
Baghouse	1.9	1.73	2
SAM Mitigation	0.2	1.03	-
Total	4.5	2.95	3

Table 34 – Cane Run 6 Retirement Savings ($M)

	Capital Savings	O&M Savings	Total Savings
PVRR	(86)	(118)	(204)

Table 35 – Cane Run 6 Revenue Requirements Comparison ($M)

	Production Cost	Capital	Total
PVRR Delta (Retire/replace capacity less install controls)	279	(271)	8

Table 36 – Cane Run 6 Expansion Plan Comparison

	Install Controls	Retire/Replace Capacity
2016	3x1C(1)	3x1C(1)
2017		
2018		
2019		
2020		3x1C(1)
2021		
2022	2x1C(1)	
2023		
2024		
2025		
2026	3x1C(1)	3x1C(1)
2027		
2028		
2029		
2030		
2031		
2032	SCCT(1)	
2033		3x1C(1)
2034	3x1C(1)	
2035		
2036		
2037		
2038		
2039		
2040		SCCT(1)

Note: See Appendix C for definitions of expansion units.

4.2.6 Brown 1-2 Analysis

To comply with the air regulations, the Companies must install a combined baghouse at Brown 1 and 2, and SAM mitigation on each unit. The capital costs associated with the controls are summarized in Table 37. Table 38 summarizes the controls' fixed and variable O&M costs, as well as the auxiliary power consumption. The capital and O&M savings that will be realized if Brown 1 and 2 are retired are summarized in Table 39. Table 40 summarizes the difference in revenue requirements between installing controls on Brown 1 and 2 and retiring/replacing its capacity. In this analysis, Tyrone 3, Green River 3, Cane Run 4, and Cane Run 6 are assumed to be retired. Retiring Brown 1 and 2 accelerates the need for additional capacity, resulting in a second unit planned for 2018 instead of 2020 (see Table 41). However, the capital costs associated with retiring/replacing capacity are lower than the capital costs associated with installing controls. This difference is more than offset by the production cost increase from retiring Brown 1 and 2. For this reason, installing controls on Brown 1 and 2 is the least-cost option for complying with air regulations.

Table 37 – Brown 1-2 Capital Costs for Environmental Controls

Equipment	2011	2012	2013	2014	Total
Baghouse	5	64	92	57	219
SAM Mitigation	-	-	5	4	9
Total	5	64	97	61	228

Table 38 – Brown 1-2 Operational Impacts for Environmental Controls ($2011)

Equipment	Fixed O&M ($M)	Variable O&M ($/MWh)	Aux Power (MW)
Baghouse	1.2	7.83	3
SAM Mitigation	0.3	7.51	-
Total	1.5	15.34	3

Table 39 – Brown 1-2 Retirement Savings ($M)

	Capital Savings	O&M Savings	Total Savings
PVRR	(64)	(129)	(193)

Table 40 – Brown 1-2 Revenue Requirements Comparison ($M)

	Production Cost	Capital	Total
PVRR Delta (Retire/replace capacity less install controls)	279	(50)	228

Table 41 – Brown 1-2 Expansion Plan Comparison

	Install Controls	Retire/Replace Capacity
2016	3x1C(1)	3x1C(1)
2017		
2018		3x1C(1)
2019		
2020	3x1C(1)	
2021		
2022		
2023		
2024		3x1C(1)
2025		
2026	3x1C(1)	
2027		
2028		
2029		
2030		
2031		3x1C(1)
2032		
2033	3x1C(1)	
2034		
2035		
2036		
2037		SCCT(1)
2038		
2039		SCCT(1)
2040	SCCT(1)	

Note: See Appendix C for definitions of expansion units.

4.2.7 Cane Run 5 Analysis

To comply with the air regulations, the Companies must install a new FGD, SCR, baghouse, and SAM mitigation at Cane Run 5. The capital costs associated with these controls are summarized in Table 42. Table 43 summarizes the controls' fixed and variable O&M costs, as well as the auxiliary power consumption. The capital and O&M savings that will be realized if Cane Run 5 is retired are summarized in Table 44. Table 45 summarizes the difference in revenue requirements between installing controls on Cane Run 5 and retiring/replacing its capacity. In this analysis, Tyrone 3, Green River 3, Cane Run 4, and Cane Run 6 are assumed to be retired. Retiring Cane Run 5 accelerates the need for additional capacity, resulting in a second unit planned for 2019 instead of 2020 (see Table 46). However, the capital costs associated with retiring/replacing capacity are lower than the capital costs associated with installing controls. This difference more than offsets the production cost increase from retiring Cane Run 5. For this reason, installing controls on Cane Run 5 is not the least-cost option for complying with air regulations. Cane Run 5 will be retired when the air regulations take effect.

Table 42 – Cane Run 5 Capital Costs for Environmental Controls

Equipment	2011	2012	2013	2014	2015	Total
FGD	-	4	32	124	30	190
SCR	1	4	26	41	4	75
Baghouse	-	-	3	17	22	42
SAM Mitigation	-	-	-	-	3	3
Total	1	7	61	182	59	310

Table 43 – Cane Run 5 Operational Impacts for Environmental Controls ($2011)

Equipment	Fixed O&M ($M)	Variable O&M ($/MWh)	Aux Power (MW)
FGD	-	-	-
SCR	2.0	0.31	1
Baghouse	1.5	1.74	1
SAM Mitigation	0.2	1.00	-
Total	3.7	3.05	2

Table 44 – Cane Run 5 Retirement Savings ($M)

	Capital Savings	O&M Savings	Total Savings
PVRR	(51)	(149)	(200)

Table 45 – Cane Run 5 Revenue Requirements Comparison ($M)

	Production Cost	Capital	Total
PVRR Delta (Retire/replace capacity less install controls)	143	(201)	(58)

Table 46 – Cane Run 5 Expansion Plan Comparison

	Install Controls	Retire/Replace Capacity
2016	3x1C(1)	3x1C(1)
2017		
2018		
2019		3x1C(1)
2020	3x1C(1)	
2021		
2022		
2023		
2024		
2025		3x1C(1)
2026	3x1C(1)	
2027		
2028		
2029		
2030		
2031		2x1C(1)
2032		
2033	3x1C(1)	
2034		
2035		
2036		2x1C(1)
2037		
2038		
2039		
2040	SCCT(1)	

Note: See Appendix C for definitions of expansion units.

4.2.8 Ghent 3 Analysis

To comply with the air regulations, the Companies must install a baghouse and SAM mitigation/economizer modifications at Ghent 3. The capital costs associated with the controls are summarized in Table 47. Table 48 summarizes the controls' fixed and variable O&M costs, as well as the auxiliary power consumption. The capital and O&M savings that will be realized if Ghent 3 is retired are summarized in Table 49. Table 50 summarizes the difference in revenue requirements between installing controls on Ghent 3 and retiring/replacing its capacity. In this analysis, Tyrone 3, Green River 3, and Cane Run 4-6 are assumed to be retired. Retiring Ghent 3 increases the need for additional capacity, resulting in an additional unit planned for 2016 (see Table 51). As a result, the capital costs associated with retiring/replacing capacity are higher than the capital costs associated with installing controls. In addition, the production cost increases from retiring Ghent 3. For this reason, installing controls on Ghent 3 is the least-cost option for complying with the air regulations.

Table 47 – Ghent 3 Capital Costs for Environmental Controls

Equipment	Pre-2011	2011	2012	2013	2014	2015	2016	Total
Baghouse	-	-	-	38	56	84	4	182
SAM Mitigation/Economizer Modifications	0.1	1	5	10	0.4	-	-	16
Total	0.1	1	5	48	56	84	4	199

Table 48 – Ghent 3 Operational Impacts for Environmental Controls ($2011)

Equipment	Fixed O&M ($M)	Variable O&M ($/MWh)	Aux Power (MW)
Baghouse	1.2	3.30	6
SAM Mitigation/Economizer Modifications	-	-	-
Total	1.2	3.30	6

Table 49 – Ghent 3 Retirement Savings ($M)

	Capital Savings	O&M Savings	Total Savings
PVRR	(210)	(145)	(355)

Table 50 – Ghent 3 Revenue Requirements Comparison ($M)

	Production Cost	Capital	Total
PVRR Delta (Retire/replace capacity less install controls)	832	82	914

Table 51 – Ghent 3 Expansion Plan Comparison

	Install Controls	Retire/Replace Capacity
2016	3x1C(1)	3x1C(1), 2x1C(1)
2017		
2018		
2019	3x1C(1)	
2020		3x1C(1)
2021		
2022		
2023		
2024		
2025	3x1C(1)	
2026		3x1C(1)
2027		
2028		
2029		
2030		
2031	2x1C(1)	
2032		
2033		3x1C(1)
2034		
2035		
2036	2x1C(1)	
2037		
2038		
2039		
2040		SCCT(1)

Note: See Appendix C for definitions of expansion units.

4.2.9 Ghent 1 Analysis

To comply with the air regulations, the Companies must install a baghouse and SAM mitigation/economizer modifications at Ghent 1. The capital costs associated with the controls are summarized in Table 52. Table 53 summarizes the controls' fixed and variable O&M costs, as well as the auxiliary power consumption. The capital and O&M savings that will be realized if Ghent 1 is retired are summarized in Table 54. Table 55 summarizes the difference in revenue requirements between installing controls on Ghent 1 and retiring/replacing its capacity. In this analysis, Tyrone 3, Green River 3, and Cane Run 4-6 are assumed to be retired. Retiring Ghent 1 increases the need for additional capacity, resulting in an additional unit planned for 2016 (see Table 56). As a result, the capital costs associated with retiring/replacing capacity are higher than the capital costs associated with installing controls. In addition, the production cost increases from retiring Ghent 1. For this reason, installing controls on Ghent 1 is the least-cost option for complying with the air regulations.

Table 52 – Ghent 1 Capital Costs for Environmental Controls

Equipment	Pre-2011	2011	2012	2013	2014	Total
Baghouse	-	1	46	62	39	148
SAM Mitigation/Economizer Modifications	0.2	1	5	5	6	17
Total	0.2	2	50	67	45	164

Table 53 – Ghent 1 Operational Impacts for Environmental Controls ($2011)

Equipment	Fixed O&M ($M)	Variable O&M ($/MWh)	Aux Power (MW)
Baghouse	1.2	2.84	6
SAM Mitigation/Economizer Modifications	-	-	-
Total	1.2	2.84	6

Table 54 – Ghent 1 Retirement Savings ($M)

	Capital Savings	O&M Savings	Total Savings
PVRR	(208)	(210)	(417)

Table 55 – Ghent 1 Revenue Requirements Comparison ($M)

	Production Cost	Capital	Total
PVRR Delta (Retire/replace capacity less install controls)	722	71	794

Table 56 – Ghent 1 Expansion Plan Comparison

	Install Controls	Retire/Replace Capacity
2016	3x1C(1)	3x1C(2)
2017		
2018		
2019	3x1C(1)	
2020		
2021		
2022		3x1C(1)
2023		
2024		
2025	3x1C(1)	
2026		
2027		
2028		3x1C(1)
2029		
2030		
2031	2x1C(1)	
2032		
2033		
2034		
2035		2x1C(1)
2036	2x1C(1)	
2037		
2038		
2039		
2040		SCCT(1)

Note: See Appendix C for definitions of expansion units.

4.2.10 Green River 4 Analysis

To comply with the air regulations, the Companies must install a CDS fabric filter at Green River 4. The capital costs associated with this control are summarized in Table 57. Table 58 summarizes the control's fixed and variable O&M costs, as well as the auxiliary power consumption. The capital and O&M savings that will be realized if Green River 4 is retired are summarized in Table 59. Table 60 summarizes the difference in revenue requirements between installing controls on Green River 4 and retiring/replacing its capacity. In this analysis, Tyrone 3, Green River 3, and Cane Run 4-6 are assumed to be retired. Retiring Green River 4 accelerates the need for additional capacity, resulting in a second unit planned for 2018 instead of 2019 (see Table 61). However, the capital costs associated with retiring/replacing capacity are lower than the capital costs associated with installing controls. In addition, retiring Green River 4 results in production cost savings. For this reason, installing controls on Green River 4 is not the least-cost option for complying with the air regulations. Green River 4 will be retired when the air regulations take effect.

Table 57 – Green River 4 Capital Costs for Environmental Controls

Equipment	2012	2013	2014	2015	Total
CDS Fabric Filter	-	-	21	45	66

Table 58 – Green River 4 Operational Impacts for Environmental Controls ($2011)

Equipment	Fixed O&M ($M)	Variable O&M ($/MWh)	Aux Power (MW)
CDS Fabric Filter	4.6	23.54	3

Table 59 – Green River 4 Retirement Savings ($M)

	Capital Savings	O&M Savings	Total Savings
PVRR	(18)	(100)	(118)

Table 60 – Green River 4 Revenue Requirements Comparison ($M)

	Production Cost	Capital	Total
PVRR Delta (Retire/replace capacity less install controls)	(101)	(9)	(110)

Table 61 – Green River 4 Expansion Plan Comparison

	Install Controls	Retire/Replace Capacity
2016	3x1C(1)	3x1C(1)
2017		
2018		3x1C(1)
2019	3x1C(1)	
2020		
2021		
2022		
2023		
2024		3x1C(1)
2025	3x1C(1)	
2026		
2027		
2028		
2029		
2030		
2031	2x1C(1)	3x1C(1)
2032		
2033		
2034		
2035		
2036	2x1C(1)	
2037		SCCT(1)
2038		
2039		SCCT(1)
2040		

Note: See Appendix C for definitions of expansion units.

4.2.11 Mill Creek 4 Analysis

To comply with the air regulations, the Companies must install a new FGD, baghouse, and SAM mitigation/economizer modifications at Mill Creek 4, as well as upgrade the existing SCR. The capital costs associated with these controls are summarized in Table 62. Table 63 summarizes the controls' fixed and variable O&M costs, as well as the auxiliary power consumption. The capital and O&M savings that will be realized if Mill Creek 4 is retired are summarized in Table 64. Table 65 summarizes the difference in revenue requirements between installing controls on Mill Creek 4 and retiring/replacing its capacity. In this analysis, Tyrone 3, Green River 3-4, and Cane Run 4-6 are assumed to be retired. Retiring Mill Creek 4 increases the need for additional capacity, resulting in an additional unit planned for 2016 (see Table 66). However, the capital costs associated with retiring/replacing capacity are lower than the capital costs associated with installing controls. This difference is more than offset by the production cost increase from retiring Mill Creek 4. For this reason, installing controls on Mill Creek 4 is the least-cost option for complying with air regulations.

Table 62 – Mill Creek 4 Capital Costs for Environmental Controls

Equipment	Pre-2011	2011	2012	2013	2014	2015	Total
FGD	-	4	71	88	44	12	218
SCR Upgrade	-	1	4	-	-	-	6
Baghouse	-	4	50	55	35	8	152
SAM Mitigation/Economizer Modifications	0.2	-	-	4	5	1	11
Total	0.2	9	125	146	84	21	386

Table 63 – Mill Creek 4 Operational Impacts for Environmental Controls ($2011)

Equipment	Fixed O&M ($M)	Variable O&M ($/MWh)	Aux Power (MW)
FGD	-	0.11	8
SCR Upgrade	-	-	-
Baghouse	1.4	2.76	3
SAM Mitigation/Economizer Modifications	0.04	1.25	-
Total	1.4	4.12	11

Table 64 – Mill Creek 4 Retirement Savings ($M)

	Capital Savings	O&M Savings	Total Savings
PVRR	(105)	(201)	(306)

Table 65 – Mill Creek 4 Revenue Requirements Comparison ($M)

	Production Cost	Capital	Total
PVRR Delta (Retire/replace capacity less install controls)	919	(60)	859

Table 66 – Mill Creek 4 Expansion Plan Comparison

	Install Controls	Retire/Replace Capacity
2016	3x1C(1)	3x1C(2)
2017		
2018	3x1C(1)	
2019		
2020		
2021		3x1C(1)
2022		
2023		
2024	3x1C(1)	
2025		
2026		
2027		
2028		3x1C(1)
2029		
2030		
2031	3x1C(1)	
2032		
2033		
2034		
2035		3x1C(1)
2036		
2037	SCCT(1)	
2038		
2039	SCCT(1)	
2040		

Note: See Appendix C for definitions of expansion units.

4.2.12 Trimble County 1 Analysis

To comply with the air regulations, the Companies must install a baghouse at Trimble County 1. The capital costs associated with the baghouse are summarized in Table 67. Table 68 summarizes the fixed and variable O&M costs, as well as the auxiliary power consumption. The capital and O&M savings that will be realized if Trimble County 1 is retired are summarized in Table 69. Table 70 summarizes the difference in revenue requirements between installing controls on Trimble County 1 and retiring/replacing its capacity. In this analysis, Tyrone 3, Green River 3-4, and Cane Run 4-6 are assumed to be retired. Retiring Trimble County 1 increases the need for additional capacity, resulting in an additional unit planned for 2016 (see Table 71). As a result, the capital costs associated with retiring/replacing capacity are higher than the capital costs associated with installing controls. In addition, the production cost increases from retiring Trimble County 1. For this reason, installing controls on Trimble County 1 is the least-cost option for complying with the air regulations.

Table 67 – Trimble County 1 Capital Costs for Environmental Controls

Equipment	2013	2014	2015	2016	Total
Baghouse	23	38	57	5	124

Table 68 – Trimble County 1 Operational Impacts for Environmental Controls ($2011)

Equipment	Fixed O&M ($M)	Variable O&M ($/MWh)	Aux Power (MW)
Baghouse	0.9	2.10	4

Table 69 – Trimble County 1 Retirement Savings ($M)

	Capital Savings	O&M Savings	Total Savings
PVRR	(71)	(203)	(274)

Table 70 – Trimble County 1 Revenue Requirements Comparison ($M)

	Production Cost	Capital	Total
PVRR Delta (Retire/replace capacity less install controls)	805	188	993

Table 71 – Trimble County 1 Expansion Plan Comparison

	Install Controls	Retire/Replace Capacity
2016	3x1C(1)	3x1C(2)
2017		
2018	3x1C(1)	
2019		
2020		
2021		
2022		3x1C(1)
2023		
2024	3x1C(1)	
2025		
2026		
2027		
2028		3x1C(1)
2029		
2030		
2031	3x1C(1)	
2032		
2033		
2034		
2035		2x1C(1)
2036		
2037	SCCT(1)	
2038		
2039	SCCT(1)	
2040		SCCT(1)

Note: See Appendix C for definitions of expansion units.

4.2.13 Ghent 4 Analysis

To comply with the air regulations, the Companies must install a baghouse and SAM mitigation/economizer modifications at Ghent 4. The capital costs associated with the controls are summarized in Table 72. Table 73 summarizes the controls' fixed and variable O&M costs, as well as the auxiliary power consumption. The capital and O&M savings that will be realized if Ghent 4 is retired are summarized in Table 74. Table 75 summarizes the difference in revenue requirements between installing controls on Ghent 4 and retiring/replacing its capacity. In this analysis, Tyrone 3, Green River 3-4, and Cane Run 4-6 are assumed to be retired. Retiring Ghent 4 increases the need for additional capacity, resulting in an additional unit planned for 2016 (see Table 76). As a result, the capital costs associated with retiring/replacing capacity are higher than the capital costs associated with installing controls. In addition, the production cost increases from retiring Ghent 4. For this reason, installing controls on Ghent 4 is the least-cost option for complying with the air regulations.

Table 72 – Ghent 4 Capital Costs for Environmental Controls

Equipment	Pre-2011	2011	2012	2013	2014	2015	2016	Total
Baghouse	-	-	-	30	52	78	9	169
SAM Mitigation/Economizer Modifications	0.2	1	4	5	6	-	-	17
Total	0.2	1	4	35	57	78	9	185

Table 73 – Ghent 4 Operational Impacts for Environmental Controls ($2011)

Equipment	Fixed O&M ($M)	Variable O&M ($/MWh)	Aux Power (MW)
Baghouse	1.2	2.93	6
SAM Mitigation/Economizer Modifications	-	-	-
Total	1.2	2.93	6

Table 74 – Ghent 4 Retirement Savings ($M)

	Capital Savings	O&M Savings	Total Savings
PVRR	(210)	(141)	(350)

Table 75 – Ghent 4 Revenue Requirements Comparison ($M)

	Production Cost	Capital	Total
PVRR Delta (Retire/replace capacity less install controls)	1,044	110	1,155

Table 76 – Ghent 4 Expansion Plan Comparison

	Install Controls	Retire/Replace Capacity
2016	3x1C(1)	3x1C(2)
2017		
2018	3x1C(1)	
2019		
2020		
2021		3x1C(1)
2022		
2023		
2024	3x1C(1)	
2025		
2026		
2027		
2028		3x1C(1)
2029		
2030		
2031	3x1C(1)	
2032		
2033		
2034		3x1C(1)
2035		
2036		
2037	SCCT(1)	
2038		
2039	SCCT(1)	
2040		

Note: See Appendix C for definitions of expansion units.

4.2.14 Mill Creek 3 Analysis

To comply with the air regulations, the Companies must install an FGD, baghouse, and SAM mitigation/economizer modifications at Mill Creek 3. The capital costs associated with the controls are summarized in Table 77. Table 78 summarizes the controls' fixed and variable O&M costs, as well as the auxiliary power consumption. The capital and O&M savings that will be realized if Mill Creek 3 is retired are summarized in Table 79. Table 80 summarizes the difference in revenue requirements between installing controls on Mill Creek 3 and retiring/replacing its capacity. In this analysis, Tyrone 3, Green River 3-4, and Cane Run 4-6 are assumed to be retired. Retiring Mill Creek 3 increases the need for additional capacity, resulting in an additional unit planned for 2016 (see Table 81). As a result, the capital costs associated with retiring/replacing capacity are higher than the capital costs associated with installing controls. In addition, the production cost increases from retiring Mill Creek 3. For this reason, installing controls on Mill Creek 3 is the least-cost option for complying with the air regulations.

Table 77 – Mill Creek 3 Capital Costs for Environmental Controls

Equipment	Pre-2011	2011	2012	2013	2014	2015	2016	Total
FGD	-	-	7	32	30	5	-	74
Baghouse	-	-	-	40	49	44	8	140
SAM Mitigation/Economizer Modifications	0.2	-	5	5	-	-	-	10
Total	0.2	-	18	110	109	54	8	225

Table 78 – Mill Creek 3 Operational Impacts for Environmental Controls ($2011)

Equipment	Fixed O&M ($M)	Variable O&M ($/MWh)	Aux Power (MW)
FGD	-	0.14	1
Baghouse	1.2	2.76	5
SAM Mitigation/Economizer Modifications	0.03	1.25	-
Total	1.3	4.16	6

Table 79 – Mill Creek 3 Retirement Savings ($M)

	Capital Savings	O&M Savings	Total Savings
PVRR	(86)	(201)	(287)

Table 80 – Mill Creek 3 Revenue Requirements Comparison ($M)

	Production Cost	Capital	Total
PVRR Delta (Retire/replace capacity less install controls)	696	60	756

Table 81 – Mill Creek 3 Expansion Plan Comparison

	Install Controls	Retire/Replace Capacity
2016	3x1C(1)	3x1C(2)
2017		
2018	3x1C(1)	
2019		
2020		
2021		
2022		3x1C(1)
2023		
2024	3x1C(1)	
2025		
2026		
2027		
2028		3x1C(1)
2029		
2030		
2031	3x1C(1)	
2032		
2033		
2034		
2035		2x1C(1)
2036		
2037	SCCT(1)	
2038		
2039	SCCT(1)	
2040		SCCT(1)

Note: See Appendix C for definitions of expansion units.

4.2.15 Ghent 2 Analysis

To comply with the air regulations, the Companies must install a baghouse and SAM mitigation at Ghent 2. The capital costs associated with the controls are summarized in Table 82. Table 83 summarizes the controls' fixed and variable O&M costs, as well as the auxiliary power consumption. The capital and O&M savings that will be realized if Ghent 2 is retired are summarized in Table 84. Table 85 summarizes the difference in revenue requirements between installing controls on Ghent 2 and retiring/replacing its capacity. In this analysis, Tyrone 3, Green River 3-4, and Cane Run 4-6 are assumed to be retired. Retiring Ghent 2 increases the need for additional capacity, resulting in an additional unit planned for 2016 (see Table 86). As a result, the capital costs associated with retiring/replacing capacity are higher than the capital costs associated with installing controls. In addition, the production cost increases from retiring Ghent 2. For this reason, installing controls on Ghent 2 is the least-cost option for complying with the air regulations.

Table 82 – Ghent 2 Capital Costs for Environmental Controls

Equipment	Pre-2011	2011	2012	2013	2014	2015	Total
Baghouse	-	-	30	48	72	7	157
SAM Mitigation	0.03	0.1	8	0.4	-	-	8
Total	0.03	0.1	37	48	72	7	165

Table 83 – Ghent 2 Operational Impacts for Environmental Controls ($2011)

Equipment	Fixed O&M ($M)	Variable O&M ($/MWh)	Aux Power (MW)
Baghouse	1.5	2.79	9
SAM Mitigation	0.1	0.37	-
Total	1.6	3.16	9

Table 84 – Ghent 2 Retirement Savings ($M)

	Capital Savings	O&M Savings	Total Savings
PVRR	(212)	(156)	(368)

Table 85 – Ghent 2 Revenue Requirements Comparison ($M)

	Production Cost	Capital	Total
PVRR Delta (Retire/replace capacity less install controls)	1,018	121	1,139

Table 86 – Ghent 2 Expansion Plan Comparison

	Install Controls	Retire/Replace Capacity
2016	3x1C(1)	3x1C(2)
2017		
2018	3x1C(1)	
2019		
2020		
2021		3x1C(1)
2022		
2023		
2024	3x1C(1)	
2025		
2026		
2027		
2028		3x1C(1)
2029		
2030		
2031	3x1C(1)	
2032		
2033		
2034		3x1C(1)
2035		
2036		
2037	SCCT(1)	
2038		
2039	SCCT(1)	
2040		

Note: See Appendix C for definitions of expansion units.

4.2.16 Mill Creek 1-2 Analysis

To comply with the air regulations, the Companies must install a new combined FGD on Mill Creek 1 and 2, as well as a baghouse on each unit. The capital costs associated with these controls are summarized in Table 87. Table 88 summarizes the controls' fixed and variable O&M costs, as well as the controls' auxiliary power consumption. The capital and O&M savings that will be realized if Mill Creek 1 and 2 are retired are summarized in Table 89. Table 90 summarizes the difference in revenue requirements between installing controls on Mill Creek 1 and 2 and retiring/replacing the capacity. In this analysis, Tyrone 3, Green River 3-4, and Cane Run 4-6 are assumed to be retired. Retiring Mill Creek 1 and 2 increases the need for additional capacity, resulting in an additional unit planned for 2016 (see Table 91). However, the capital costs associated with retiring/replacing capacity are lower than the capital costs associated with installing controls. This difference is more than offset by the production cost increase from retiring Mill Creek 1 and 2. For this reason, installing controls on Mill Creek 1 and 2 is the least-cost option for complying with air regulations.

Table 87 – Mill Creek 1-2 Capital Costs for Environmental Controls

Equipment	2012	2013	2014	2015	Total
Combined 1&2 FGD	50	105	109	94	359
Baghouse	27	84	99	98	307
Total	77	189	208	192	666

Table 88 – Mill Creek 1-2 Operational Impacts for Environmental Controls ($2011)

Equipment	Fixed O&M ($M)	Variable O&M ($/MWh)	Aux Power (MW)
Combined 1&2 FGD	(0.8)	0.08	-
Baghouse	2.7	7.84	7
Total	2.0	7.92	7

Table 89 – Mill Creek 1-2 Retirement Savings ($M)

	Capital Savings	O&M Savings	Total Savings
PVRR	(133)	(325)	(457)

Table 90 – Mill Creek 1-2 Revenue Requirements Comparison ($M)

	Production Cost	Capital	Total
PVRR Delta (Retire/replace capacity less install controls)	1,219	(197)	1,022

Table 91 – Mill Creek 1-2 Expansion Plan Comparison

	Install Controls	Retire/Replace Capacity
2016	3x1C(1)	3x1C(2)
2017		
2018	3x1C(1)	
2019		
2020		3x1C(1)
2021		
2022		
2023		
2024	3x1C(1)	
2025		
2026		2x1C(1)
2027		
2028		
2029		
2030		
2031	3x1C(1)	3x1C(1)
2032		
2033		
2034		
2035		
2036		
2037	SCCT(1)	SCCT(1)
2038		
2039	SCCT(1)	SCCT(1)
2040		

Note: See Appendix C for definitions of expansion units.

5.0 Conclusion

The differences in present value of revenue requirements ("PVRR") between (a) installing controls and (b) retiring and replacing capacity are summarized in Table 92 below. The least-cost plan for complying with the proposed environmental regulations includes installing additional environmental controls on the Brown, Ghent, Mill Creek, and Trimble County 1 coal units. Installing controls on the Green River, Tyrone, and Cane Run coal units is not cost-effective. As a result, these units will be retired when the regulations take effect.

Table 92 - PVRR of Installing Controls vs. Retiring and Replacing Capacity ($M, $2011)

Unit(s)	Install Controls (A)	Retire/Replace Capacity (B)	Difference (A)-(B)
Tyrone 3	33,153	33,140	(13)
Green River 3	33,140	33,060	(80)
Brown 3	33,060	33,661	601
Cane Run 4	33,060	32,972	(88)
Cane Run 6	32,972	32,980	8
Brown 1-2	32,980	33,208	228
Cane Run 5	32,980	32,921	(58)
Ghent 3	32,921	33,836	914
Ghent 1	32,921	33,715	794
Green River 4	32,921	32,811	(110)
Mill Creek 4	32,811	33,671	859
Trimble County 1	32,811	33,804	993
Ghent 4	32,811	33,966	1,155
Mill Creek 3	32,811	33,567	756
Ghent 2	32,811	33,950	1,139
Mill Creek 1-2	32,811	33,833	1,022

The costs of the projects in the least-cost compliance plan are summarized in Table 93. The total capital cost for KU is $1,058 million. The total capital cost for LG&E is $1,400 million.

Table 93 – Proposed Capital Costs

Company	Generating Unit	Capital ($M)
KU	Brown 1-2	228
KU	Brown 3	118
KU	Ghent 1	164
KU	Ghent 2	165
KU	Ghent 3	199
KU	Ghent 4	185
KU	**Total**	**1,058**
LG&E	Mill Creek 1 -2	666
LG&E	Mill Creek 3	225
LG&E	Mill Creek 4	386
LG&E	Trimble County 1	124
LG&E	**Total**	**1,400**

6.0 Appendix

6.1 Appendix A – Analysis Assumptions

- Study Period:
  30-year period for Production Cost impacts (2011-2040)
  30-year period for Capital Costs impacts (2011-2040)

- The Companies continue as regulated entities subject to the oversight of the Kentucky Public Service Commission and the Commission continues to require the Companies to implement least-cost strategies to the benefit of the native load ratepayers.

- The capital costs, O&M costs, and the costs of increased emissions (both NO_x and SO_2) associated with the addition of new environmental projects will be subject to recovery through the Environmental Cost Recovery mechanism.

- Fuel Forecast (Base Assumptions)
  Any and all fuel cost savings associated with serving native load will be returned to the ratepayers though the Fuel Adjustment Clause mechanism.

- Load Forecast is taken from the 2011 Integrated Resource Plan.

- Financial Assumptions:

LG&E/KU Discount Rate (%):	6.71 %
Federal Income Tax Rate (%)	38.90 %
Insurance Rate (%):	0.07 %
Property Tax Rate (%):	0.15 %
Percentage of Debt in Capital Structure (%):	46.52 %
Debt Interest Rate/Weighted Cost of Debt (%):	3.84 %
Desired Return on Rate base (%):	6.71 %

6.2 Appendix B – Capital Costs for Environmental Controls

Unit	Control Technology	Air Regulation Precipitating Need for Control	Total Capital ($M)
Brown 1-2	Baghouses SAM Mitigation	HAPs Rule HAPs Rule	219 9
Brown 3	Baghouse	HAPs Rule	80
Cane Run 4	FGD SCR Baghouse SAM Mitigation	NAAQS NAAQS HAPs Rule HAPs Rule	181 71 40 3
Cane Run 5	FGD SCR Baghouse SAM Mitigation	NAAQS NAAQS HAPs Rule HAPs Rule	190 75 42 3
Cane Run 6	FGD SCR Baghouse SAM Mitigation	NAAQS NAAQS HAPs Rule HAPs Rule	242 97 55 4
Ghent 1	Baghouse SAM Mitigation/Economizer Modifications	HAPs Rule HAPs Rule	148 17
Ghent 2	Baghouse SAM Mitigation	HAPs Rule HAPs Rule	157 8
Ghent 3	Baghouse SAM Mitigation/Economizer Modifications	HAPs Rule HAPs Rule	182 16
Ghent 4	Baghouse SAM Mitigation/Economizer Modifications	HAPs Rule HAPs Rule	169 17
Green River 3	CDS Fabric Filter	NAAQS/HAPs Rule	45
Green River 4	CDS Fabric Filter	NAAQS/HAPs Rule	66
Mill Creek 1-2	Combined 1&2 FGD[14] Baghouse	NAAQS HAPs Rule	359 307
Mill Creek 3	FGD Baghouse SAM Mitigation/Economizer Modifications	NAAQS HAPs Rule HAPs Rule	74 140 16
Mill Creek 4	FGD SCR Upgrade Baghouse SAM Mitigation/Economizer Modifications	NAAQS CATR HAPs Rule HAPs Rule	218 6 152 17
Trimble County 1	Baghouse	HAPs Rule	124
Tyrone 3	CDS Fabric Filter	NAAQS/HAPs Rule	45

[14] The least-cost compliance plan for Mill Creek 1-2 is to install one new FGD to be shared by Mill Creek 1 and 2.

6.3 Appendix C – Expansion Units

Table 94 – Resource Expansion Plan Key

3x1C	3x1 Combined Cycle Combustion Turbine	907 MW
2x1C	2x1 Combined Cycle Combustion Turbine	605 MW
SCCT	Simple Cycle Combustion Turbine	194 MW

Coal Combustion Residuals Plan for E.W. Brown Station

PPL companies

Generation Planning & Analysis
May 2011

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1.0 Executive Summary

Kentucky Utilities Company's ("KU's") E.W. Brown Generating Station ("Brown") produces three primary coal combustion residuals ("CCR"): bottom ash, fly ash, and gypsum. The ash is currently stored in Brown's Auxiliary Pond ("Aux Pond"). The gypsum is currently being used in the expansion of the Aux Pond but will start being stored in the Aux Pond in 2012. The Aux Pond is expected to reach full capacity in 2015, creating a need for additional CCR management solutions.

On June 21, 2010, the EPA issued a proposed ruling to establish federal guidelines for CCR storage. It is expected that the Main Pond will not meet the proposed regulations. Therefore, KU has stopped construction of the Main Pond and is proposing to construct a landfill in its place to be in service in 2014.

In developing Brown's revised CCR storage plan, five options were reviewed. Two options were determined to be infeasible under the anticipated environmental regulations. The three remaining options were further evaluated to determine the least cost plan. These options are summarized as follows:

- **Case A**: The first landfill option stops construction of the Main Pond Starter Dike immediately, completes the expansion of the Aux Pond to 900 feet by 2012, and converts the Main Pond to a dry landfill by 2014.
- **Case B:** The second landfill option continues the construction of the Main Pond Starter Dike, continues the expansion of the Aux Pond by 2014, and converts the Main Pond to a landfill by 2016.
- **Offsite Landfill**: The third option is for stopping all construction of onsite storage facilities immediately and for a contractor to haul away all CCR for storage in an offsite commercial landfill.

The least cost option for the long-term storage needs at Brown is the first landfill option (Case A) with an onsite landfill in service in 2014. The present value of revenue requirement ("PVRR") of this case is $23 million lower than the second onsite landfill option (Case B) and is $80 million lower than the offsite disposal option.

2.0 Background

The Brown station is located in Mercer County, Kentucky and comprises three coal-fired generating units and seven gas-fired combustion turbines. The total net summer capacity for the three coal units is 683 MW. A flue gas desulfurization ("FGD") system was commissioned in 2010 to control SO_2 emissions from the three coal units. Bottom ash and fly ash are produced as byproducts of burning coal and are currently stored in the Aux Pond. Gypsum is produced as a chemical byproduct of using limestone reagent to remove sulfur dioxide from flue gas with the FGD system. Brown's gypsum is currently being used in the Aux Pond expansion and will be stored in the Aux Pond until a new long-term option is available.

The original CCR storage plan at Brown included

- a phased expansion of the Main Pond and
- a phased construction of the Aux Pond for interim storage of CCR during the Main Pond expansion and for storage of bottom ash once the Main Pond was to be available.

Environmental cost recovery ("ECR") treatment for the first phase of Brown's on-site storage plan was approved by the Kentucky Public Service Commission ("Commission") on June 20, 2005, as Project 20 in Case No. 2004-00426. This phase included raising the elevation of Brown's Main Pond to 902 feet and raising the elevation of the Aux Pond to 880 feet. The second phase was approved on December 23, 2009, as Project 29 in Case No. 2009-00197, and included expanding the Aux Pond to an elevation of 900 feet and expanding the Main Pond to 912 feet.

The Main Pond was removed from service in September 2008 to facilitate construction of the approved Phase I elevation of 902 feet which was scheduled for completion in 2010. The Aux Pond was completed to the approved Phase I elevation of 880 feet in 2008 and has been accepting fly ash and bottom ash since its completion. The second phase of construction, designated Aux Pond elevation 900', is currently ongoing and will expand the Aux Pond to the final design elevation. This second phase commenced in June 2010 and was originally planned to reach completion in mid-2013.

On June 21, 2010, the EPA issued a proposed CCR ruling to establish federal guidelines for CCR storage. These new regulations are expected to result in the possible need to either discontinue the current plans for the Main Pond or to modify its design to comply with the proposed regulations. The specific impacts of the proposed regulations to Brown's CCR plan are detailed in Exhibit JNV-4. Given the potential new requirements, new alternatives for dry landfill disposal of Brown's CCR were developed. The evaluation of these options is discussed herein.

3.0 Process and Methodology

KU and Louisville Gas and Electric Company (collectively "the Companies") develop a least-reasonable-cost plan for meeting the CCR storage needs at each generating station based on the information available at the time of the planning, including information concerning applicable environmental requirements. The process of identifying the plan consists of the three following primary tasks which are performed by several departments within the Companies.

- Needs assessment
- Development of alternatives
- Comparison of alternatives

CCR storage needs are defined by comparing the available storage capacity to the forecast of CCR production. The Project Engineering department and the applicable generating station are responsible for providing an estimate of remaining capacity.

The planned life of the storage facilities is based on CCR production forecast, which is developed by Generation Planning for all stations as a function of the expected coal usage for each unit. The Companies compile information regarding the cost of generation for each unit (e.g., fuel, variable operating and maintenance ("O&M") expenses, and emission costs), a description of the generation capabilities of each unit (e.g., capacity, heat rate curve, commitment parameters, emission rates, availability schedules), a load forecast, the market price of electricity, and the volumetric ability (transfer capability) to access the market. All of this information is brought together in the PROSYM software, which is used to model the economic operation of the Companies' generating system.[1] The projected coal usage data provided by this model is checked for reasonableness by comparing the results to historical data.

The Project Engineering department develops alternatives for onsite CCR storage solutions and their associated costs. Any alternatives for offsite disposal such as beneficial reuse or offsite landfill disposal are provided by each generating station's staff and a CCR team focused on exploring alternatives for byproduct storage. The cash flows for selected options are summarized and provided to Generation Planning for evaluation.

The Generation Planning department evaluates the storage and disposal options received from Project Engineering to determine the PVRR associated with the capital expenditures and O&M expenses of each option. This analysis is performed using the Capital Expenditure Recovery module of the Strategist software model.[2]

4.0 Needs Assessment

As of April 2010, the remaining available capacity of the Aux Pond is 272 thousand cubic yards ("KCY").[3] Completion of the second phase of the Aux Pond is expected to increase its capacity by 1,095 KCY in December 2011. The Aux Pond's remaining capacity was estimated by forecasting the CCR production of ash and gypsum at Brown. The quantity of ash produced at Brown is estimated at a coal specification of 12% ash by weight of the total quantity of coal

[1] The PROSYM model has formed the foundation of prior analyses involving certificates of convenience and necessity for new generating plants, environmental cost recovery for pollution control equipment, and the fuel adjustment clause.

[2] Strategist is a proprietary resource planning computer model. The Capital Expenditure Recovery module is used to quantify the revenue requirements impact associated with capital projects.

[3] Current storage capacities are provided to Generation Planning by Project Engineering based on bathymetric surveys. Based on expected coal burn, Generation Planning forecasts that by the end of 2011, the remaining capacity of the Aux Pond will be 176 KCY, excluding the Phase II expansion.

used, or approximately 12 tons of ash per 100 tons of coal. Converting to volumetric measurement, assuming ash production consists of 80% fly ash and 20% bottom ash, approximately 11 cubic yards ("CY") of total ash is produced per 100 tons of coal. These values are based on Brown's switch to high-sulfur coal in 2011.

The chemical reaction by which gypsum is produced results in a net gypsum production of approximately 18% by weight of the total quantity of coal used,[4] or approximately 18 tons of gypsum per 100 tons of coal. Converting to volumetric measurement, approximately 15 CY of dry-stored gypsum is produced per 100 tons of coal.

Table 1 shows the forecasted CCR production for Brown. The relatively low gypsum production in 2011 is due to the expectation to burn low-sulfur coal through 2011 to conclude a low-sulfur fuel contract. The lower sulfur content results in less gypsum produced.

Table 2 shows the associated quantities of coal forecasted to be burned at Brown, and contains the historical quantities of coal burned as a comparison to the forecast. The forecasted generation and the resulting coal usage at Brown correspond to an average capacity factor of approximately 40 - 45% before the anticipated retirements in 2016 of the coal units at the Cane Run, Green River, and Tyrone stations. After these retirements, Brown's capacity factor is forecasted to increase to approximately 60 - 70%. Variances in load or unexpected outages could result in future CCR production variances and changes to the long-term CCR storage plan at Brown.

Table 1: CCR Production Forecast

CCR Production Forecast (KCY – wet storage)			
	Bottom Ash	**Fly Ash**	**Gypsum**
2011	26	106	87
2012	32	127	226
2013	35	139	248
2014	34	135	240
2015	35	138	246
2016	43	172	307
2017	46	184	327
2018	46	186	330
2019	45	180	320
2020	48	192	341

[4] Fuel specification assumptions include SO_2 content of approximately 5.85 lb/MMBtu and heat content of 22.4 MMBtu/ton.

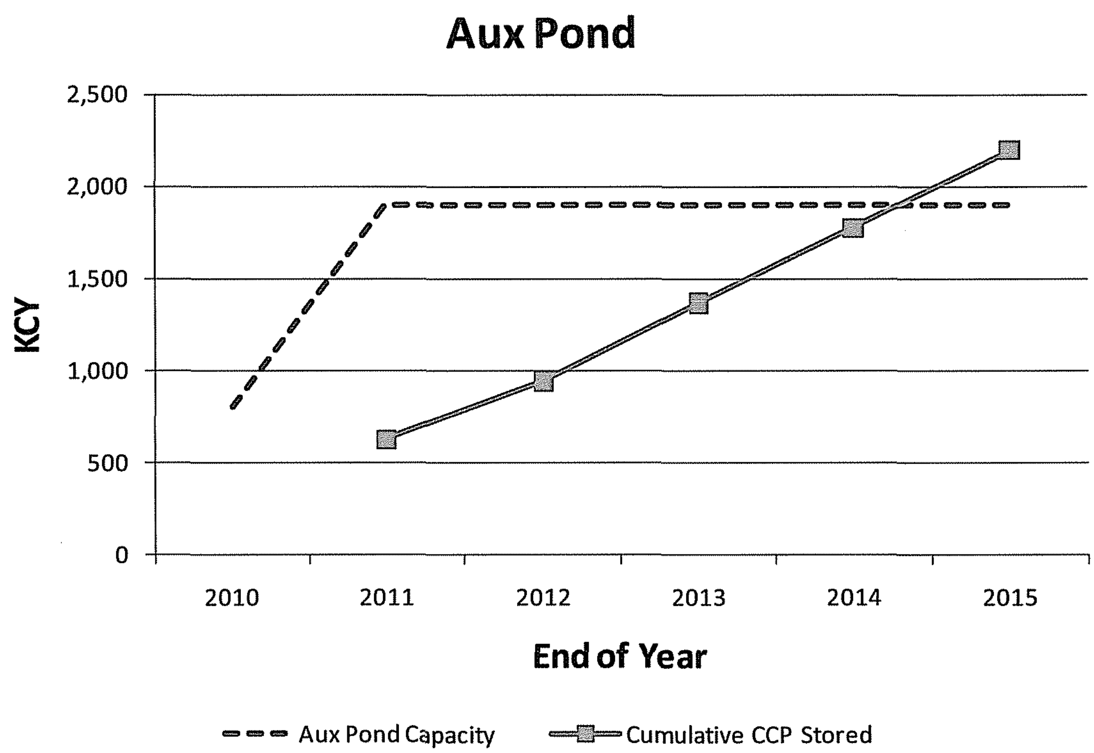
Table 2: Brown Coal Usage (Million Tons)

Brown Coal Usage *(M Tons)*	
Historical	
2006	1.5
2007	1.7
2008	1.8
2009	1.1
2010	1.3
Forecast	
2011	1.1
2012	1.3
2013	1.4
2014	1.3
2015	1.4
2016	1.7
2017	1.8
2018	1.8
2019	1.8
2020	1.9

Figure 1 demonstrates that the Aux Pond is expected to reach full capacity in 2015, with the following assumptions:

- The April 2011 forecast for CCR production
- Onsite beneficial reuse of all gypsum produced until May 2012
- No additional onsite capacity available at the Main Pond site
- No offsite CCR storage or reuse
- The Aux Pond Phase II expansion to 900' is completed in 2011

Figure 1: Aux Pond Capacity



5.0 Development of Alternatives

As a result of the EPA's proposed CCR Ruling, Project Engineering reevaluated long-term onsite CCR storage at Brown as discussed in Exhibit JNV-2. Of the four onsite options considered, two options were determined to be infeasible. Plans for the two remaining options for onsite landfills to replace the main pond were developed for further financial evaluation. In addition, an offsite alternative was compared to the onsite options. These three options are summarized as follows:

- **Case A** – Discontinue construction of the Main Pond Starter Dike, complete construction of the Aux Pond 900', and construct a dry landfill to be in service in 2014.
- **Case B** – Continue construction of the Main Pond Starter Dike and Aux Pond 900' per the original design. Once the CCR Ruling becomes effective, take the Main Pond out of service to construct a landfill over the Main Pond Starter Dike to be in service in 2016.
- **Off-Site Storage** - As an alternative to constructing onsite storage facilities, the offsite storage option represents the projected costs ($28/ton) of hiring a third-party contactor to haul all CCR produced offsite for disposal in a landfill.

6.0 Comparison of Alternatives

The Brown station has three viable alternatives for CCR disposal: Landfill Case A, Landfill Case B, and Offsite Storage. A PVRR evaluation of each of these alternatives was completed.

The capital and O&M costs for Cases A and B were provided by the Project Engineering group as detailed in Exhibit JNV-2. The O&M expenses for Offsite Storage are based on estimated costs for CCR disposal in an offsite landfill as shown in Table 3. Appendix 1 shows detailed assumptions for financial inputs and CCR characteristics. Appendix 2 shows the capital and O&M costs for each alternative.

Table 3: Off-site Disposal Cost

	$ per ton (2011)
Excavating and Loading	$1.82
Tipping Fee	$20.01
Hauling	$6.06
Total	$27.88

Table 4 shows that the PVRR for Case A is the least cost. The PVRR for Case B is $23 million greater than that of Case A. The PVRR for offsite storage is $80 million greater than that of the Case A. Appendix 3 shows the annual revenue requirements associated with each alternative.

Table 4: PVRR Comparison

2010 million $	Case A	Case B	Offsite Disposal
PVRR	130	153	250
Delta to Least Cost Case	Least Cost	23	80

7.0 Recommendation

The needs assessment demonstrates a need for additional CCR storage capacity at the Brown station by 2015. Analysis of the onsite and offsite storage options demonstrates that a completion of the Aux Pond expansion to elevation 900 feet that was part of the original 2005 ECR plan is advisable. And it is recommended to immediately begin converting the Main Pond to an onsite landfill to begin service in 2014 to allow for long-term CCR storage at Brown while complying with anticipated environmental regulations in a least cost manner.

The entire phased landfill Case A is more cost-effective than the delayed Main Pond conversion of Case B and offsite disposal. This plan will provide Brown with sufficient capacity to store CCR through 2031, with the potential to modify the future phases to accommodate changes in the CCR production forecast.

8.0 Appendices

8.1 Appendix 1 - Analysis Assumptions

Study Period: 2010-2031 for O&M costs impacts; 2010 through the book life of final project phase for capital costs

The revenue requirements associated with capital costs are determined via the Capital Expenditure and Recovery module of the Strategist production and capital costing software. To completely account for capital projects costs over their lifetime, the revenue requirements associated with new capital projects were extended through the end of their book life beyond the study period as needed.

Capital and O&M costs associated with the addition of new environmental projects will be recovered through the ECR mechanism.

Financial data

- Discount rate: 6.70%
- Income tax rate: 38.9%
- Insurance rate: 0.07%
- Property tax rate: 0.15 %
- Percentage of debt in capital structure: 47.13%
- Debt interest rate/weighted cost of debt: 3.76%
- Return on equity: 10.63%
- Aux Pond 900' capital book life: 17-20 years
- Landfill phase average book life, Case A: 11 years
- Landfill phase average book life, Case B: 9 years
- All CCR storage projects tax life: 20 years
- Annual capital escalation rate: 6%
- Annual O&M escalation rate: 3%
- Overhead: 3.5%

CCR Specifications Assumptions

- Coal % ash: 12%
- Bottom ash % of total ash: 20%
- CCR % moisture for hauling: 15%
- Density

Tons/CY	**Bottom Ash**	**Fly Ash**	**Gypsum**
Wet Storage	0.945	0.945	1.0125
Dry Storage	1.215	1.080	1.242

8.2 Appendix 2 - Annual Cash Flows

E.W. Brown Landfill - Case A

	Annual Cash Flows ($ thousands)									
	Capital						O&M			Total Cash Flows
	Aux Pond	Landfill				Total Capital	Gypsum Dewatering	Landfill	Total O&M	
		Phase 1	Phase 2	Phase 3	Final Cap					
2010	2,743	2,018	-	-	-	**4,761**	250	-	**250**	**5,011**
2011	8,393	5,869	-	-	-	**14,262**	515	-	**515**	**14,777**
2012	-	26,722	-	-	-	**26,722**	-	-	-	**26,722**
2013	-	24,064	-	-	-	**24,064**	-	-	-	**24,064**
2014	-	-	-	-	-	-	563	2,251	**2,814**	**2,814**
2015	-	-	-	-	-	-	580	2,319	**2,898**	**2,898**
2016	-	-	-	-	-	-	597	2,388	**2,985**	**2,985**
2017	-	-	-	-	-	-	615	2,460	**3,075**	**3,075**
2018	-	-	9,321	-	-	**9,321**	633	2,534	**3,167**	**12,488**
2019	-	-	899	-	-	**899**	652	2,610	**3,262**	**4,161**
2020	-	-	-	-	-	-	672	2,688	**3,360**	**3,360**
2021	-	-	-	-	-	-	692	2,768	**3,461**	**3,461**
2022	-	-	-	-	-	-	713	2,852	**3,564**	**3,564**
2023	-	-	-	18,434	-	**18,434**	734	2,937	**3,671**	**22,105**
2024	-	-	-	1,203	-	**1,203**	756	3,025	**3,781**	**4,985**
2025	-	-	-	-	-	-	779	3,116	**3,895**	**3,895**
2026	-	-	-	-	-	-	802	3,209	**4,012**	**4,012**
2027	-	-	-	-	-	-	826	3,306	**4,132**	**4,132**
2028	-	-	-	-	-	-	851	3,405	**4,256**	**4,256**
2029	-	-	-	-	-	-	877	3,507	**4,384**	**4,384**
2030	-	-	-	-	-	-	903	3,612	**4,515**	**4,515**
2031	-	-	-	-	2,714	**2,714**	930	3,721	**4,651**	**7,365**
Total	**11,136**	**58,674**	**10,220**	**19,637**	**2,714**	**102,382**	**13,942**	**52,706**	**66,648**	**169,029**

E.W. Brown Landfill - Case B

	Annual Cash Flows ($ thousands)									
	Capital						O&M			Total Cash Flows
	Aux Pond	Landfill				Total Capital	Gypsum Dewatering	Landfill	Total O&M	
		Phase 1	Phase 2	Phase 3	Final Cap					
2010	1,708	13,352	-	-	-	**15,059**	250	-	**250**	**15,309**
2011	2,907	-	-	-	-	**2,907**	515	-	**515**	**3,422**
2012	3,082	523	-	-	-	**3,605**	530	-	**530**	**4,136**
2013	4,499	6,287	-	-	-	**10,786**	546	-	**546**	**11,333**
2014	-	31,135	-	-	-	**31,135**	-	-	**-**	**31,135**
2015	-	31,387	-	-	-	**31,387**	-	-	**-**	**31,387**
2016	-	-	-	-	-	**-**	597	2,388	**2,985**	**2,985**
2017	-	-	-	-	-	**-**	615	2,460	**3,075**	**3,075**
2018	-	-	-	-	-	**-**	633	2,534	**3,167**	**3,167**
2019	-	-	-	-	-	**-**	652	2,610	**3,262**	**3,262**
2020	-	-	16,476	-	-	**16,476**	672	2,688	**3,360**	**19,836**
2021	-	-	1,132	-	-	**1,132**	692	2,768	**3,461**	**4,592**
2022	-	-	-	-	-	**-**	713	2,852	**3,564**	**3,564**
2023	-	-	-	-	-	**-**	734	2,937	**3,671**	**3,671**
2024	-	-	-	-	-	**-**	756	3,025	**3,781**	**3,781**
2025	-	-	-	24,727	-	**24,727**	779	3,116	**3,895**	**28,622**
2026	-	-	-	1,514	-	**1,514**	802	3,209	**4,012**	**5,526**
2027	-	-	-	-	-	**-**	826	3,306	**4,132**	**4,132**
2028	-	-	-	-	-	**-**	851	3,405	**4,256**	**4,256**
2029	-	-	-	-	-	**-**	877	3,507	**4,384**	**4,384**
2030	-	-	-	-	-	**-**	903	3,612	**4,515**	**4,515**
2031	-	-	-	-	2,280	**2,280**	930	3,721	**4,651**	**6,931**
Total	**12,196**	**82,684**	**17,608**	**26,242**	**2,280**	**141,009**	**13,876**	**48,137**	**62,013**	**203,022**

Off-Site Landfill Option

	Annual Cash Flows ($ thousands)	
	Capital	O&M
2010	-	3,960
2011	-	6,974
2012	-	12,750
2013	-	14,417
2014	-	14,385
2015	-	15,156
2016	-	19,487
2017	-	21,399
2018	-	22,261
2019	-	22,218
2020	-	24,363
2021	-	26,387
2022	-	27,047
2023	-	28,549
2024	-	30,280
2025	-	32,787
2026	-	32,151
2027	-	35,381
2028	-	36,194
2029	-	38,842
2030	-	38,218
2031	-	41,942
Total	**-**	**545,148**

8.3 Appendix 3 - Revenue Requirements

E.W. Brown Landfill - Case A

	Annual Revenue Requirements ($ thousands)									
	Capital						O&M			Total Revenue Requirements
	Aux Pond	Landfill Phase 1	Landfill Phase 2	Landfill Phase 3	Landfill Final Cap	Total Capital	Gypsum Dewatering	Landfill	Total O&M	
2010	244	179	-	-	-	**423**	250	-	**250**	**673**
2011	1,158	701	-	-	-	**1,859**	515	-	**515**	**2,374**
2012	1,680	3,076	-	-	-	**4,755**	-	-	-	**4,755**
2013	1,611	5,214	-	-	-	**6,825**	-	-	-	**6,825**
2014	1,544	11,226	-	-	-	**12,771**	563	2,251	**2,814**	**15,584**
2015	1,480	10,712	-	-	-	**12,192**	580	2,319	**2,898**	**15,090**
2016	1,418	10,210	-	-	-	**11,628**	597	2,388	**2,985**	**14,613**
2017	1,357	9,721	-	-	-	**11,078**	615	2,460	**3,075**	**14,152**
2018	1,298	9,242	828	-	-	**11,368**	633	2,534	**3,167**	**14,535**
2019	1,240	8,773	908	-	-	**10,922**	652	2,610	**3,262**	**14,183**
2020	1,183	8,313	1,960	-	-	**11,456**	672	2,688	**3,360**	**14,816**
2021	1,126	7,863	1,870	-	-	**10,858**	692	2,768	**3,461**	**14,319**
2022	1,068	7,413	1,782	-	-	**10,264**	713	2,852	**3,564**	**13,828**
2023	1,011	6,964	1,697	1,638	-	**11,309**	734	2,937	**3,671**	**14,981**
2024	953	6,432	1,613	1,745	-	**10,743**	756	3,025	**3,781**	**14,525**
2025	896	892	1,531	3,767	-	**7,087**	779	3,116	**3,895**	**10,982**
2026	839	787	1,451	3,594	-	**6,671**	802	3,209	**4,012**	**10,683**
2027	781	682	1,372	3,426	-	**6,262**	826	3,306	**4,132**	**10,394**
2028	724	577	1,294	3,261	-	**5,856**	851	3,405	**4,256**	**10,113**
2029	666	472	1,215	3,101	-	**5,455**	877	3,507	**4,384**	**9,839**
2030	582	367	1,123	2,943	-	**5,015**	903	3,612	**4,515**	**9,530**
2031	7	262	156	2,789	241	**3,456**	930	3,721	**4,651**	**8,107**
2032	0	158	138	2,638	513	**3,446**	-	-	-	**3,446**
2033	0	52	120	2,487	490	**3,149**	-	-	-	**3,149**
2034	-	-	101	2,336	467	**2,904**	-	-	-	**2,904**
2035	-	-	83	2,158	445	**2,685**	-	-	-	**2,685**
2036	-	-	64	301	423	**788**	-	-	-	**788**
2037	-	-	46	265	401	**713**	-	-	-	**713**
2038	-	-	28	230	380	**638**	-	-	-	**638**
2039	-	-	9	194	360	**563**	-	-	-	**563**
2040	-	-	-	159	339	**498**	-	-	-	**498**
2041	-	-	-	124	319	**442**	-	-	-	**442**
2042	-	-	-	88	294	**383**	-	-	-	**383**
2043	-	-	-	53	40	**93**	-	-	-	**93**
2044	-	-	-	18	35	**53**	-	-	-	**53**
2045	-	-	-	-	31	**31**	-	-	-	**31**
2046	-	-	-	-	26	**26**	-	-	-	**26**
2047	-	-	-	-	21	**21**	-	-	-	**21**
2048	-	-	-	-	17	**17**	-	-	-	**17**
2049	-	-	-	-	12	**12**	-	-	-	**12**
2050	-	-	-	-	7	**7**	-	-	-	**7**
2051	-	-	-	-	2	**2**	-	-	-	**2**
2010 PVRR	**13,635**	**66,297**	**7,916**	**11,022**	**894**	**99,763**	**6,620**	**23,549**	**30,169**	**129,932**

E.W. Brown Landfill - Case B

	Annual Revenue Requirements ($ thousands)									
	Capital						O&M			Total Revenue Requirements
	Aux Pond	Landfill Phase 1	Landfill Phase 2	Landfill Phase 3	Landfill Final Cap	Total Capital	Gypsum Dewatering	Landfill	Total O&M	
2010	152	1,186	-	-	-	**1,338**	250	-	**250**	**1,588**
2011	515	1,186	-	-	-	**1,702**	515	-	**515**	**2,217**
2012	965	1,233	-	-	-	**2,198**	530	-	**530**	**2,728**
2013	1,543	1,792	-	-	-	**3,334**	546	-	**546**	**3,881**
2014	1,810	4,558	-	-	-	**6,368**	-	-	**-**	**6,368**
2015	1,734	7,347	-	-	-	**9,082**	-	-	**-**	**9,082**
2016	1,661	17,585	-	-	-	**19,246**	597	2,388	**2,985**	**22,231**
2017	1,590	16,746	-	-	-	**18,336**	615	2,460	**3,075**	**21,410**
2018	1,521	15,925	-	-	-	**17,446**	633	2,534	**3,167**	**20,613**
2019	1,453	15,122	-	-	-	**16,575**	652	2,610	**3,262**	**19,837**
2020	1,387	14,334	1,464	-	-	**17,186**	672	2,688	**3,360**	**20,545**
2021	1,322	13,561	1,565	-	-	**16,448**	692	2,768	**3,461**	**19,908**
2022	1,256	12,802	3,717	-	-	**17,775**	713	2,852	**3,564**	**21,339**
2023	1,191	12,054	3,539	-	-	**16,785**	734	2,937	**3,671**	**20,456**
2024	1,126	11,214	3,366	-	-	**15,706**	756	3,025	**3,781**	**19,487**
2025	1,060	1,591	3,197	2,197	-	**8,045**	779	3,116	**3,895**	**11,940**
2026	995	1,439	3,030	2,332	-	**7,796**	802	3,209	**4,012**	**11,808**
2027	929	1,288	2,867	5,539	-	**10,624**	826	3,306	**4,132**	**14,756**
2028	864	1,136	2,706	5,276	-	**9,982**	851	3,405	**4,256**	**14,239**
2029	799	985	2,549	5,017	-	**9,349**	877	3,507	**4,384**	**13,733**
2030	705	833	2,371	4,765	-	**8,674**	903	3,612	**4,515**	**13,189**
2031	30	682	333	4,517	203	**5,764**	930	3,721	**4,651**	**10,415**
2032	14	530	301	4,273	475	**5,594**	-	-	**-**	**5,594**
2033	4	379	269	4,034	452	**5,138**	-	-	**-**	**5,138**
2034	-	227	238	3,799	430	**4,694**	-	-	**-**	**4,694**
2035	-	76	206	3,534	408	**4,224**	-	-	**-**	**4,224**
2036	-	-	174	496	387	**1,058**	-	-	**-**	**1,058**
2037	-	-	143	449	366	**958**	-	-	**-**	**958**
2038	-	-	111	402	346	**859**	-	-	**-**	**859**
2039	-	-	79	354	326	**759**	-	-	**-**	**759**
2040	-	-	48	307	303	**658**	-	-	**-**	**658**
2041	-	-	16	260	42	**317**	-	-	**-**	**317**
2042	-	-	-	213	38	**250**	-	-	**-**	**250**
2043	-	-	-	165	34	**199**	-	-	**-**	**199**
2044	-	-	-	118	30	**148**	-	-	**-**	**148**
2045	-	-	-	71	26	**97**	-	-	**-**	**97**
2046	-	-	-	24	22	**45**	-	-	**-**	**45**
2047	-	-	-	-	18	**18**	-	-	**-**	**18**
2048	-	-	-	-	14	**14**	-	-	**-**	**14**
2049	-	-	-	-	10	**10**	-	-	**-**	**10**
2050	-	-	-	-	6	**6**	-	-	**-**	**6**
2051	-	-	-	-	2	**2**	-	-	**-**	**2**
2010 PVRR	**13,939**	**86,740**	**11,993**	**12,931**	**750**	**126,353**	**6,682**	**20,136**	**26,818**	**153,171**

Off-Site Landfill Option

	Annual Revenue Requirements($ thousands)	
	Capital	**O&M**
2010	-	3,960
2011	-	6,974
2012	-	12,750
2013	-	14,417
2014	-	14,385
2015	-	15,156
2016	-	19,487
2017	-	21,399
2018	-	22,261
2019	-	22,218
2020	-	24,363
2021	-	26,387
2022	-	27,047
2023	-	28,549
2024	-	30,280
2025	-	32,787
2026	-	32,151
2027	-	35,381
2028	-	36,194
2029	-	38,842
2030	-	38,218
2031	-	41,942
PVRR	**-**	**249,968**

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF KENTUCKY UTILITIES COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	))))))	CASE NO. 2011-00161

DIRECT TESTIMONY OF
SHANNON L. CHARNAS
DIRECTOR, ACCOUNTING AND REGULATORY REPORTING
LG&E AND KU SERVICES COMPANY

Filed: June 1, 2011

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

A. My name is Shannon L. Charnas. I am the Director of Accounting and Regulatory Reporting for LG&E and KU Services Company, which provides services to Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively, "the Companies"). My business address is 220 West Main Street, Louisville, Kentucky, 40202. A statement of my education and work experience is attached to this testimony as Appendix A.

Q. Have you previously testified before this Commission?

A. Yes. I have previously testified before this Commission in numerous proceedings, including the Companies' most recent base rate cases (Case Nos. 2009-00548 (KU) and 2009-00549 (LG&E)) and environmental cost recovery compliance plan proceedings (Case Nos. 2009-00197 (KU) and 2009-00198 (LG&E)).

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain KU's reporting and accounting for the operation and maintenance expenses associated with the pollution control projects in KU's 2011 Environmental Compliance Plan ("2011 Plan"), to demonstrate that the environmental compliance costs KU proposes to recover through its surcharge are not already included in existing rates, and to discuss the accounting treatment of costs included in base rates when applicable.

<u>Recording and Tracking of Environmental Surcharge Expenses</u>

Q. Is KU seeking recovery of operation and maintenance expenses associated with some of the projects included in its proposed 2011 Plan?

A. Yes. KU is seeking recovery of operating and maintenance ("O&M") expenses for new Projects 34 and 35 and amended Project 29, which relate to various installations and modifications to existing equipment KU has proposed in order to comply with existing and proposed regulations. In Project 34, KU proposes to construct Particulate Matter Control Systems to serve all three of the units at the E.W. Brown Generating Station ("Brown"). As John N. Voyles explains in his testimony, each Particulate Matter Control System comprises a pulse-jet fabric filter ("baghouse") to capture particulate matter, a Powdered Activated Carbon ("PAC") injection system to capture mercury, and a lime injection system to protect the baghouses from the corrosive effects of sulfuric acid mist ("SAM").

KU proposes to recover the O&M costs of the Particulate Matter Control Systems through the environmental surcharge mechanism. All of these O&M costs will be incremental except those associated with the Brown Unit 3 SAM mitigation component of the unit's Particulate Matter Control System; Brown Unit 3 has a separate SAM mitigation system being installed, which the Commission approved as part of Project 28 in KU's 2009 ECR Plan. As discussed in the testimony of Robert M. Conroy, KU proposes to report the current SAM-sorbent-O&M expenses for Brown Unit 3 as part of the overall SAM-sorbent-O&M for the Particulate Matter Control Systems in Project 34.

One reason for this reporting approach, as Mr. Voyles explains in his testimony, is that, as a practical matter, it is very difficult to track separately the SAM sorbent being used by multiple environmental facilities related to different ECR projects at the same generating unit with reasonable certainty. The other reason for this reporting approach is that KU records all of a unit's SAM-sorbent costs in the same subaccount, regardless of which system on the unit consumes the sorbent. Therefore, it will not be possible to report with reasonable certainty separate SAM-sorbent-O&M costs for both projects.

KU is also proposing to recover the incremental O&M associated with Project 35 concerning the Particulate Matter Control Systems KU proposes to install to serve all units at the Ghent Generating Station ("Ghent"). There are already separate SAM mitigation systems in place at Units 1, 3, and 4, which the Commission approved as part of KU's 2006 Plan (Project 24). As discussed in the testimony of Mr. Conroy, KU proposes to report the SAM-sorbent-O&M expenses for Ghent Units 1, 3, and 4 as part of the overall SAM-sorbent-O&M for the Particulate Matter Control Systems in Project 35 for the same reasons cited above concerning SAM-sorbent-O&M cost reporting for Brown.

As the testimony of Mr. Voyles describes in detail, KU proposes to make modifications to Ghent Units 1, 3, and 4 to expand the operating range of the units at which their Selective Catalytic Reduction ("SCR") equipment can function to reduce nitrogen oxide emissions. KU is not requesting to recover O&M associated with these "turn-down" modifications, which modifications will be made to the generating units, not the SCRs themselves. As noted in the testimony of Mr. Voyles, the turn-down modifications included in Project 35 are not expected to change the O&M associated with the SCRs at Ghent.

KU is also seeking recovery of O&M expenses for amended Project 29, in which KU proposes to convert Brown's existing Main Ash Pond to a dry-storage landfill. (The Commission approved Project 29 in Case No. 2009-00197.) Although there was no O&M associated with the Main Ash Pond, there will be O&M associated with the landfill after it goes into service.

These projects are discussed in detail in Mr. Voyles's testimony, and the estimated O&M costs are shown on page 2 of Exhibit JNV-1.

Q. How will KU identify the O&M expenses associated with these projects in its 2011 Plan?

A. KU's accounting system permits the tracking of costs in accordance with the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts. KU intends to use FERC Account No. 502, Steam Expenses – Operation, 506, Miscellaneous Steam Power Expenses, and 512, Maintenance of Boiler Plant, to identify and track the O&M expenses associated with these projects. KU will use subaccounts to track specific expenses and location codes to track expenses by unit.

Q. Has similar accounting proven to be successful in previous ECR cases?

A. Yes, tracking the costs using this accounting methodology has proven to be successful in the past. The costs in these accounts will be clearly detailed in the Environmental Surcharge Monthly Report, ES Form 2.50. The testimony of Mr. Conroy presents the proposed Environmental Surcharge Monthly Reports, including ES Form 2.50 and provides a detailed description of each form.

Q. What book depreciation rates will be used in the calculation of the depreciation expense for the new capital projects?

A. The book depreciation rates to be used for the new capital projects at all existing units will be the existing depreciation rates for that group of assets. The Commission approved these rates, which are based on the Average Service Life methodology, in its February 5, 2009 Final Order in KU's 2008 base rate case, Case No. 2008-00251, which was consolidated with KU's most recent depreciation study case, Case No. 2007-00565.[1]

Q. What deferred income taxes are associated with pollution control facilities?

A. Deferred income taxes are recorded for all book-versus-tax temporary timing differences. The new capital projects are eligible for accelerated tax depreciation and amortization. These assets will generally fall into a 20-year Modified Accelerated Cost Recovery System life, or will be eligible for U.S. Tax Code Section 169 amortization over a five- or seven-year life.

Q. Please explain how property taxes associated with the new pollution control facilities are calculated.

A. Pollution control facilities in Kentucky are generally categorized as manufacturing machinery. This class of property is exempt from local property tax and is taxed at the state property tax rate of $0.15 per $100 of assessed value.

<u>Costs Not Already Included in Existing Base Rates</u>

Q. Are any of the capital expenditures for the new pollution control facilities in Projects 34 and 35 in the 2011 Plan already included in existing base rates?

A. No. The current base rates were determined to be fair, just, and reasonable by the Commission in its Order issued July 30, 2010, in Case No. 2009-00548. In

[1] *In the Matter of: Application of Kentucky Utilities Company to File Depreciation Study*, Case No. 2007-00565, and *In the Matter of: Application of Kentucky Utilities Company for an Adjustment of Electric Base Rates*, Case No. 2008-00251, Order at 10 (Feb, 5, 2009).

making that determination, the Commission evaluated the reasonableness of KU's regulated return from Kentucky jurisdictional operations using the twelve-month period ending October 31, 2009, as the test period, adjusted for known and measurable changes. No capital expenditures for the new pollution control facilities identified in the 2011 Plan were incurred by KU during or prior to the twelve-month period ending October 31, 2009, or included as adjustments thereto, for which KU is seeking recovery in this case.

Q. Are any of the O&M expenses associated with the new pollution control facilities in Projects 34 and 35 in the 2011 Plan already included in existing base rates?

A. No, there are no O&M expenses for which KU is seeking recovery in this filing associated with the facilities in Projects 34 and 35 that are already in existing base rates. Recovery of O&M expenses for the pollution control facilities in Projects 34 and 35 will be incremental O&M expenses to any O&M expenses in base rates.

The SCRs at Ghent Units 1, 3 and 4, which are the subject of Project 35 in the 2011 Plan, were in operation during the test period in the last rate case; however, as discussed in the testimony of Mr. Voyles, the proposed turn-down modifications to the generating units are not expected to change the level of O&M associated with the SCRs. Accordingly, KU is not proposing to seek recovery of O&M associated with these three Ghent SCRs through the environmental surcharge in this case. The capital and operating costs of the SCRs will remain base-rate items.

Q. Will the installation of the new pollution control facilities in KU's 2011 ECR Plan replace or cause existing facilities to be removed from service?

A. Yes. The addition of the Particulate Matter Control Systems included in Projects 34 and 35 will result in the removal from service of some existing assets. The exact amount cannot be readily identified with reasonable accuracy until construction is complete. According to Mr. Voyles, the amount is expected to be minimal and to include assets such as miscellaneous utility and ductwork connections.

The process for accounting for and removal of such costs from the environmental surcharge, previously approved by the Commission in prior proceedings, will continue to be used by KU with the approval of the 2011 Plan. As existing equipment is removed or replaced, labor associated with the removal will be charged to Retirement Work in Progress ("RWIP"). Upon completion of the projects, the book value of the assets replaced will be removed from the Plant in Service Account. Accumulated Depreciation and all associated RWIP charges will be removed from the Reserve for Accumulated Depreciation account and the monthly ECR filings will be adjusted to reflect the retirements. As described in Mr. Conroy's testimony, when appropriate, KU will adjust the monthly ECR filings to reflect asset retirements in the Environmental Surcharge Monthly Report, ES Form 2.10, in conformity with prior Commission orders and consistent with KU's current practice.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **Shannon L. Charnas**, being duly sworn, deposes and says that she is Director, Accounting and Regulatory Reporting for LG&E and KU Services Company, and that she has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of her information, knowledge and belief.

Shannon L Charnas
Shannon L. Charnas

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 27th day of May 2011.

Kimberly M Walters (SEAL)
Notary Public

My Commission Expires:

9/11/2012

APPENDIX A

Shannon L. Charnas
Director, Accounting and Regulatory Reporting
LG&E and KU Services Company
220 West Main Street
Louisville, KY 40202
(502) 627-4978

Professional Memberships
American Institute of Certified Public Accountants
Kentucky Society of Certified Public Accountants

Education
University of Louisville, Masters of Business Administration, 2000
University of Wisconsin Oshkosh, Bachelor of Business Administration with Majors in Accounting and Management Information Systems, 1993
Certified Public Accountant, Kentucky, 1995

Previous Positions

E.ON U.S.
- 2001 (Mar) - 2005 (Feb) - Manager, Finance & Budgeting - Energy Services
- 1999 (Sept) - 2001 (Apr) - Senior Budget Analyst
- 1995 (Aug) - 1999 (Sept) - Accounting Analyst, various positions

Arthur Andersen LLP

- 1995 – Senior Auditor
- 1993 – 1994 – Audit Staff

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF KENTUCKY UTILITIES COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	)	CASE NO. 2011-00161

DIRECT TESTIMONY OF
ROBERT M. CONROY
DIRECTOR, RATES
LG&E AND KU SERVICES COMPANY

Filed: June 1, 2011

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

A. My name is Robert M. Conroy. I am the Director, Rates for LG&E and KU Services Company, which provides services to Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively "the Companies"). My business address is 220 West Main Street, Louisville, Kentucky, 40202. A complete statement of my education and work experience is attached to this testimony as Appendix A.

Q. Have you previously testified before this Commission?

A. Yes. I have previously testified before this Commission in numerous proceedings, including the Companies' most recent base rate cases (Case Nos. 2009-00548 (KU) and 2009-00549 (LG&E)) and environmental cost recovery compliance plan proceedings (Case Nos. 2009-00197 (KU) and 2009-00198 (LG&E)).

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring five exhibits, identified as Exhibits RMC-1, RMC-2 RMC-3, RMC-4, and RMC-5. These exhibits are:

Exhibit RMC-1 Proposed ECR Tariff

Exhibit RMC-2 Proposed ECR Tariff - Redline

Exhibit RMC-3 Current KU Environmental Surcharge Monthly Reports

Exhibit RMC-4 Proposed KU Environmental Surcharge Monthly Reports

Exhibit RMC-5 2011 ECR Plan Customer Bill Impact

Q. What is the purpose of your testimony?

A. My testimony addresses how the environmental surcharge under KU's Rate Schedule Environmental Cost Recovery Surcharge ("ECR") tariff will be calculated to include the costs incurred in connection with the new pollution control projects in KU's 2011 Environmental Compliance Plan ("2011 Plan").

Q. Is KU proposing any changes to its Environmental Cost Recovery Surcharge tariff?

A. Yes. KU is proposing some minor clarifying changes to its Environmental Cost Recovery Surcharge tariff. KU is filing its Environmental Cost Recovery Surcharge tariff for the purpose of obtaining the Commission's approval of the recovery of the costs of the 2011 Environmental Compliance Plan by the proposed assessment through this tariff. The proposed ECR Tariff is attached as Exhibit RMC-1 and a redline version comparing the proposed ECR Tariff to the existing tariff is attached as Exhibit RMC-2. The ECR tariff has an issue date of June 1, 2011, and is proposed to be effective on December 1, 2011. Therefore, bills issued on and after January 31, 2012, will reflect the revised environmental surcharge beginning with the expense month of December 2011.

Q. Will the methodologies for calculating the environmental surcharge change if the Commission approves recovery of KU's 2011 Plan?

A. No. KU will use the currently approved methodologies for calculating the environmental surcharge as specified by the Commission in Case Nos. 2000-439 ("2001 Plan"), [1] 2002-00146 ("2003 Plan"),[2] 2004-00426 ("2005 Plan"),[3] 2006-

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[1] *In the Matter of: The Application of Kentucky Utilities Company for Approval of an Amended Compliance Plan for Purposes of Recovering the Costs of New and Additional Pollution Control Facilities and to Amend Its Environmental Cost Recovery Surcharge Tariff.*

[2] *In the Matter of: The Application of Kentucky Utilities Company for Approval of Its 2002 Compliance Plan for Recovery by Environmental Surcharge.*

[3] *In the Matter of: The Application of Kentucky Utilities Company for a Certificate of Public Convenience and Necessity to Construct Flue Gas Desulfurization Systems and Approval of Its 2004 Compliance Plan for Recovery by Environmental Surcharge.*

00206 ("2006 Plan"),[4] and 2009-00197 ("2009 Plan"),[5] as well as orders issued in previous review cases. The calculation of the monthly Environmental Surcharge billing factor will continue to consolidate the 2005 Plan, 2006 Plan, and 2009 Plan and if approved, the proposed 2011 Plan.

Q. Will the monthly reporting forms used for calculating the environmental surcharge change if the Commission approves recovery of KU's 2011 Plan?

A. Yes. KU is proposing to revise several of its monthly reporting forms to reflect the recovery of the costs associated with the 2011 Plan. Exhibit RMC-3 contains the forms KU currently uses when filing its monthly environmental surcharge report. Exhibit RMC-4 shows the illustrative monthly environmental surcharge report forms KU is proposing in this case.

Q. Please describe the modifications that KU is proposing as a result of the 2011 Plan.

A. The calculation of the monthly billing factor for recovery of the cost of KU's 2011 Plan will be consistent with the methodology approved by the Commission in Case No. 2009-00310 and used to calculate the recovery of the cost of KU's current Environmental Compliance Plans.[6] ES Form 1.00 will continue to show the calculation of the Jurisdictional Environmental Surcharge Billing Factor using the same methodology previously approved by the Commission.

[4] *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 and Approval of Its 2006 Compliance Plan for Recovery by Environmental Surcharge.*

[5] *In the Matter of: The Application of Kentucky Utilities Company for Certificates of Public Convenience and Necessity and Approval of Its 2009 Compliance Plan for Recovery by Environmental Surcharge.*

[6] *In the Matter of: An Examination by the Public Service Commission of the Environmental Surcharge Mechanism of Kentucky Utilities Company for the Two-Year Billing Period Ending April 30, 2009* (Case No. 2009-00310) Order, December 2, 2009.

Determination of the Environmental Compliance Rate Base is based on combining all ECR-approved expenditures and calculating the rate base according to the methodologies ordered in the previous Compliance Plan cases.

The plant, construction work in progress, and depreciation expenses for the 2005, 2006, and 2009 Plans are currently reported on ES Form 2.10. This form is being expanded to include the 2011 Plan projects for which KU is seeking cost recovery. With the elimination of the 2001 and 2003 Plans in Case No. 2009-00548,[7] the projects associated with those Plans are being removed from the form.

The pollution control equipment operation and maintenance ("O&M") expenses for the 2005, 2006, and 2009 Plans are currently reported on ES Form 2.50. This form is being expanded to include the incremental O&M expenses associated with the 2011 Plan projects. In addition, ES Form 2.50 is being modified under the 2009 Plan for Project 29 to include the O&M accounts for the Brown Landfill. The projects for the 2001 and 2003 Plans are being removed from the form.

KU has added a line to ES Form 2.00 to include the actual monthly expense for the SO_2 emission allowance expense associated with Trimble County Unit 2 not included on ES Form 2.31. Moreover, KU has proposed to remove two line items that are no longer used from ES Form 2.00. The Monthly Insurance Expense and Monthly Surcharge Consultant Fee are not being recovered through the ECR mechanism and have been removed from the Determination of Pollution Control Operating Expenses section.

[7] The Commission's final order in KU's most recent rate case approved the terms of a Stipulation agreed to by all of the parties to the action, except the Attorney General. The Stipulation stated that all of the costs associated with the 2001 and 2003 Plans are to be recovered in rate base and removed from the Company's monthly environmental surcharge filings. *In the Matter of: Application of Kentucky Utilities Company for a Adjustment of Its Base Rates* (Case No. 2009-00548) Order, July 30, 2010.

Q. Please describe KU's proposal concerning the reporting of sulfuric acid mist ("SAM") sorbent O&M expenses currently being recovered through the environmental surcharge mechanism.

A. KU currently recovers through the environmental surcharge mechanism as part of Project 24 (2006 Plan) the SAM-sorbent-O&M costs related to the SAM mitigation systems installed on Ghent Units 1, 3, and 4. Also, the Commission approved as part of Project 28 (2009 Plan) a SAM-sorbent system to be installed on Brown Unit 3 as part of the unit's selective catalytic reduction equipment, which KU plans to install in the near future.

As described in the testimony of John N. Voyles, KU proposes to install Particulate Matter Control Systems to serve all of the Ghent and Brown units. Each Particulate Matter Control System comprises a pulse-jet fabric filter ("baghouse") to capture particulate matter, a Powdered Activated Carbon ("PAC") injection system to capture mercury, and a lime injection system to protect the baghouses from the corrosive effects of SAM. Because the other O&M components of the Particulate Matter Control Systems (including consumables like PAC) will be reported as part of Project 34 for Brown and Project 35 for Ghent, KU proposes to report the SAM-sorbent-O&M costs of the SAM mitigation systems for Brown and Ghent as part of the SAM-sorbent-O&M costs associated with Projects 34 and 35. In other words, instead of reporting the SAM-sorbent-O&M costs for Ghent Units 1, 3, and 4 under the 2006 Plan on ES Form 2.50, KU proposes to report them under the 2011 Plan on ES Form 2.50; likewise, instead of reporting the SAM-sorbent-O&M costs for Brown Unit 3 under the 2009 Plan on ES Form 2.50, KU proposes to report them under the 2011 Plan on ES Form 2.50.

KU proposes this kind of O&M cost reporting for SAM-sorbent costs for two reasons. First, as Mr. Voyles states in his testimony, as a practical matter, KU cannot track separately the SAM sorbent used for different environmental compliance projects at the same generating unit; all that is tracked is SAM sorbent consumed at the unit. Second, as Shannon L. Charnas explains in her testimony, each generating unit's SAM sorbent costs are recorded in the same subaccount, making it very difficult to determine with reasonable certainty how much SAM sorbent cost should be reported for each project.

To be clear, KU is not proposing to re-open or amend Project 24 or 28; rather, KU is merely proposing to report, on ES Form 2.50 in the monthly ECR filings, the SAM-sorbent-O&M costs as parts of different projects (i.e., Projects 34 and 35) to comport with practical necessity and to provide clearer reporting to the Commission.

Q. **Has KU estimated the impact of the new projects on the Environmental Cost Recovery Surcharge?**

A. Yes. The table below shows the estimated annual impact on Total E(m), Jurisdictional E(m), and the incremental billing factor associated with the projects contained in the 2011 Plan. As shown in the table, the estimated impact on a customer is an increase of 1.5% initially in 2012 and increasing to a maximum of 12.2% in 2016. For a residential customer using 1,000-kilowatt hours per month, the initial monthly increase is expected to be $1.13 in 2012, upon approval by the Commission. It is estimated that this amount will increase to a maximum of $9.46 per month in 2016. Exhibit RMC-5 shows the details of the impact on the calculation of the environmental surcharge and a residential customer for 2012 through 2020.

Environmental Cost Recovery Surcharge Summary

	2012	2013	2014	2015	2016
Total E(m) - ($000)	$22,998	$69,805	$143,788	$199,867	$232,668
12 Month Average Jurisdictional Ratio	86.99%	86.99%	86.99%	86.99%	86.99%
Jurisdictional E(m) - ($000)	$20,005	$60,722	$125,079	$173,861	$202,394
Forecasted Jurisdictional R(m) - (million)	$1,365	$1,442	$1,505	$1,560	$1,655
Incremental Billing Factor	1.47%	4.21%	8.31%	11.15%	12.23%
Residential Customer Impact **Monthly bill (1,000 kWh per month)**	$1.13	$3.26	$6.43	$8.63	$9.46

Q. What is your recommendation to the Commission?

A. Based on my testimony, the Commission should issue an order on December 1, 2011, that approves (1) the proposed assessment through its existing environmental surcharge tariff for the recovery of the costs of the 2011 Environmental Compliance Plan, (2) the 2011 Plan proposed in this proceeding for the purposes of recovering the costs of pollution control facilities in that plan through the proposed environmental surcharge tariff, beginning with the expense month of December 2011 and for bills rendered on and after January 31, 2012, and (3) the proposed reporting formats.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **Robert M. Conroy**, being duly sworn, deposes and says that he is Director - Rates for LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Robert M. Conroy

Robert M. Conroy

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 27th day of May 2011.

Kimberly M Walters (SEAL)
Notary Public

My Commission Expires:

9/11/2012

APPENDIX A

Robert M. Conroy

Director, Rates
LG&E and KU Services Company
220 West Main Street
Louisville, Kentucky 40202
(502) 627-3324

Education

Masters of Business Administration
Indiana University (Southeast campus), December 1998. GPA: 3.9.

Bachelor of Science in Electrical Engineering;
Rose Hulman Institute of Technology, May 1987. GPA: 3.3

Essentials of Leadership, London Business School, 2004.

Center for Creative Leadership, Foundations in Leadership program, 1998.

Registered Professional Engineer in Kentucky, 1995.

Previous Positions

Manager, Rates	April 2004 – Feb. 2008
Manager, Generation Systems Planning	Feb. 2001 – April 2004
Group Leader, Generation Systems Planning	Feb. 2000 – Feb. 2001
Lead Planning Engineer	Oct. 1999 – Feb. 2000
Consulting System Planning Analyst	April 1996 – Oct. 1999
System Planning Analyst III & IV	Oct. 1992 - April 1996
System Planning Analyst II	Jan. 1991 - Oct. 1992
Electrical Engineer II	Jun. 1990 - Jan. 1991
Electrical Engineer I	Jun. 1987 - Jun. 1990

Professional/Trade Memberships

Registered Professional Engineer in Kentucky, 1995.

Kentucky Utilities Company

P.S.C. No. 15, First Revision of Original Sheet No. 87
Canceling P.S.C. No. 15, Original Sheet No. 87

Adjustment Clause **ECR**

Environmental Cost Recovery Surcharge

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This schedule is mandatory to all Standard Electric Rate Schedules listed in Section 1 of the General Index except CTAC and Special Charges, all Pilot Programs listed in Section 3 of the General Index, and the FAC and DSM Adjustment Clauses. T T T

RATE

The monthly billing amount under each of the schedules to which this mechanism is applicable, including the fuel clause and demand-side management cost recovery mechanisms, shall be increased or decreased by a percentage factor calculated in accordance with the following formula. T

Jurisdictional Environmental Surcharge Billing Factor = E(m) / R(m) T

As set forth below, E(m) is the jurisdictional total of each approved environmental compliance plan revenue requirement of environmental compliance costs for the current expense month and R(m) is the revenue for the current expense month. T T

DEFINITIONS

1) For all Plans, E(m) = [(RB/12) (ROR + (ROR – DR) (TR / (1 – TR))] + OE – BAS + BR
   a) RB is the Total Environmental Compliance Rate Base.
   b) ROR is the Rate of Return on Environmental Compliance Rate Base, designated as the overall rate of return [cost of short-term debt, long-term debt, preferred stock, and common equity].
   c) DR is the Debt Rate [cost of short-term debt, and long-term debt].
   d) TR is the Composite Federal and State Income Tax Rate.
   e) OE is the Operating Expenses [Depreciation and Amortization Expense, Property Taxes, Emission Allowance Expense and O&M expense adjusted for the Average Month Expense already included in existing rates]. Includes operation and maintenance expense recovery authorized by the K.P.S.C. in all approved ECR Plan proceedings. T
   f) BAS is the total proceeds from by-product and allowance sales.
   g) BR is the operation and maintenance expenses, and/or revenues if applicable, associated with Beneficial Reuse.
   h) Plans are the environmental surcharge compliance plans submitted to and approved by the Kentucky Public Service Commission pursuant to KRS 278.183. T T
2) Total E(m) (sum of each approved environmental compliance plan revenue requirement) is multiplied by the Jurisdictional Allocation Factor and reduced by current expense month ECR revenue collected through base rates to arrive at the Net Jurisdictional E(m).
3) The revenue R(m) is the average monthly base revenue for the Company for the 12 months ending with the current expense month. Base revenue includes the customer, energy and demand charge for each rate schedule to which this mechanism is applicable and automatic adjustment clause revenues for the Fuel Adjustment Clause and the Demand-Side Management Cost Recovery Mechanism as applicable for each rate schedule.
4) Current expense month (m) shall be the second month preceding the month in which the Environmental Surcharge is billed.

Date of Issue: June 1, 2011
Date Effective: December 1, 2011
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 15, First Revision of Original Sheet No. 87
Canceling P.S.C. No. 15, Original Sheet No. 87

Adjustment Clause **ECR**

Environmental Cost Recovery Surcharge

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This schedule is mandatory to all Standard Electric Rate Schedules listed in Section 1 of the General Index except CTAC and Special Charges, all Pilot Programs listed in Section 3 of the General Index, and the FAC and DSM Adjustment Clauses.

Deleted: To electric rate schedules RS, VFD, GS, AES, PS, TODS, TODP, RTS, FLS, ST.LT., P.O.LT., LE, TE, LEV, FAC, and DSM.

RATE

The monthly billing amount under each of the schedules to which this mechanism is applicable, including the fuel clause and demand-side management cost recovery mechanisms, shall be increased or decreased by a percentage factor calculated in accordance with the following formula.

Jurisdictional Environmental Surcharge Billing Factor = E(m) / R(m)

Deleted: CESF

As set forth below, E(m) is the jurisdictional total of each approved environmental compliance plan revenue requirement of environmental compliance costs for the current expense month and R(m) is the revenue for the current expense month.

Deleted: as set forth below.

DEFINITIONS

1) For all Plans, E(m) = [(RB/12) (ROR + (ROR – DR) (TR / (1 – TR))] + OE – BAS + BR
   a) RB is the Total Environmental Compliance Rate Base.
   b) ROR is the Rate of Return on Environmental Compliance Rate Base, designated as the overall rate of return [cost of short-term debt, long-term debt, preferred stock, and common equity].
   c) DR is the Debt Rate [cost of short-term debt, and long-term debt].
   d) TR is the Composite Federal and State Income Tax Rate.
   e) OE is the Operating Expenses [Depreciation and Amortization Expense, Property Taxes, Emission Allowance Expense and O&M expense adjusted for the Average Month Expense already included in existing rates]. Includes operation and maintenance expense recovery authorized by the K.P.S.C. in all approved ECR Plan proceedings.
   f) BAS is the total proceeds from by-product and allowance sales.
   g) BR is the operation and maintenance expenses, and/or revenues if applicable, associated with Beneficial Reuse.
   h) Plans are the environmental surcharge compliance plans submitted to and approved by the Kentucky Public Service Commission pursuant to KRS 278.183.

Deleted: prior

Deleted: amended

2) Total E(m) (sum of each approved environmental compliance plan revenue requirement) is multiplied by the Jurisdictional Allocation Factor and reduced by current expense month ECR revenue collected through base rates to arrive at the Net Jurisdictional E(m).
3) The revenue R(m) is the average monthly base revenue for the Company for the 12 months ending with the current expense month. Base revenue includes the customer, energy and demand charge for each rate schedule to which this mechanism is applicable and automatic adjustment clause revenues for the Fuel Adjustment Clause and the Demand-Side Management Cost Recovery Mechanism as applicable for each rate schedule.
4) Current expense month (m) shall be the second month preceding the month in which the Environmental Surcharge is billed.

Date of Issue: June 1, 2011
Date Effective: December 1, 2011
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Lexington, Kentucky

Deleted: August 6, 2010

Deleted: August 1, 2010

Deleted: Issued by Authority of an Order of the KPSC in Case No. 2009-00548 dated July 30, 2010

ES FORM 1.00

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT

Net Jurisdictional E(m) and
Jurisdictional Environmental Surcharge Billing Factor
For the Expense Month of

Net Jurisdictional E(m) = Jurisdictional E(m) less Expense Month Revenue Collected Through Base Rates -- ES Form 1.10, line 14 =

Jurisdictional Environmental Surcharge Billing Factor -- ES Form 1.10, line 16 =

Effective Date for Billing:

Submitted by: ____________________

Title: Director, Rates

Date Submitted:

ES FORM 1.10

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Calculation of Total E(m) and
Jurisdictional Surcharge Billing Factor

For the Expense Month of

Calculation of Total E(m)

E(m) = [(RB / 12) (ROR+(ROR -DR)(TR/(1-TR)))] + OE - BAS + BR, where

RB	=	Environmental Compliance Rate Base
ROR	=	Rate of Return on the Environmental Compliance Rate Base
DR	=	Debt Rate (both short-term and long-term debt)
TR	=	Composite Federal & State Income Tax Rate
OE	=	Pollution Control Operating Expenses
BAS	=	Total Proceeds from By-Product and Allowance Sales
BR	=	Beneficial Reuse Operating Expenses

			Environmental Compliance Plans
(1) RB		=	
(2) RB / 12		=	
(3) (ROR + (ROR - DR) (TR / (1 - TR)))		=	
(4) OE		=	
(5) BAS		=	
(6) BR		=	
(7) E(m)	(2) x (3) + (4) - (5) + (6)	=	

Calculation of Jurisdictional Environmental Surcharge Billing Factor

(8)	Jurisdictional Allocation Ratio for Expense Month -- ES Form 3.00	=	
(9)	Jurisdictional E(m) = E(m) x Jurisdictional Allocation Ratio [(7) x (8)]	=	
(10)	Adjustment for (Over)/Under-collection pursuant to Case No.	=	
(11)	Prior Period Adjustment (if necessary)	=	
(12)	Adjusted Jurisdictional E(m) [(9) + (10) + (11)]	=	
(13)	Revenue Collected through Base Rates	=	
(14)	Net Jurisdictional E(m) = Jurisdictional E(m) less Expense Month Revenue Collected Through Base Rates [(12) - (13)]	=	
(15)	Jurisdictional R(m) = Average Monthly Jurisdictional Revenue for the 12 Months Ending with the Current Expense Month -- ES Form 3.00	=	
(16)	Jurisdictional Environmental Surcharge Billing Factor [(14) ÷ (15)]	=	

ES FORM 2.00

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Revenue Requirements of Environmental Compliance Costs
For the Expense Month of

Determination of Environmental Compliance Rate Base

	Enviromental Compliance Plan	
Eligible Pollution Control Plant		
Eligible Pollution CWIP Excluding AFUDC		
Subtotal		
Additions:		
Inventory - Limestone		
Less: Limestone Inventory in base rates		
Inventory - Emission Allowances per ES Form 2.31, 2.32 and 2.33		
Less: Allowance Inventory Baseline		
Net Emission Allowance Inventory		
Cash Working Capital Allowance		
Subtotal		
Deductions:		
Accumulated Depreciation on Eligible Pollution Control Plant		
Pollution Control Deferred Income Taxes		
Pollution Control Deferred Investment Tax Credit		
Subtotal		
Environmental Compliance Rate Base		

Determination of Pollution Control Operating Expenses

	Enviromental Compliance Plan
Monthly Operations & Maintenance Expense	
Monthly Depreciation & Amortization Expense	
Monthly Taxes Other Than Income Taxes	
Monthly Insurance Expense	
Monthly Emission Allowance Expense from ES Form 2.31, 2.32 and 2.33 (See Note 1)	
Less Monthly Emission Allowance Expense in base rates (1/12 of $58,345.76)	
Net Recoverable Emission Allowance Expense	
Monthly Surcharge Consultant Fee	
Total Pollution Control Operations Expense	

Determination of Beneficial Reuse Operating Expenses

	Environmental Compliance Plan
Total Monthly Beneficial Reuse Expense	
Adjustment for Beneficial Reuse in Base Rates (from ES Form 2.61)	
Net Beneficial Reuse Operations Expense	

Proceeds From By-Product and Allowance Sales

	Total Proceeds	Amount in Base Rates	Net Proceeds
	(1)	(2)	(1) - (2)
Allowance Sales			
Scrubber By-Products Sales			
Total Proceeds from Sales			

Note 1: Monthly Emission Allowance Expense includes KU's share of Trimble County Unit 2 SO_2 emission allowance expense not reflected on ES Form 2.31. Current month KU TC2 emission allowance expense =

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT

Limestone Inventory

For the Month Ended:

	Beginning Inventory	Purchases	Other Adjustments	Utilized	Ending Inventory	Reason(s) for Adjustments
Spare Parts						
Limestone						
At Ghent:						
Tons						
Dollars						
$/Ton						
At E.W. Brown:						
Tons						
Dollars						
$/Ton						

Ghent Limestone Inventory in Base Rates: $ 76,473.34

Net to be included in ECR

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Plant, CWIP & Depreciation Expense

For the Month Ended:

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Description	Eligible Plant In Service	Eligible Accumulated Depreciation	CWIP Amount Excluding AFUDC	Eligible Net Plant In Service	Unamortized ITC as of	Deferred Tax Balance as of	Monthly Depreciation Expense	Monthly Property Tax Expense
				(2)-(3)+(4)				
2001 Plan: Project 16 - KU Nox modifications Project 17 - KU Nox SCR's								
Subtotal Less Retirements and Replacement resulting from implementation of 2001 Plan								
Net Total - 2001 Plan:								
2003 Plan: Project 18 - Ghent Ash Pond Dike Elevation								
Subtotal Less Retirements and Replacement resulting from implementation of 2003 Plan								
Net Total - 2003 Plan:								
2005 Plan: Project 19 - Ash Handling at Ghent 1 and Ghent Station Project 20 - ATB Expansion at E.W. Brown Station (Phase I) Project 21 - FGD's at all E.W. Brown Units and at Ghent 1, 3, and 4								
Subtotal Less Retirements and Replacement resulting from implementation of 2005 Plan								
Net Total - 2005 Plan:								

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Plant, CWIP & Depreciation Expense

For the Month Ended:

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Description	Eligible Plant In Service	Eligible Accumulated Depreciation	CWIP Amount Excluding AFUDC	Eligible Net Plant In Service	Unamortized ITC as of	Deferred Tax Balance as of	Monthly Depreciation Expense	Monthly Property Tax Expense
				(2)-(3)+(4)				
2006 Plan:								
Project 23 - TC2 AQCS Equipment								
Project 24 - Sorbent Injection								
Project 25 - Mercury Monitors								
Project 27 - E.W. Brown Electrostatic Precipitators								
Subtotal								
Less Retirements and Replacement resulting from implementation of 2006 Plan								
Net Total - 2006 Plan:								
2009 Plan:								
Project 28 - Brown 3 SCR								
Project 29 - ATB Expansion at E.W. Brown Station (Phase II)								
Project 30 - Ghent CCP Storage (Landfill- Phase I)								
Project 31 - Trimble County Ash Treatment Basin (BAP/GSP)								
Project 32 - Trimble County CCP Storage (Landfill - Phase I)								
Project 33 - Beneficial Reuse								
Subtotal								
Less Retirements and Replacement resulting from implementation of 2009 Plan								
Net Total - 2009 Plan:								
Net Total - All Plans:								

Note 1: Trimble County projects for the 2009 Plan are proportionately shared by KU at 48% and LG&E at 52%

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Inventory of Emission Allowances

For the Month Ended:

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	
Current Year							
2012							
2013							
2014							
2015							
2016							
2017							
2018							
2019							
2020							
2021							
2022							
2023							
2024							
2025							
2026							
2027							
2028							
2029							
2030							
2031 - 2040							

In the "Comments and Explanation" Column, describe any allowance inventory adjustment 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

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Inventory of Emission Allowances (SO_2) - Current Vintage Year

For the Month Ended:

	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	162,079	0	2,682	0	0	159,397	
Dollars	$ 536,861.63	$ -	$ 8,883.70	$ -	$ -	$ 527,977.93	
$/Allowance	$ 3.31	$ -	$ 3.31	$ -	$ -	$ 3.31	
ALLOCATED ALLOWANCES FROM EPA: COAL FUEL							
Quantity	162,079	-	2,682	-	-	159,397	
Dollars	$ 536,861.63	$ -	$ 8,883.70	$ -	$ -	$ 527,977.93	
ALLOCATED ALLOWANCES FROM EPA: OTHER FUELS							
Quantity	-	-	-	-	-	0	
Dollars	$ -	$ -	$ -	$ -	$ -	$ -	
ALLOWANCES FROM PURCHASES:							
From Market:							
Quantity	0	0				0	
Dollars	$ -	$ -				$ -	
$/Allowance	$ -	$ -	$ -	$ -	$ -	$ -	
From LG&E							
Quantity	0	0					
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

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Inventory of Emission Allowances (NOx) - Ozone Season Allowance Allocation

For the Month Ended:

	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 LG&E:							
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.

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Inventory of Emission Allowances (NOx) - Annual Allowance Allocation

For the Month Ended:

	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 LG&E:							
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 2.40

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
O&M Expenses and Determination of Cash Working Capital Allowance

For the Month Ended:

Environmental Compliance Plan	
O&M Expenses	Amount
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	

Determination of Working Capital Allowance	
12 Months O&M Expenses	
One Eighth (1/8) of 12 Month O&M Expenses	1/8
Pollution Control Cash Working Capital Allowance	

ES FORM 2.50

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Pollution Control - Operations & Maintenance Expenses

For the Month Ended:

O&M Expense Account	E. W. Brown	Ghent	Green River	Tyrone	Trimble County	Total
2001 Plan						
506154 - ECR NOx Operation -- Consumables						
506155 - ECR NOx Operation -- Labor and Other						
512151 - ECR NOx Maintenance						
Total 2001 Plan O&M Expenses						
2005 Plan						
502056 - ECR Scrubber Operations						
512055 - ECR Scrubber Maintenance						
Total 2005 Plan O&M Expenses						
2006 Plan						
506159 - ECR Sorbent Injection Operation						
506152 - ECR Sorbent Reactant - Reagent Only						
512152 - ECR Sorbent Injection Maintenance						
506150 - ECR Mercury Monitors Operation						
512153 - ECR Mercury Monitors Maintenance						
506154 - ECR NOx Operation -- Consumables						
506155 - ECR NOx Operation -- Labor and Other						
512151 - ECR NOx Maintenance						
502056 - ECR Scrubber Operations						
512055 - ECR Scrubber Maintenance						
506051 - ECR Precipitator Operation						
506151 - ECR Activated Carbon						
512051 - ECR Precipitator Maintenance						
Total 2006 Plan O&M Expenses						
2009 Plan						
506154 - ECR NOx Operation -- Consumables						
506155 - ECR NOx Operation -- Labor and Other						
512151 - ECR NOx Maintenance						
506159 - ECR Sorbent Injection Operation						
506152 - ECR Sorbent Reactant - Reagent Only						
512152 - ECR Sorbent Injection Maintenance						
502012 - ECR Landfill Operations						
512105 - ECR Landfill Maintenance						
Adjustment for CCP Disposal in Base Rates (ES Form 2.51)						
Total 2009 Plan O&M Expenses						
Current Month O&M Expense for All Plans						

Note 1: Trimble County projects for the 2009 Plan are proportionately shared by KU at 48% and LG&E at 52%.

ES FORM 2.51

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
CCP Disposal Facilities Expenses
For the Month Ended:

	On-Site CCP Disposal O&M Expense	Ghent	Trimble County
	Existing CCP Disposal Facilities (Pre 2009 Plan Project)		
(1)	12 Months Ending with Expense Month		
(2)	Monthly Amount [(1) / 12]		
	2009 Plan Project		
(3)	Monthly Expense		
	Total Generating Station		
(4)	Monthly Expense [(2) + (3)]		
	Base Rates		
(5)	Annual Expense Amount (12 Mo Ending with Last Test Year)		
(6)	Monthly Expense Amount [(5) / 12]		
(7)	Total Generating Station Less Base Rates [(4) - (6)]		
(8)	Less 2009 Plan Project [(7) - (3)]		
	If Line (8) Greater than Zero, No Adjustment		
	If Line (8) Less than Zero, Adjustment for Base Rates		
	Adjustment for Base Rate Amount (to ES Form 2.50)		

Note 1: Trimble County projects for the 2009 Plan are proportionately shared by KU at 48% and LG&E at 52%.

Note 2: ES Form 2.51 will not be utilized until O&M costs associated with the 2009 Plan are incurred.

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Beneficial Reuse - Operations & Maintenance Expenses
For the Month Ended:

Third Party	O&M Expense Account	Plant	Total O&M
Total Monthly Beneficial Reuse Expense			
Adjustment for Beneficial Reuse in Base Rates (from ES Form 2.61)			
Net Beneficial Reuse O&M Expense			

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Beneficial Reuse Opportunities
For the Month Ended:

	On-Site CCP Disposal O&M Expense	E. W. Brown	Ghent	Green River	Tyrone	Trimble County	Total
	Existing Beneficial Reuse Opportunities (Pre 2009 Plan Project)						
(1)	12 Months Ending with Expense Month						
(2)	Monthly Amount [(1) / 12]						
	2009 Plan Project 33						
(3)	Monthly Amount (Expense/Revenue)						
	Total Beneficial Reuse - Generating Station						
(4)	Monthly Expense [(2) + (3)]						
	Beneficial Reuse in Base Rates						
(5)	Annual Expense Amount (12 Mo Ending with Last Test Year)						
(6)	Monthly Expense Amount [(5) / 12]						
(7)	Total Generating Station Less Base Rates [(4) - (6)]						
(8)	Less 2009 Plan Project 33 [(7) - (3)]						
	If Line (8) Greater than Zero, No Adjustment						
	If Line (8) Less than Zero, Adjustment for Base Rates						
	Adjustment for Base Rate Amount (to ES Form 2.60)						

Note 1: Trimble County projects for the 2009 Plan are proportionately shared by KU at 48% and LG&E at 52%.

ES FORM 3.00

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Monthly Average Revenue Computation of R (m)

For the Month Ended:

	Kentucky Jurisdictional Revenues						Non-Jurisdictional Revenues	Total Company Revenues	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Month	Base Rate Revenues	Fuel Clause Revenues	DSM Revenues	Environmental Surcharge Revenues	Total (2)+(3)+(4)+(5)	Total Excluding Environmental Surcharge (6)-(5)	Total Including Off-System Sales (See Note 1)	Total (6)+(8)	Total Excluding Environmental Surcharge (9)-(5)
Average Monthly Jurisdictional Revenues, Excluding Environmental Surcharge, for 12 Months Ending Current Expense Month.									
Jurisdictional Allocation Percentage for Current Month (Environmental Surcharge Excluded from Calculations): Expense Month Kentucky Jurisdictional Revenues Divided by Expense Month Total Company Revenues: Column (7) / Column (10) =									
							Note 1 - Excludes Brokered Sales, Total for Current Month =		

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Reconciliation of Reported Revenues

For the Month Ended:

	Revenues per Form 3.00	Revenues per Income Statement
Kentucky Retail Revenues		
Base Rates (Customer Charge, Energy Charge, Demand Charge)		
Fuel Adjustment Clause		
DSM		
Environmental Surcharge		
CSR Credits		
Total Kentucky Jurisdictional Revenues for Environmental Surcharge Purposes =		
Non -Jurisdictional Revenues		
Tennessee Retail		
Virginia Retail		
Wholesale		
InterSystem (Total Less Transmission Portion Booked in Account 447)		
Total Non-Jurisdictional Revenues for Environmental Surcharge Purposes =		
Total Company Revenues for Environmental Surcharge Purposes =		
Reconciling Revenues		
Brokered		
InterSystem (Transmission Portion Booked in Account 447)		
Unbilled		
Provision for Refund		
Miscellaneous		
Total Company Revenues per Income Statement =		

ES FORM 1.00

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT

Net Jurisdictional E(m) and
Jurisdictional Environmental Surcharge Billing Factor
For the Expense Month of

Net Jurisdictional E(m) = Jurisdictional E(m) less Expense Month Revenue
Collected Through Base Rates -- ES Form 1.10, line 14 =

Jurisdictional Environmental Surcharge Billing Factor -- ES Form 1.10, line 16 =

Effective Date for Billing:

Submitted by: ______________________________

Title: Director, Rates

Date Submitted:

ES FORM 1.10

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Calculation of Total E(m) and
Jurisdictional Surcharge Billing Factor

For the Expense Month of

Calculation of Total E(m)

E(m) = [(RB / 12) (ROR+(ROR -DR)(TR/(1-TR)))] + OE - BAS + BR, where

RB	=	Environmental Compliance Rate Base
ROR	=	Rate of Return on the Environmental Compliance Rate Base
DR	=	Debt Rate (both short-term and long-term debt)
TR	=	Composite Federal & State Income Tax Rate
OE	=	Pollution Control Operating Expenses
BAS	=	Total Proceeds from By-Product and Allowance Sales
BR	=	Beneficial Reuse Operating Expenses

				Environmental Compliance Plans
(1)	RB		=	
(2)	RB / 12		=	
(3)	(ROR + (ROR - DR) (TR / (1 - TR)))		=	
(4)	OE		=	
(5)	BAS		=	
(6)	BR		=	
(7)	E(m)	(2) x (3) + (4) - (5) + (6)	=	

Calculation of Jurisdictional Environmental Surcharge Billing Factor

(8)	Jurisdictional Allocation Ratio for Expense Month -- ES Form 3.00	=	
(9)	Jurisdictional E(m) = E(m) x Jurisdictional Allocation Ratio [(7) x (8)]	=	
(10)	Adjustment for (Over)/Under-collection pursuant to Case No.	=	
(11)	Prior Period Adjustment (if necessary)	=	
(12)	Adjusted Jurisdictional E(m) [(9) + (10) + (11)]	=	
(13)	Revenue Collected through Base Rates	=	
(14)	Net Jurisdictional E(m) = Jurisdictional E(m) less Expense Month Revenue Collected Through Base Rates [(12) - (13)]	=	
(15)	Jurisdictional R(m) = Average Monthly Jurisdictional Revenue for the 12 Months Ending with the Current Expense Month -- ES Form 3.00	=	
(16)	Jurisdictional Environmental Surcharge Billing Factor [(14) ÷ (15)]	=	

ES FORM 2.00

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT

Revenue Requirements of Environmental Compliance Costs
For the Expense Month of

Determination of Environmental Compliance Rate Base

	Enviromental Compliance Plan	
Eligible Pollution Control Plant		
Eligible Pollution CWIP Excluding AFUDC		
Subtotal		
Additions:		
Inventory - Limestone		
Less: Limestone Inventory in base rates		
Inventory - Emission Allowances per ES Form 2.31, 2.32 and 2.33		
Less: Allowance Inventory Baseline		
Net Emission Allowance Inventory		
Cash Working Capital Allowance		
Subtotal		
Deductions:		
Accumulated Depreciation on Eligible Pollution Control Plant		
Pollution Control Deferred Income Taxes		
Pollution Control Deferred Investment Tax Credit		
Subtotal		
Environmental Compliance Rate Base		

Determination of Pollution Control Operating Expenses

	Enviromental Compliance Plan
Monthly Operations & Maintenance Expense	
Monthly Depreciation & Amortization Expense	
Monthly Taxes Other Than Income Taxes	
Monthly Emission Allowance Expense from ES Form 2.31, 2.32 and 2.33	
Add KU Current Month TC2 SO_2 Emission Allowance Expense not reflected on ES Form 2.31	
Less Monthly Emission Allowance Expense in base rates (1/12 of $58,345.76)	
Net Recoverable Emission Allowance Expense	
Total Pollution Control Operations Expense	

Determination of Beneficial Reuse Operating Expenses

	Environmental Compliance Plan
Total Monthly Beneficial Reuse Expense	
Adjustment for Beneficial Reuse in Base Rates (from ES Form 2.61)	
Net Beneficial Reuse Operations Expense	

Proceeds From By-Product and Allowance Sales

	Total Proceeds	Amount in Base Rates	Net Proceeds
	(1)	(2)	(1) - (2)
Allowance Sales			
Scrubber By-Products Sales			
Total Proceeds from Sales			

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT

Limestone Inventory

For the Month Ended:

	Beginning Inventory	Purchases	Other Adjustments	Utilized	Ending Inventory	Reason(s) for Adjustments
Spare Parts						
Limestone						
At Ghent:						
Tons						
Dollars						
$/Ton						
At E.W. Brown:						
Tons						
Dollars						
$/Ton						

Ghent Limestone Inventory in Base Rates: $ 76,473.34

Net to be included in ECR

ES FORM 2.10

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Plant, CWIP & Depreciation Expense

For the Month Ended:

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Description	Eligible Plant In Service	Eligible Accumulated Depreciation	CWIP Amount Excluding AFUDC	Eligible Net Plant In Service	Unamortized ITC as of	Deferred Tax Balance as of	Monthly Depreciation Expense	Monthly Property Tax Expense
				(2)-(3)+(4)				
2005 Plan:								
Project 19 - Ash Handling at Ghent 1 and Ghent Station								
Project 20 - ATB Expansion at E.W. Brown Station (Phase I)								
Project 21 - FGD's at all E.W. Brown Units and at Ghent 1, 3, and 4								
Subtotal								
Less Retirements and Replacement resulting from implementation of 2005 Plan								
Net Total - 2005 Plan:								
2006 Plan:								
Project 23 - TC2 AQCS Equipment								
Project 24 - Sorbent Injection								
Project 25 - Mercury Monitors								
Project 27 - E.W. Brown Electrostatic Precipitators								
Subtotal								
Less Retirements and Replacement resulting from implementation of 2006 Plan								
Net Total - 2006 Plan:								
2009 Plan:								
Project 28 - Brown 3 SCR								
Project 29 - Brown Landfill (Phase I) & Aux Pond (Phase II)								
Project 30 - Ghent CCP Storage (Landfill- Phase I)								
Project 31 - Trimble County Ash Treatment Basin (BAP/GSP)								
Project 32 - Trimble County CCP Storage (Landfill - Phase I)								
Project 33 - Beneficial Reuse								
Subtotal								
Less Retirements and Replacement resulting from implementation of 2009 Plan								
Net Total - 2009 Plan:								
2011 Plan:								
Project 34 - E.W. Brown Station Air Compliance								
Project 35 - Ghent Station Air Compliance								
Subtotal								
Less Retirements and Replacement resulting from implementation of 2011 Plan								
Net Total - 2011 Plan:								
Net Total - All Plans:								

Note 1: Trimble County projects for the 2009 Plan are proportionately shared by KU at 48% and LG&E at 52%

ES FORM 2.30

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Inventory of Emission Allowances

For the Month Ended:

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	
Current Year							
2012							
2013							
2014							
2015							
2016							
2017							
2018							
2019							
2020							
2021							
2022							
2023							
2024							
2025							
2026							
2027							
2028							
2029							
2030							
2031 - 2040							

In the "Comments and Explanation" Column, describe any allowance inventory adjustment 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.

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Inventory of Emission Allowances (SO_2) - Current Vintage Year

For the Month Ended:

	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 LG&E							
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

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Inventory of Emission Allowances (NOx) - Ozone Season Allowance Allocation

For the Month Ended:

	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 LG&E:							
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.

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Inventory of Emission Allowances (NOx) - Annual Allowance Allocation

For the Month Ended:

	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 LG&E:							
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 2.40

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
O&M Expenses and Determination of Cash Working Capital Allowance

For the Month Ended:

Environmental Compliance Plan	
O&M Expenses	Amount
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	

Determination of Working Capital Allowance	
12 Months O&M Expenses	
One Eighth (1/8) of 12 Month O&M Expenses	1/8
Pollution Control Cash Working Capital Allowance	

ES FORM 2.50

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Pollution Control - Operations & Maintenance Expenses

For the Month Ended:

O&M Expense Account	E. W. Brown	Ghent	Green River	Tyrone	Trimble County	Total
2005 Plan						
502056 - ECR Scrubber Operations						
512055 - ECR Scrubber Maintenance						
Total 2005 Plan O&M Expenses						
2006 Plan						
506159 - ECR Sorbent Injection Operation						
506152 - ECR Sorbent Reactant - Reagent Only						
512152 - ECR Sorbent Injection Maintenance						
506150 - ECR Mercury Monitors Operation						
512153 - ECR Mercury Monitors Maintenance						
506154 - ECR NOx Operation -- Consumables						
506155 - ECR NOx Operation -- Labor and Other						
512151 - ECR NOx Maintenance						
502056 - ECR Scrubber Operations						
512055 - ECR Scrubber Maintenance						
506051 - ECR Precipitator Operation						
506151 - ECR Activated Carbon						
512051 - ECR Precipitator Maintenance						
Total 2006 Plan O&M Expenses						
2009 Plan						
506154 - ECR NOx Operation -- Consumables						
506155 - ECR NOx Operation -- Labor and Other						
512151 - ECR NOx Maintenance						
502012 - ECR Landfill Operations						
512105 - ECR Landfill Maintenance						
Adjustment for CCP Disposal in Base Rates (ES Form 2.51)						
Total 2009 Plan O&M Expenses						
2011 Plan						
506159 - ECR Sorbent Injection Operation						
506152 - ECR Sorbent Reactant - Reagent Only						
512152 - ECR Sorbent Injection Maintenance						
506156 - ECR Baghouse Operations						
512156 - ECR Baghouse Maintenance						
506151 - ECR Activated Carbon						
Total 2011 Plan O&M Expenses						
Current Month O&M Expense for All Plans						

Note 1: Trimble County projects for the 2009 Plan are proportionately shared by KU at 48% and LG&E at 52%.

ES FORM 2.51

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
CCP Disposal Facilities Expenses
For the Month Ended:

	On-Site CCP Disposal O&M Expense	Ghent	Trimble County
	Existing CCP Disposal Facilities (Pre 2009 Plan Project)		
(1)	12 Months Ending with Expense Month		
(2)	Monthly Amount [(1) / 12]		
	2009 Plan Project		
(3)	Monthly Expense		
	Total Generating Station		
(4)	Monthly Expense [(2) + (3)]		
	Base Rates		
(5)	Annual Expense Amount (12 Mo Ending with Last Test Year)		
(6)	Monthly Expense Amount [(5) / 12]		
(7)	Total Generating Station Less Base Rates [(4) - (6)]		
(8)	Less 2009 Plan Project [(7) - (3)]		
	If Line (8) Greater than Zero, No Adjustment		
	If Line (8) Less than Zero, Adjustment for Base Rates		
	Adjustment for Base Rate Amount (to ES Form 2.50)		

Note 1: Trimble County projects for the 2009 Plan are proportionately shared by KU at 48% and LG&E at 52%.

Note 2: ES Form 2.51 will not be utilized until O&M costs associated with the 2009 Plan are incurred.

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Beneficial Reuse - Operations & Maintenance Expenses
For the Month Ended:

Third Party	O&M Expense Account	Plant	Total O&M
Total Monthly Beneficial Reuse Expense			
Adjustment for Beneficial Reuse in Base Rates (from ES Form 2.61)			
Net Beneficial Reuse O&M Expense			

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Beneficial Reuse Opportunities
For the Month Ended:

On-Site CCP Disposal O&M Expense	E. W. Brown	Ghent	Green River	Tyrone	Trimble County	Total
Existing Beneficial Reuse Opportunities (Pre 2009 Plan Project)						
(1) 12 Months Ending with Expense Month						
(2) Monthly Amount [(1) / 12]						
2009 Plan Project 33						
(3) Monthly Amount (Expense/Revenue)						
Total Beneficial Reuse - Generating Station						
(4) Monthly Expense [(2) + (3)]						
Beneficial Reuse in Base Rates						
(5) Annual Expense Amount (12 Mo Ending with Last Test Year)						
(6) Monthly Expense Amount [(5) / 12]						
(7) Total Generating Station Less Base Rates [(4) - (6)]						
(8) Less 2009 Plan Project 33 [(7) - (3)]						
If Line (8) Greater than Zero, No Adjustment						
If Line (8) Less than Zero, Adjustment for Base Rates						
Adjustment for Base Rate Amount (to ES Form 2.60)						

Note 1: Trimble County projects for the 2009 Plan are proportionately shared by KU at 48% and LG&E at 52%.

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Monthly Average Revenue Computation of R (m)

For the Month Ended:

	Kentucky Jurisdictional Revenues						Non-Jurisdictional Revenues	Total Company Revenues	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Month	Base Rate Revenues	Fuel Clause Revenues	DSM Revenues	Environmental Surcharge Revenues	Total (2)+(3)+(4)+(5)	Total Excluding Environmental Surcharge (6)-(5)	Total Including Off-System Sales (See Note 1)	Total (6)+(8)	Total Excluding Environmental Surcharge (9)-(5)
Average Monthly Jurisdictional Revenues, Excluding Environmental Surcharge, for 12 Months Ending Current Expense Month.									
Jurisdictional Allocation Percentage for Current Month (Environmental Surcharge Excluded from Calculations): Expense Month Kentucky Jurisdictional Revenues Divided by Expense Month Total Company Revenues: Column (7) / Column (10) =									
							Note 1 - Excludes Brokered Sales,	Total for Current Month =	

ES FORM 3.10

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Reconciliation of Reported Revenues

For the Month Ended:

	Revenues per Form 3.00	Revenues per Income Statement
Kentucky Retail Revenues		
Base Rates (Customer Charge, Energy Charge, Demand Charge)		
Fuel Adjustment Clause		
DSM		
Environmental Surcharge		
CSR Credits		
Total Kentucky Jurisdictional Revenues for Environmental Surcharge Purposes =		
Non -Jurisdictional Revenues		
Tennessee Retail		
Virginia Retail		
Wholesale		
InterSystem (Total Less Transmission Portion Booked in Account 447)		
Total Non-Jurisdictional Revenues for Environmental Surcharge Purposes =		
Total Company Revenues for Environmental Surcharge Purposes =		
Reconciling Revenues		
Brokered		
InterSystem (Transmission Portion Booked in Account 447)		
Unbilled		
Provision for Refund		
Miscellaneous		
Total Company Revenues per Income Statement =		

Kentucky Utilities Company
Environmental Cost Recovery Surcharge Summary

	2012	2013	2014	2015	2016
Total E(m) - ($000)	$22,998	$69,805	$143,788	$199,867	$232,668
12 Month Average Jurisdictional Ratio	86.99%	86.99%	86.99%	86.99%	86.99%
Jurisdictional E(m) - ($000)	$20,005	$60,722	$125,079	$173,861	$202,394
Forecasted Jurisdictional R(m) - (million)	$1,365	$1,442	$1,505	$1,560	$1,655
Incremental Billing Factor	1.47%	4.21%	8.31%	11.15%	12.23%
Residential Customer Impact **Monthly bill (1,000 kWh per month)**	$1.13	$3.26	$6.43	$8.63	$9.46

Revenue Requirements Summary
2011 Amended Plan - KU

		2012	2013	2014	2015	2016	2017	2018	2019	2020
Project 29	**Brown Landfill (Phase I)**									
	Revenue Requirement									
	Eligible Plant	34,610,113	58,674,420	58,674,420	58,674,420	58,674,420	58,674,420	58,674,420	58,674,420	58,674,420
	Less: Retired Plant	-	-	-	-	-	-	-	-	-
	Less: Accumulated Depreciation	-	-	(1,574,430)	(3,217,314)	(4,860,198)	(6,503,082)	(8,145,965)	(9,788,849)	(11,431,733)
	Plus: Accumulated Depreciation on retired plant	-	-	-	-	-	-	-	-	-
	Less: Deferred Tax Balance	-	-	(223,495)	(1,149,392)	(1,961,725)	(2,669,296)	(3,279,646)	(3,800,319)	(4,237,810)
	Plus: Deferred Tax Balance on retired plant	-	-	-	-	-	-	-	-	-
	Environmental Compliance Rate Base	34,610,113	58,674,420	56,876,495	54,307,714	51,852,497	49,502,043	47,248,809	45,085,252	43,004,877
	Rate of return	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%
		$ 3,819,556	$ 6,475,281	$ 6,276,863	$ 5,993,373	$ 5,722,417	$ 5,463,022	$ 5,214,356	$ 4,975,587	$ 4,745,998
	Operating expenses	-	-	2,813,772	2,898,185	2,985,131	3,074,685	3,166,925	3,261,933	3,359,791
	Annual Depreciation expense	-	-	1,574,430	1,642,884	1,642,884	1,642,884	1,642,884	1,642,884	1,642,884
	Less depreciation on retired plant	-	-	-	-	-	-	-	-	-
	Annual Property Tax expense	11,832	51,915	88,012	85,650	83,186	80,721	78,257	75,793	73,328
	Total OE	$ 11,832	$ 51,915	$ 4,476,214	$ 4,626,719	$ 4,711,200	$ 4,798,290	$ 4,888,066	$ 4,980,609	$ 5,076,003
	Total E(m)	3,831,387	6,527,196	10,753,077	10,620,092	10,433,617	10,261,312	10,102,422	9,956,196	9,822,001

Revenue Requirements Summary
2011 Amended Plan - KU

		2012	2013	2014	2015	2016	2017	2018	2019	2020
Project 34	**BR Air Compliance - All Units - PM Control Systems**									
	Revenue Requirement									
	Eligible Plant	71,624,419	196,530,009	307,550,104	343,785,964	343,785,964	343,785,964	343,785,964	343,785,964	343,785,964
	Less: Retired Plant	-	-	-	-	-	-	-	-	-
	Less: Accumulated Depreciation	-	-	(4,247,407)	(13,089,386)	(23,159,043)	(33,228,699)	(43,298,356)	(53,368,012)	(63,437,668)
	Plus: Accumulated Depreciation on retired plant	-	-	-	-	-	-	-	-	-
	Less: Deferred Tax Balance	-	-	(1,521,248)	(5,777,851)	(10,605,360)	(14,801,503)	(18,412,981)	(21,483,990)	(24,054,674)
	Plus: Deferred Tax Balance on retired plant	-	-	-	-	-	-	-	-	-
	Environmental Compliance Rate Base	71,624,419	196,530,009	301,781,449	324,918,727	310,021,561	295,755,762	282,074,628	268,933,962	256,293,622
	Rate of return	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%
		$ 7,904,437	$ 21,688,958	$ 33,304,457	$ 35,857,876	$ 34,213,832	$ 32,639,465	$ 31,129,621	$ 29,679,424	$ 28,284,442
	Operating expenses	-	-	7,536,179	16,368,110	19,085,903	19,467,621	19,856,973	20,254,113	20,659,195
	Annual Depreciation expense	-	-	4,247,407	8,841,979	10,069,656	10,069,656	10,069,656	10,069,656	10,069,656
	Less depreciation on retired plant	-	-	-	-	-	-	-	-	-
	Annual Property Tax expense	7,837	107,437	294,795	454,954	496,045	480,940	465,836	450,731	435,627
	Total OE	$ 7,837	$ 107,437	$ 12,078,381	$ 25,665,043	$ 29,651,604	$ 30,018,217	$ 30,392,465	$ 30,774,500	$ 31,164,478
	Total E(m)	7,912,273	21,796,395	45,382,838	61,522,919	63,865,435	62,657,682	61,522,087	60,453,924	59,448,920

Revenue Requirements Summary
2011 Amended Plan - KU

		2012	2013	2014	2015	2016	2017	2018	2019	2020
Project 35	**GH Air Compliance - All Units - PM Control Systems**									
	Revenue Requirement									
	Eligible Plant	101,828,630	299,923,984	530,338,048	698,652,348	711,534,820	711,534,820	711,534,820	711,534,820	711,534,820
	Less: Retired Plant	-	-	-	-	-	-	-	-	-
	Less: Accumulated Depreciation	-	-	(4,400,802)	(15,808,453)	(36,310,719)	(56,812,985)	(77,315,251)	(97,817,517)	(118,319,783)
	Plus: Accumulated Depreciation on retired plant	-	-	-	-	-	-	-	-	-
	Less: Deferred Tax Balance	-	-	(2,741,380)	(12,096,178)	(22,481,196)	(31,538,360)	(39,367,343)	(46,059,617)	(51,700,784)
	Plus: Deferred Tax Balance on retired plant	-	-	-	-	-	-	-	-	-
	Environmental Compliance Rate Base	101,828,630	299,923,984	523,195,866	670,747,717	652,742,905	623,183,475	594,852,226	567,657,686	541,514,253
	Rate of return	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%
		$ 11,237,759	$ 33,099,468	$ 57,739,646	$ 74,023,398	$ 72,036,395	$ 68,774,231	$ 65,647,608	$ 62,646,431	$ 59,761,255
	Operating expenses	8,692	8,229,481	25,061,610	41,503,865	64,806,127	66,102,250	67,424,295	68,772,781	70,148,237
	Annual Depreciation expense	-	-	4,400,802	11,407,651	20,502,266	20,502,266	20,502,266	20,502,266	20,502,266
	Less depreciation on retired plant	-	-	-	-	-	-	-	-	-
	Annual Property Tax expense	7,641	152,743	449,886	788,906	1,024,266	1,012,836	982,083	951,329	920,576
	Total OE	$ 16,333	$ 8,382,224	$ 29,912,298	$ 53,700,423	$ 86,332,659	$ 87,617,352	$ 88,908,644	$ 90,226,376	$ 91,571,078
	Total E(m)	11,254,092	41,481,691	87,651,944	127,723,820	158,369,055	156,391,583	154,556,251	152,872,807	151,332,333

Revenue Requirements Summary
2011 Amended Plan - KU

	2012	2013	2014	2015	2016	2017	2018	2019	2020
Total E(m) - All KU Projects	22,997,753	69,805,282	143,787,858	199,866,832	232,668,107	229,310,577	226,180,760	223,282,928	220,603,254
	19,012,967	60,245,001	123,740,224	177,214,254	210,444,215	207,489,439	204,738,062	202,195,965	199,850,703
Total Revenue Requirements									
Project 29	3,831,387	6,527,196	10,753,077	10,620,092	10,433,617	10,261,312	10,102,422	9,956,196	9,822,001
Project 34	7,912,273	21,796,395	45,382,838	61,522,919	63,865,435	62,657,682	61,522,087	60,453,924	59,448,920
Project 35	11,254,092	41,481,691	87,651,944	127,723,820	158,369,055	156,391,583	154,556,251	152,872,807	151,332,333
Total	22,997,753	69,805,282	143,787,858	199,866,832	232,668,107	229,310,577	226,180,760	223,282,928	220,603,254
	-	-	-	-	-	-	-	-	-
12 Month Average Jurisdictional Ratio	86.99%	86.99%	86.99%	86.99%	86.99%	86.99%	86.99%	86.99%	86.99%
Jurisdictional Allocation	20,005,362	60,722,452	125,078,661	173,860,826	202,394,108	199,473,449	196,750,873	194,230,098	191,899,094
Forecasted 12-Month Retail Revenue	1,364,734,889	1,442,296,068	1,505,216,494	1,559,590,578	1,654,718,522	1,721,201,709	1,811,131,354	1,963,765,781	2,028,216,792
Billing Factor	1.47%	4.21%	8.31%	11.15%	12.23%	11.59%	10.86%	9.89%	9.46%
KU Residential Bill Impact									
Customer Charge	$8.50	$8.50	$8.50	$8.50	$8.50	$8.50	$8.50	$8.50	$8.50
Energy - 1,000 Kwh @ $0.06805	$68.05	$68.05	$68.05	$68.05	$68.05	$68.05	$68.05	$68.05	$68.05
FAC billings (12/1/2010 factor - $-0.0016/kWh)	-$1.60	-$1.60	-$1.60	-$1.60	-$1.60	-$1.60	-$1.60	-$1.60	-$1.60
DSM billings (12/1/2010 factor - $0.00243/kWh)	$2.43	$2.43	$2.43	$2.43	$2.43	$2.43	$2.43	$2.43	$2.43
ECR billings (12/1/2010 factor: 2.55%)	$1.97	$1.97	$1.97	$1.97	$1.97	$1.97	$1.97	$1.97	$1.97
Additional ECR factor	$1.13	$3.26	$6.43	$8.63	$9.46	$8.97	$8.41	$7.65	$7.32

Revenue Requirements Project Detail
2011 Amended Plan - KU Project 29 - AMENDED (2009 Plan)

	2012	2013	January 2014	2015	2016	2017	2018	2019	2020
In-Service			1	2	3	4	5	6	7
Brown 3									
Capital Expenditures - Brown Landfill - Phase I	$ 26,722,378	$ 24,064,307	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Accumulated Expenditures	$ 34,610,113	$ 58,674,420	$ 58,674,420	$ 58,674,420	$ 58,674,420	$ 58,674,420	$ 58,674,420	$ 58,674,420	$ 58,674,420
Book Depreciation rate, per year	0.000%	0.000%	2.800%	2.800%	2.800%	2.800%	2.800%	2.800%	2.800%
Tax Depreciation rate, per year	0.000%	0.000%	3.750%	7.219%	6.677%	6.177%	5.713%	5.285%	4.888%
Income tax rate	35.71%	35.71%	35.71%	35.71%	35.71%	35.71%	35.71%	35.71%	35.71%
Deferred Tax Balance	-	-	223,495	1,149,392	1,961,725	2,669,296	3,279,646	3,800,319	4,237,810
Book Accumulated Depreciation Balance	-	-	1,574,430	3,217,314	4,860,198	6,503,082	8,145,965	9,788,849	11,431,733
Unrecovered Investment -- Book	34,610,113	58,674,420	58,674,420	58,674,420	58,674,420	58,674,420	58,674,420	58,674,420	58,674,420
Book Depreciation	-	-	1,574,430	1,642,884	1,642,884	1,642,884	1,642,884	1,642,884	1,642,884
Unrecovered Investment -- Tax total	34,610,113	58,674,420	58,674,420	58,674,420	58,674,420	58,674,420	58,674,420	58,674,420	58,674,420
Tax Depreciation	-	-	2,200,291	4,235,706	3,917,691	3,624,319	3,352,070	3,100,943	2,868,006
Allowed Rate of Return	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%
Book Depreciation expense total	-	-	1,574,430	1,642,884	1,642,884	1,642,884	1,642,884	1,642,884	1,642,884
Tax Depreciation expense total	-	-	2,200,291	4,235,706	3,917,691	3,624,319	3,352,070	3,100,943	2,868,006
Annual Property Tax Rate	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%
Deferred Tax Balance	-	-	223,495	925,897	812,334	707,570	610,350	520,673	437,491
Revenue Recovery on Capital Expenditure to date									
Eligible Plant, cumulative capital expenditures	34,610,113	58,674,420	58,674,420	58,674,420	58,674,420	58,674,420	58,674,420	58,674,420	58,674,420
Less: Retired Plant	-	-	-	-	-	-	-	-	-
Less: Accumulated Depreciation	-	-	(1,574,430)	(3,217,314)	(4,860,198)	(6,503,082)	(8,145,965)	(9,788,849)	(11,431,733)
Plus: Accumulated Depreciation on Retired Plant	-	-	-	-	-	-	-	-	-
Less: Deferred Tax Balance	-	-	(223,495)	(1,149,392)	(1,961,725)	(2,669,296)	(3,279,646)	(3,800,319)	(4,237,810)
Plus: Deferred Tax Balance on Retired Plant	-	-	-	-	-	-	-	-	-
Environmental Compliance Rate Base	34,610,113	58,674,420	56,876,495	54,307,714	51,852,497	49,502,043	47,248,809	45,085,252	43,004,877
Rate of return	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%
Return on Environmental Compliance Rate Base	$ 3,819,556	$ 6,475,281	$ 6,276,863	$ 5,993,373	$ 5,722,417	$ 5,463,022	$ 5,214,356	$ 4,975,587	$ 4,745,998
Operating Expenses	-	-	2,813,772	2,898,185	2,985,131	3,074,685	3,166,925	3,261,933	3,359,791
Annual Depreciation expense	-	-	1,574,430	1,642,884	1,642,884	1,642,884	1,642,884	1,642,884	1,642,884
Less depreciation on retired plant	-	-	-	-	-	-	-	-	-
Annual Property Tax expense	11,832	51,915	88,012	85,650	83,186	80,721	78,257	75,793	73,328
Total OE	$ 11,832	$ 51,915	$ 4,476,214	$ 4,626,719	$ 4,711,200	$ 4,798,290	$ 4,888,066	$ 4,980,609	$ 5,076,003
Total E(m) - Project	3,831,387	6,527,196	10,753,077	10,620,092	10,433,617	10,261,312	10,102,422	9,956,196	9,822,001

Revenue Requirements Project Detail
2011 Amended Plan - KU Project 34

	2012	2013	May 2014	2015	2016	2017	2018	2019	2020
In-Service			1	2	3	4	5	6	7
Brown 1									
CapEx - BR1 PM Control Systems	$ 30,841,093	$ 46,546,567	$ 29,295,115	$ -	$ -	$ -	$ -	$ -	$ -
Accumulated Expenditures	$ 33,377,367	$ 79,923,934	$ 109,219,049	$ 109,219,049	$ 109,219,049	$ 109,219,049	$ 109,219,049	$ 109,219,049	$ 109,219,049
Book Depreciation rate, per year	0.000%	0.000%	2.980%	2.980%	2.980%	2.980%	2.980%	2.980%	2.980%
Tax Depreciation rate, per year	0.000%	0.000%	3.750%	7.219%	6.677%	6.177%	5.713%	5.285%	4.888%
Income tax rate	35.71%	35.71%	35.71%	35.71%	35.71%	35.71%	35.71%	35.71%	35.71%
Deferred Tax Balance	-	-	736,165	2,389,465	3,831,373	5,078,271	6,144,199	7,043,198	7,787,359
Book Accumulated Depreciation Balance	-	-	2,034,205	5,288,932	8,543,660	11,798,388	15,053,115	18,307,843	21,562,571
Unrecovered Investment -- Book	33,377,367	79,923,934	109,219,049	109,219,049	109,219,049	109,219,049	109,219,049	109,219,049	109,219,049
Book Depreciation	-	-	2,034,205	3,254,728	3,254,728	3,254,728	3,254,728	3,254,728	3,254,728
Unrecovered Investment -- Tax total	33,377,367	79,923,934	109,219,049	109,219,049	109,219,049	109,219,049	109,219,049	109,219,049	109,219,049
Tax Depreciation	-	-	4,095,714	7,884,523	7,292,556	6,746,461	6,239,684	5,772,227	5,338,627
Allowed Rate of Return	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%
Book Depreciation expense total	-	-	2,034,205	3,254,728	3,254,728	3,254,728	3,254,728	3,254,728	3,254,728
Tax Depreciation expense total	-	-	4,095,714	7,884,523	7,292,556	6,746,461	6,239,684	5,772,227	5,338,627
Annual Property Tax Rate	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%
Deferred Tax Balance	-	-	736,165	1,653,300	1,441,908	1,246,898	1,065,928	898,999	744,160
Revenue Recovery on Capital Expenditure to date									
Eligible Plant, cumulative capital expenditures	33,377,367	79,923,934	109,219,049	109,219,049	109,219,049	109,219,049	109,219,049	109,219,049	109,219,049
Less: Retired Plant	-	-	-	-	-	-	-	-	-
Less: Accumulated Depreciation	-	-	(2,034,205)	(5,288,932)	(8,543,660)	(11,798,388)	(15,053,115)	(18,307,843)	(21,562,571)
Plus: Accumulated Depreciation on Retired Plant	-	-	-	-	-	-	-	-	-
Less: Deferred Tax Balance	-	-	(736,165)	(2,389,465)	(3,831,373)	(5,078,271)	(6,144,199)	(7,043,198)	(7,787,359)
Plus: Deferred Tax Balance on Retired Plant	-	-	-	-	-	-	-	-	-
Environmental Compliance Rate Base	33,377,367	79,923,934	106,448,679	101,540,651	96,844,015	92,342,390	88,021,734	83,868,007	79,869,119
Rate of return	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%
Return on Environmental Compliance Rate Base	$ 3,683,510	$ 8,820,367	$ 11,747,625	$ 11,205,978	$ 10,687,659	$ 10,190,862	$ 9,714,037	$ 9,255,633	$ 8,814,318
Operating Expenses	-	-	2,483,343	4,809,135	4,905,317	5,003,424	5,103,492	5,205,562	5,309,673
Annual Depreciation expense	-	-	2,034,205	3,254,728	3,254,728	3,254,728	3,254,728	3,254,728	3,254,728
Less depreciation on retired plant	-	-	-	-	-	-	-	-	-
Annual Property Tax expense	3,804	50,066	119,886	160,777	155,895	151,013	146,131	141,249	136,367
Total OE	$ 3,804	$ 50,066	$ 4,637,434	$ 8,224,640	$ 8,315,940	$ 8,409,164	$ 8,504,351	$ 8,601,538	$ 8,700,768
Total E(m) - Project	3,687,315	8,870,433	16,385,059	19,430,617	19,003,599	18,600,026	18,218,387	17,857,172	17,515,086

Revenue Requirements Project Detail
2011 Amended Plan - KU Project 34

	2012	2013	April 2014	2015	2016	2017	2018	2019	2020
In-Service			1	2	3	4	5	6	7
Brown 2									
CapEx - BR2 PM Control Systems	$ 33,382,705	$ 50,067,464	$ 31,507,055	$ -	$ -	$ -	$ -	$ -	$ -
Accumulated Expenditures	$ 36,070,778	$ 86,138,242	$ 117,645,297	$ 117,645,297	$ 117,645,297	$ 117,645,297	$ 117,645,297	$ 117,645,297	$ 117,645,297
Book Depreciation rate, per year	0.000%	0.000%	3.010%	3.010%	3.010%	3.010%	3.010%	3.010%	3.010%
Tax Depreciation rate, per year	0.000%	0.000%	3.750%	7.219%	6.677%	6.177%	5.713%	5.285%	4.888%
Income tax rate	35.71%	35.71%	35.71%	35.71%	35.71%	35.71%	35.71%	35.71%	35.71%
Deferred Tax Balance	-	-	785,083	2,553,332	4,093,880	5,424,373	6,559,934	7,515,687	8,304,656
Book Accumulated Depreciation Balance	-	-	2,213,202	5,754,326	9,295,449	12,836,573	16,377,696	19,918,819	23,459,943
Unrecovered Investment -- Book	36,070,778	86,138,242	117,645,297	117,645,297	117,645,297	117,645,297	117,645,297	117,645,297	117,645,297
Book Depreciation	-	-	2,213,202	3,541,123	3,541,123	3,541,123	3,541,123	3,541,123	3,541,123
Unrecovered Investment -- Tax total	36,070,778	86,138,242	117,645,297	117,645,297	117,645,297	117,645,297	117,645,297	117,645,297	117,645,297
Tax Depreciation	-	-	4,411,699	8,492,814	7,855,177	7,266,950	6,721,076	6,217,554	5,750,502
Allowed Rate of Return	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%
Book Depreciation expense total	-	-	2,213,202	3,541,123	3,541,123	3,541,123	3,541,123	3,541,123	3,541,123
Tax Depreciation expense total	-	-	4,411,699	8,492,814	7,855,177	7,266,950	6,721,076	6,217,554	5,750,502
Annual Property Tax Rate	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%
Deferred Tax Balance	-	-	785,083	1,768,249	1,540,548	1,330,493	1,135,561	955,753	788,969
Revenue Recovery on Capital Expenditure to date									
Eligible Plant, cumulative capital expenditures	36,070,778	86,138,242	117,645,297	117,645,297	117,645,297	117,645,297	117,645,297	117,645,297	117,645,297
Less: Retired Plant	-	-	-	-	-	-	-	-	-
Less: Accumulated Depreciation	-	-	(2,213,202)	(5,754,326)	(9,295,449)	(12,836,573)	(16,377,696)	(19,918,819)	(23,459,943)
Plus: Accumulated Depreciation on Retired Plant	-	-	-	-	-	-	-	-	-
Less: Deferred Tax Balance	-	-	(785,083)	(2,553,332)	(4,093,880)	(5,424,373)	(6,559,934)	(7,515,687)	(8,304,656)
Plus: Deferred Tax Balance on Retired Plant	-	-	-	-	-	-	-	-	-
Environmental Compliance Rate Base	36,070,778	86,138,242	114,647,012	109,337,640	104,255,968	99,384,352	94,707,668	90,210,791	85,880,698
Rate of return	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%
Return on Environmental Compliance Rate Base	$ 3,980,754	$ 9,506,175	$ 12,652,390	$ 12,066,450	$ 11,505,639	$ 10,968,010	$ 10,451,893	$ 9,955,620	$ 9,477,753
Operating Expenses	-	-	5,052,836	6,871,856	7,009,293	7,149,479	7,292,469	7,438,318	7,587,085
Annual Depreciation expense	-	-	2,213,202	3,541,123	3,541,123	3,541,123	3,541,123	3,541,123	3,541,123
Less depreciation on retired plant	-	-	-	-	-	-	-	-	-
Annual Property Tax expense	4,032	54,106	129,207	173,148	167,836	162,525	157,213	151,901	146,590
Total OE	$ 4,032	$ 54,106	$ 7,395,245	$ 10,586,128	$ 10,718,253	$ 10,853,128	$ 10,990,805	$ 11,131,343	$ 11,274,798
Total E(m) - Project	3,984,786	9,560,281	20,047,635	22,652,578	22,223,892	21,821,137	21,442,698	21,086,963	20,752,551

Revenue Requirements Project Detail
2011 Amended Plan - KU Project 34

	2012	2013	2014	May 2015	2016	2017	2018	2019	2020
In-Service				1	2	3	4	5	6
Brown 3									
CapEx - BR3 PM Control Systems	$ 2,176,274	$ 28,291,560	$ 50,217,924	$ 36,235,860	$ -	$ -	$ -	$ -	$ -
Accumulated Expenditures	$ 2,176,274	$ 30,467,834	$ 80,685,758	$ 116,921,618	$ 116,921,618	$ 116,921,618	$ 116,921,618	$ 116,921,618	$ 116,921,618
Book Depreciation rate, per year	0.000%	0.000%	0.000%	2.800%	2.800%	2.800%	2.800%	2.800%	2.800%
Tax Depreciation rate, per year	0.000%	0.000%	0.000%	3.750%	7.219%	6.677%	6.177%	5.713%	5.285%
Income tax rate	35.71%	35.71%	35.71%	35.71%	35.71%	35.71%	35.71%	35.71%	35.71%
Deferred Tax Balance	-	-	-	835,054	2,680,106	4,298,859	5,708,848	6,925,104	7,962,659
Book Accumulated Depreciation Balance	-	-	-	2,046,128	5,319,934	8,593,739	11,867,544	15,141,350	18,415,155
Unrecovered Investment -- Book	2,176,274	30,467,834	80,685,758	116,921,618	116,921,618	116,921,618	116,921,618	116,921,618	116,921,618
Book Depreciation	-	-	-	2,046,128	3,273,805	3,273,805	3,273,805	3,273,805	3,273,805
Unrecovered Investment -- Tax total	2,176,274	30,467,834	80,685,758	116,921,618	116,921,618	116,921,618	116,921,618	116,921,618	116,921,618
Tax Depreciation	-	-	-	4,384,561	8,440,572	7,806,856	7,222,248	6,679,732	6,179,308
Allowed Rate of Return	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%
Book Depreciation expense total	-	-	-	2,046,128	3,273,805	3,273,805	3,273,805	3,273,805	3,273,805
Tax Depreciation expense total	-	-	-	4,384,561	8,440,572	7,806,856	7,222,248	6,679,732	6,179,308
Annual Property Tax Rate	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%
Deferred Tax Balance	-	-	-	835,054	1,845,052	1,618,753	1,409,989	1,216,256	1,037,555
Revenue Recovery on Capital Expenditure to date									
Eligible Plant, cumulative capital expenditures	2,176,274	30,467,834	80,685,758	116,921,618	116,921,618	116,921,618	116,921,618	116,921,618	116,921,618
Less: Retired Plant	-	-	-	-	-	-	-	-	-
Less: Accumulated Depreciation	-	-	-	(2,046,128)	(5,319,934)	(8,593,739)	(11,867,544)	(15,141,350)	(18,415,155)
Plus. Accumulated Depreciation on Retired Plant	-	-	-	-	-	-	-	-	-
Less: Deferred Tax Balance	-	-	-	(835,054)	(2,680,106)	(4,298,859)	(5,708,848)	(6,925,104)	(7,962,659)
Plus: Deferred Tax Balance on Retired Plant	-	-	-	-	-	-	-	-	-
Environmental Compliance Rate Base	2,176,274	30,467,834	80,685,758	114,040,436	108,921,578	104,029,020	99,345,226	94,855,164	90,543,804
Rate of return	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%
Return on Environmental Compliance Rate Base	$ 240,173	$ 3,362,416	$ 8,904,442	$ 12,585,448	$ 12,020,533	$ 11,480,593	$ 10,963,692	$ 10,468,171	$ 9,992,371
Operating Expenses	-	-	-	4,687,119	7,171,292	7,314,718	7,461,012	7,610,232	7,762,437
Annual Depreciation expense	-	-	-	2,046,128	3,273,805	3,273,805	3,273,805	3,273,805	3,273,805
Less depreciation on retired plant	-	-	-	-	-	-	-	-	-
Annual Property Tax expense	-	3,264	45,702	121,029	172,313	167,403	162,492	157,581	152,670
Total OE	$ -	$ 3,264	$ 45,702	$ 6,854,276	$ 10,617,410	$ 10,755,926	$ 10,897,309	$ 11,041,619	$ 11,188,913
Total E(m) - Project	240,173	3,365,680	8,950,144	19,439,724	22,637,944	22,236,519	21,861,001	21,509,789	21,181,284

Revenue Requirements Project Detail
2011 Amended Plan - KU Project 35

	2012	2013	May 2014	2015	2016	2017	2018	2019	2020
In-Service			1	2	3	4	5	6	7
Ghent 1									
CapEx - GH1 PM Control Systems-SAM Mitigation-SCR Turn-down	$ 50,248,800	$ 66,924,592	$ 44,857,567	$ -	$ -	$ -	$ -	$ -	$ -
Accumulated Expenditures	$ 52,427,728	$ 119,352,320	$ 164,209,888	$ 164,209,888	$ 164,209,888	$ 164,209,888	$ 164,209,888	$ 164,209,888	$ 164,209,888
Book Depreciation rate, per year	0.000%	0.000%	3.840%	3.840%	3.840%	3.840%	3.840%	3.840%	3.840%
Tax Depreciation rate, per year	0.000%	0.000%	3.750%	7.219%	6.677%	6.177%	5.713%	5.285%	4.888%
Income tax rate	35.71%	35.71%	35.71%	35.71%	35.71%	35.71%	35.71%	35.71%	35.71%
Deferred Tax Balance	-	-	791,631	2,773,055	4,436,653	5,807,055	6,905,370	7,752,709	8,367,249
Book Accumulated Depreciation Balance	-	-	3,941,037	10,246,697	16,552,357	22,858,016	29,163,676	35,469,336	41,774,995
Unrecovered Investment -- Book	52,427,728	119,352,320	164,209,888	164,209,888	164,209,888	164,209,888	164,209,888	164,209,888	164,209,888
Book Depreciation	-	-	3,941,037	6,305,660	6,305,660	6,305,660	6,305,660	6,305,660	6,305,660
Unrecovered Investment -- Tax total	52,427,728	119,352,320	164,209,888	164,209,888	164,209,888	164,209,888	164,209,888	164,209,888	164,209,888
Tax Depreciation	-	-	6,157,871	11,854,312	10,964,294	10,143,245	9,381,311	8,678,493	8,026,579
Allowed Rate of Return	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%
Book Depreciation expense total	-	-	3,941,037	6,305,660	6,305,660	6,305,660	6,305,660	6,305,660	6,305,660
Tax Depreciation expense total	-	-	6,157,871	11,854,312	10,964,294	10,143,245	9,381,311	8,678,493	8,026,579
Annual Property Tax Rate	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%
Deferred Tax Balance	-	-	791,631	1,981,424	1,663,598	1,370,402	1,098,315	847,339	614,540
Revenue Recovery on Capital Expenditure to date									
Eligible Plant, cumulative capital expenditures	52,427,728	119,352,320	164,209,888	164,209,888	164,209,888	164,209,888	164,209,888	164,209,888	164,209,888
Less: Retired Plant	-	-	-	-	-	-	-	-	-
Less: Accumulated Depreciation	-	-	(3,941,037)	(10,246,697)	(16,552,357)	(22,858,016)	(29,163,676)	(35,469,336)	(41,774,995)
Plus: Accumulated Depreciation on Retired Plant	-	-	-	-	-	-	-	-	-
Less: Deferred Tax Balance	-	-	(791,631)	(2,773,055)	(4,436,653)	(5,807,055)	(6,905,370)	(7,752,709)	(8,367,249)
Plus: Deferred Tax Balance on Retired Plant	-	-	-	-	-	-	-	-	-
Environmental Compliance Rate Base	52,427,728	119,352,320	159,477,219	151,190,136	143,220,878	135,544,816	128,140,842	120,987,843	114,067,643
Rate of return	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%
Return on Environmental Compliance Rate Base	$ 5,785,899	$ 13,171,665	$ 17,599,830	$ 16,685,271	$ 15,805,788	$ 14,958,661	$ 14,141,562	$ 13,352,161	$ 12,588,451
Operating Expenses	-	2,730,914	12,899,794	17,179,567	17,523,158	17,873,621	18,231,093	18,595,715	18,967,630
Annual Depreciation expense	-	-	3,941,037	6,305,660	6,305,660	6,305,660	6,305,660	6,305,660	6,305,660
Less depreciation on retired plant	-	-	-	-	-	-	-	-	-
Annual Property Tax expense	3,268	78,642	179,028	240,403	230,945	221,486	212,028	202,569	193,111
Total OE	$ 3,268	$ 2,809,555	$ 17,019,860	$ 23,725,630	$ 24,059,762	$ 24,400,767	$ 24,748,781	$ 25,103,944	$ 25,466,400
Total E(m) - Project	5,789,167	15,981,220	34,619,690	40,410,901	39,865,550	39,359,428	38,890,343	38,456,105	38,054,851

Revenue Requirements Project Detail
2011 Amended Plan - KU Project 35

	2012	2013	November 2014	2015	2016	2017	2018	2019	2020
In-Service			1	2	3	4	5	6	7
Ghent 2									
CapEx - GH2 PM Control Systems & SAM Mitigation	$ 37,354,857	$ 48,163,861	$ 72,191,638	$ 6,693,304	$ -	$ -	$ -	$ -	$ -
Accumulated Expenditures	$ 37,503,641	$ 85,667,502	$ 157,859,140	$ 164,552,444	$ 164,552,444	$ 164,552,444	$ 164,552,444	$ 164,552,444	$ 164,552,444
Book Depreciation rate, per year	0.000%	0.000%	2.330%	2.330%	2.330%	2.330%	2.330%	2.330%	2.330%
Tax Depreciation rate, per year	0.000%	0.000%	3.750%	7.219%	6.677%	6.177%	5.713%	5.285%	4.888%
Income tax rate	35.71%	35.71%	35.71%	35.71%	35.71%	35.71%	35.71%	35.71%	35.71%
Deferred Tax Balance	-	-	1,949,749	4,822,608	7,376,978	9,637,540	11,625,447	13,361,855	14,864,978
Book Accumulated Depreciation Balance	-	-	459,765	4,293,837	8,127,909	11,961,981	15,796,053	19,630,124	23,464,196
Unrecovered Investment -- Book	37,503,641	85,667,502	157,859,140	164,552,444	164,552,444	164,552,444	164,552,444	164,552,444	164,552,444
Book Depreciation	-	-	459,765	3,834,072	3,834,072	3,834,072	3,834,072	3,834,072	3,834,072
Unrecovered Investment -- Tax total	37,503,641	85,667,502	157,859,140	164,552,444	164,552,444	164,552,444	164,552,444	164,552,444	164,552,444
Tax Depreciation	-	-	5,919,718	11,879,041	10,987,167	10,164,404	9,400,881	8,696,597	8,043,323
Allowed Rate of Return	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%
Book Depreciation expense total	-	-	459,765	3,834,072	3,834,072	3,834,072	3,834,072	3,834,072	3,834,072
Tax Depreciation expense total	-	-	5,919,718	11,879,041	10,987,167	10,164,404	9,400,881	8,696,597	8,043,323
Annual Property Tax Rate	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%
Deferred Tax Balance	-	-	1,949,749	2,872,858	2,554,370	2,260,562	1,987,908	1,736,408	1,503,124
Revenue Recovery on Capital Expenditure to date									
Eligible Plant, cumulative capital expenditures	37,503,641	85,667,502	157,859,140	164,552,444	164,552,444	164,552,444	164,552,444	164,552,444	164,552,444
Less. Retired Plant	-	-	-	-	-	-	-	-	-
Less: Accumulated Depreciation	-	-	(459,765)	(4,293,837)	(8,127,909)	(11,961,981)	(15,796,053)	(19,630,124)	(23,464,196)
Plus: Accumulated Depreciation on Retired Plant	-	-	-	-	-	-	-	-	-
Less: Deferred Tax Balance	-	-	(1,949,749)	(4,822,608)	(7,376,978)	(9,637,540)	(11,625,447)	(13,361,855)	(14,864,978)
Plus: Deferred Tax Balance on Retired Plant	-	-	-	-	-	-	-	-	-
Environmental Compliance Rate Base	37,503,641	85,667,502	155,449,626	155,436,000	149,047,558	142,952,924	137,130,944	131,560,465	126,223,269
Rate of return	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%
Return on Environmental Compliance Rate Base	$ 4,138,884	$ 9,454,225	$ 17,155,347	$ 17,153,843	$ 16,448,817	$ 15,776,216	$ 15,133,706	$ 14,518,950	$ 13,929,940
Operating Expenses	8,692	1,276,696	2,183,254	12,112,005	12,354,245	12,601,330	12,853,356	13,110,424	13,372,632
Annual Depreciation expense	-	-	459,765	3,834,072	3,834,072	3,834,072	3,834,072	3,834,072	3,834,072
Less depreciation on retired plant	-	-	-	-	-	-	-	-	-
Annual Property Tax expense	223	56,255	128,501	236,099	240,388	234,637	228,886	223,135	217,383
Total OE	$ 8,915	$ 1,332,951	$ 2,771,520	$ 16,182,176	$ 16,428,705	$ 16,670,039	$ 16,916,314	$ 17,167,630	$ 17,424,087
Total E(m) - Project	4,147,799	10,787,176	19,926,866	33,336,019	32,877,522	32,446,255	32,050,020	31,686,580	31,354,027

Revenue Requirements Project Detail
2011 Amended Plan - KU Project 35

	2012	2013	2014	October 2015	2016	2017	2018	2019	2020
In-Service				1	2	3	4	5	6
Ghent 3									
CapEx - GH3 PM Control Systems-SAM Mitigation-SCR Turn-down	$ 4,809,001	$ 47,890,171	$ 56,057,325	$ 84,049,087	$ 3,898,032	$ -	$ -	$ -	$ -
Accumulated Expenditures	$ 6,116,717	$ 54,006,888	$ 110,064,213	$ 194,113,300	$ 198,011,331	$ 198,011,331	$ 198,011,331	$ 198,011,331	$ 198,011,331
Book Depreciation rate, per year	0.000%	0.000%	0.000%	2.630%	2.630%	2.630%	2.630%	2.630%	2.630%
Tax Depreciation rate, per year	0.000%	0.000%	0.000%	3.750%	7.219%	6.677%	6.177%	5.713%	5.285%
Income tax rate	35.71%	35.71%	35.71%	35.71%	35.71%	35.71%	35.71%	35.71%	35.71%
Deferred Tax Balance	-	-	-	2,219,616	5,464,490	8,326,118	10,834,196	13,014,181	14,891,527
Book Accumulated Depreciation Balance	-	-	-	1,063,579	6,271,277	11,478,975	16,686,673	21,894,371	27,102,069
Unrecovered Investment -- Book	6,116,717	54,006,888	110,064,213	194,113,300	198,011,331	198,011,331	198,011,331	198,011,331	198,011,331
Book Depreciation	-	-	-	1,063,579	5,207,698	5,207,698	5,207,698	5,207,698	5,207,698
Unrecovered Investment -- Tax total	6,116,717	54,006,888	110,064,213	194,113,300	198,011,331	198,011,331	198,011,331	198,011,331	198,011,331
Tax Depreciation	-	-	-	7,279,249	14,294,438	13,221,217	12,231,160	11,312,387	10,464,899
Allowed Rate of Return	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%
Book Depreciation expense total	-	-	-	1,063,579	5,207,698	5,207,698	5,207,698	5,207,698	5,207,698
Tax Depreciation expense total	-	-	-	7,279,249	14,294,438	13,221,217	12,231,160	11,312,387	10,464,899
Annual Property Tax Rate	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%
Deferred Tax Balance	-	-	-	2,219,616	3,244,875	2,861,627	2,508,078	2,179,985	1,877,346
Revenue Recovery on Capital Expenditure to date									
Eligible Plant, cumulative capital expenditures	6,116,717	54,006,888	110,064,213	194,113,300	198,011,331	198,011,331	198,011,331	198,011,331	198,011,331
Less: Retired Plant	-	-	-	-	-	-	-	-	-
Less: Accumulated Depreciation	-	-	-	(1,063,579)	(6,271,277)	(11,478,975)	(16,686,673)	(21,894,371)	(27,102,069)
Plus: Accumulated Depreciation on Retired Plant	-	-	-	-	-	-	-	-	-
Less: Deferred Tax Balance	-	-	-	(2,219,616)	(5,464,490)	(8,326,118)	(10,834,196)	(13,014,181)	(14,891,527)
Plus: Deferred Tax Balance on Retired Plant	-	-	-	-	-	-	-	-	-
Environmental Compliance Rate Base	6,116,717	54,006,888	110,064,213	190,830,105	186,275,564	178,206,238	170,490,462	163,102,779	156,017,735
Rate of return	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%
Return on Environmental Compliance Rate Base	$ 675,038	$ 5,960,174	$ 12,146,634	$ 21,059,919	$ 20,557,282	$ 19,666,755	$ 18,815,246	$ 17,999,945	$ 17,218,043
Operating Expenses	-	642,953	4,721,847	6,363,418	17,537,222	17,887,966	18,245,725	18,610,640	18,982,853
Annual Depreciation expense	-	-	-	1,063,579	5,207,698	5,207,698	5,207,698	5,207,698	5,207,698
Less depreciation on retired plant	-	-	-	-	-	-	-	-	-
Annual Property Tax expense	1,962	9,175	81,010	165,096	289,575	287,610	279,799	271,987	264,175
Total OE	$ 1,962	$ 652,128	$ 4,802,857	$ 7,592,093	$ 23,034,494	$ 23,383,274	$ 23,733,222	$ 24,090,325	$ 24,454,726
Total E(m) - Project	677,000	6,612,303	16,949,491	28,652,013	43,591,777	43,050,030	42,548,468	42,090,270	41,672,769

Revenue Requirements Project Detail
2011 Amended Plan - KU Project 35

				December					
	2012	2013	2014	2015	2016	2017	2018	2019	2020
In-Service				1	2	3	4	5	6
Ghent 4									
CapEx - GH4 PM Control Systems-SAM Mitigation-SCR Turn-down	$ 4,321,807	$ 35,116,729	$ 57,307,535	$ 77,571,909	$ 8,984,440	$ -	$ -	$ -	$ -
Accumulated Expenditures	$ 5,780,544	$ 40,897,273	$ 98,204,808	$ 175,776,717	$ 184,761,157	$ 184,761,157	$ 184,761,157	$ 184,761,157	$ 184,761,157
Book Depreciation rate, per year	0.000%	0.000%	0.000%	2.790%	2.790%	2.790%	2.790%	2.790%	2.790%
Tax Depreciation rate, per year	0.000%	0.000%	0.000%	3.750%	7.219%	6.677%	6.177%	5.713%	5.285%
Income tax rate	35.71%	35.71%	35.71%	35.71%	35.71%	35.71%	35.71%	35.71%	35.71%
Deferred Tax Balance	-	-	-	2,280,900	5,203,075	7,767,648	10,002,330	11,930,873	13,577,029
Book Accumulated Depreciation Balance	-	-	-	204,340	5,359,177	10,514,013	15,668,849	20,823,686	25,978,522
Unrecovered Investment – Book	5,780,544	40,897,273	98,204,808	175,776,717	184,761,157	184,761,157	184,761,157	184,761,157	184,761,157
Book Depreciation	-	-	-	204,340	5,154,836	5,154,836	5,154,836	5,154,836	5,154,836
Unrecovered Investment – Tax total	5,780,544	40,897,273	98,204,808	175,776,717	184,761,157	184,761,157	184,761,157	184,761,157	184,761,157
Tax Depreciation	-	-	-	6,591,627	13,337,908	12,336,502	11,412,697	10,555,405	9,764,627
Allowed Rate of Return	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%
Book Depreciation expense total	-	-	-	204,340	5,154,836	5,154,836	5,154,836	5,154,836	5,154,836
Tax Depreciation expense total	-	-	-	6,591,627	13,337,908	12,336,502	11,412,697	10,555,405	9,764,627
Annual Property Tax Rate	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%
Deferred Tax Balance	-	-	-	2,280,900	2,922,175	2,564,573	2,234,682	1,928,543	1,646,156
Revenue Recovery on Capital Expenditure to date									
Eligible Plant, cumulative capital expenditures	5,780,544	40,897,273	98,204,808	175,776,717	184,761,157	184,761,157	184,761,157	184,761,157	184,761,157
Less: Retired Plant	-	-	-	-	-	-	-	-	-
Less: Accumulated Depreciation	-	-	-	(204,340)	(5,359,177)	(10,514,013)	(15,668,849)	(20,823,686)	(25,978,522)
Plus: Accumulated Depreciation on Retired Plant	-	-	-	-	-	-	-	-	-
Less: Deferred Tax Balance	-	-	-	(2,280,900)	(5,203,075)	(7,767,648)	(10,002,330)	(11,930,873)	(13,577,029)
Plus: Deferred Tax Balance on Retired Plant	-	-	-	-	-	-	-	-	-
Environmental Compliance Rate Base	5,780,544	40,897,273	98,204,808	173,291,476	174,198,905	166,479,496	159,089,978	152,006,599	145,205,606
Rate of return	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%
Return on Environmental Compliance Rate Base	$ 637,938	$ 4,513,404	$ 10,837,836	$ 19,124,365	$ 19,224,508	$ 18,372,598	$ 17,557,094	$ 16,775,376	$ 16,024,821
Operating Expenses	-	3,578,918	5,256,715	5,848,876	17,391,503	17,739,333	18,094,120	18,456,002	18,825,122
Annual Depreciation expense	-	-	-	204,340	5,154,836	5,154,836	5,154,836	5,154,836	5,154,836
Less depreciation on retired plant	-	-	-	-	-	-	-	-	-
Annual Property Tax expense	2,188	8,671	61,346	147,307	263,359	269,103	261,371	253,638	245,906
Total OE	$ 2,188	$ 3,587,589	$ 5,318,061	$ 6,200,524	$ 22,809,698	$ 23,163,272	$ 23,510,327	$ 23,864,477	$ 24,225,865
Total E(m) - Project	640,126	8,100,993	16,155,897	25,324,888	42,034,206	41,535,870	41,067,421	40,639,852	40,250,686