LG&E®
a PPL company

Hand Delivery

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

Louisville Gas and Electric Company
State Regulation and Rates
220 West Main Street
P.O. Box 32010
Louisville, Kentucky 40232
www.lge-ku.com

Robert M. Conroy
Director - Rates
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June 1, 2011

RE: *In the Matter of: The Application of Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Approval of Its 2011 Compliance Plan for Recovery by Environmental Surcharge*
Case No. 2011-00162

Dear Mr. DeRouen:

Enclosed please find an original and ten (10) copies of Louisville Gas and Electric Company's ("LG&E") Application and Testimonies in the above-referenced docket.

This filing includes:

- LG&E's Application,
- Statutory Notice,
- Certificate of Notice,
- Lonnie E. Bellar's Testimony,
- John N. Voyles's Testimony and Exhibits,
- Gary H. Revlett's Testimony,
- 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 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 LOUISVILLE GAS AND ELECTRIC COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	)	CASE NO. 2011-00162

APPLICATION

Louisville Gas and Electric Company ("LG&E"), 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 LG&E Certificates of Public Convenience and Necessity ("CPCNs") to: remove the current Flue Gas Desulfurization ("FGD") systems on Mill Creek Generating Station ("Mill Creek") Units 1 and 2 and build a single new FGD to serve both units; build a new FGD to serve Mill Creek Unit 4; remove the existing FGD at Mill Creek Unit 3 and tie Unit 3 into the current Unit 4 FGD; and build Particulate Matter Control Systems to serve all the generating units at Mill Creek and Trimble County Generating Station Unit 1 ("TC1"). LG&E further petitions the Commission for an order approving an amended compliance plan for the purpose of recovering the costs of these and other new and additional pollution-control facilities through its Environmental Surcharge tariff ("2011 Environmental Compliance Plan"). These projects are required for LG&E to comply with the federal Clean Air Act as amended ("CAAA"), the U.S. Environmental Protection Agency's ("EPA's") new 1-hour sulfur dioxide ("SO_2") National Ambient Air Quality Standard ("NAAQS"), the proposed Clean Air Transport Rule ("CATR"), the proposed national emission standards for hazardous air pollutants ("HAPs Rule"), and other environmental requirements that apply to LG&E facilities used in the production of energy from coal. In support of this Application, LG&E states as follows:

1. Address: The applicant's full name and post office address is: Louisville Gas and Electric Company, 220 West Main Street, Post Office Box 32010, Louisville, Kentucky 40202.

2. Articles of Incorporation: A certified copy of LG&E's 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. LG&E is a public utility, as defined in KRS 278.010(3)(a), engaged in the electric and gas business. LG&E generates and purchases electricity, and distributes and sells electricity at retail in Jefferson County and portions of Bullitt, Hardin, Henry, Meade, Oldham, Shelby, Spencer, and Trimble Counties. LG&E also purchases, stores, and transports natural gas and distributes and sells natural gas at retail in Jefferson County and portions of Barren, Bullitt, Green, Hardin, Hart, Henry, Larue, Marion, Meade, Metcalfe, Nelson, Oldham, Shelby, Spencer, Trimble, and Washington Counties.

Request for Certificates of Public Convenience and Necessity

FGD Construction and Removal at the Mill Creek Generating Station

4. LG&E proposes to remove the current FGDs on Mill Creek Units 1, 2, and 3, build two new FGDs (one to serve Mill Creek Units 1 and 2, another to serve Mill Creek Unit 4), and tie Mill Creek Unit 3 into the existing (and upgraded) Mill Creek Unit 4 FGD.

5. Statement of Need (807 KAR 5:001 § 9(2)(a)): In support of LG&E's contention that the public convenience and necessity requires the proposed FGD construction at all four Mill

Creek units, LG&E states that on July 6, 2010, the EPA issued its proposed CATR, aimed at reducing air quality problems in the eastern United States, to replace the former Clean Air Interstate Rule ("CAIR"). CATR is intended to assist certain states with meeting the existing NAAQS by limiting the interstate transportation of sulfur dioxide ("SO_2") and nitrogen oxide ("NO_x").

In addition, EPA finalized the new 1-hour SO_2 NAAQS in June 2010, which required the state/local air pollution control agencies to develop implementation plans for any non-attainment area. Jefferson County has already begun recording SO_2 levels in excess of the new 1-hour NAAQS. According to the CAAA for NAAQS, the Louisville Metro Air Pollution Compliance District ("LMAPCD") must declare the county to be in "non-attainment" of the standard, which the EPA must confirm within 1 year. After that, the LMAPCD must file, and the EPA must approve, a plan to bring the county back into attainment. Emission sources must then take actions to reduce SO_2 emissions consistent with the approved plan. As the largest SO_2 emitter in Jefferson County, the Mill Creek Station will need to reduce its SO_2 emissions, which has been true of all the previous non-attainment plans developed by the LMAPCD.

Building this new FGD technology is the most cost-effective means of complying with existing and proposed law.

6. <u>Description of Proposed Construction (807 KAR 5:001 § 9(2)(c))</u>: LG&E is requesting three FGD-related CPCNs: one to remove the current Mill Creek Units 1 and 2 FGDs and to build a new FGD to serve both units; one to remove the current Mill Creek Unit 3 FGD and to tie Unit 3 into the existing Mill Creek Unit 4 FGD (which will be upgraded); and one to build a new FGD to serve Mill Creek Unit 4. These projects consist of new construction and changes to existing certificated facilities that require 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.

LG&E proposes to begin building the new FGD to serve Units 1 and 2 in early 2012, and the work should be complete by mid-2015. Once the new FGD is in service, the process to remove the existing Mill Creek Units 1 and 2 FGDs will begin.

LG&E proposes to begin initial demolition activities related to the construction (e.g., removing the thickener tank south of Unit 4 and several warehouses and shops) in the fall of 2011, and to begin building Unit 4's new FGD in early 2012, and the work should be complete by late 2014.

LG&E proposes to begin refurbishing the existing Unit 4 FGD after tying Unit 4 into its new FGD. LG&E plans to place Unit 4 back into service in late 2014, with Unit 3 being placed back into service (after being tied into the refurbished former Unit 4 FGD) in late 2015.

For these reasons, LG&E is requesting that the Commission issue its CPCNs by December 1, 2011.

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, LG&E will submit to the LMAPCD requests to modify existing Title V operating permits to reflect all of the proposed Mill Creek FGD construction. LG&E will file applications for the needed Title V permit changes later this summer, and will file a copy of the applications with the Commission when they are available. LG&E will also seek any applicable construction permits.

8. Area Maps (807 KAR 5:001 § 9(2)(d)): The required area maps showing the location of the proposed construction for each of the three requested FGD-related CPCNs are attached as Application Exhibit 2.

9. Financing Plans (807 KAR 5:001 § 9(2)(e)): The projected capital cost of removing the existing Mill Creek Units 1 and 2 FGDs and building a single new FGD to serve the units is $354 million. The projected capital cost of removing the existing Mill Creek Unit 3 FGD and of tying Mill Creek Unit 3 into, and upgrading, the existing Mill Creek Unit 4 FGD is $73 million. Finally, the projected capital cost of building a new FGD to serve Mill Creek Unit 4 is $218 million. LG&E'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. Final action on this Application is requested on December 1, 2011, to allow LG&E to begin procurement of materials and equipment under the proposed construction schedule.

Particulate Matter Control Systems at Mill Creek and Trimble County Unit 1

12. LG&E proposes to build a Particulate Matter Control System for each of the four generating units at Mill Creek and for TC1. 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 LG&E's 2006 Plan).[1]

13. Statement of Need (807 KAR 5:001 § 9(2)(a)): In support of LG&E's contention that the public convenience and necessity requires the proposed construction of Particulate Matter Control Systems to serve all units at Mill Creek and TC1, LG&E 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, LG&E will have to be in full compliance with the HAPs Rule no later than November 16, 2015 (assuming the final rule is timely issued).

Building these Particulate Matter Control Systems is the most cost-effective means of complying with the HAPs Rule.

14. Description of Proposed Construction (807 KAR 5:001 § 9(2)(c)): LG&E is requesting a CPCN to construct a Particulate Matter Control System at each of the Mill Creek units and TC1 (i.e., LG&E is requesting five CPCNs for Particulate Matter Control Systems). (Particulate Matter Control Systems are described in Paragraph 12 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

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[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).

testimony of Mr. Voyles as Exhibit JNV-2, contains the engineering work papers related to this construction.

LG&E proposes to begin installing the Particulate Matter Control Systems to serve all the Mill Creek units in early 2012, and the work should be complete by mid-2015 for Units 1 and 2, late 2015 for Unit 3, and late 2014 for Unit 4. For TC1, LG&E proposes to begin installing the Particulate Matter Control System in mid 2013, and the work should be complete by late 2015.

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

15. Permits or Franchises (807 KAR 5:001 § 9(2)(b)): As discussed in the testimony of Mr. Revlett, LG&E will submit to the LMAPCD (for the Mill Creek units) and the Kentucky Natural Resources and Environmental Protection Cabinet Division for Air Quality (for TC1) requests to modify the existing Title V operating permits to reflect the installation of the proposed Particulate Matter Control Systems. LG&E will file applications for Title V permit changes later this summer, and will file a copy of the applications with the Commission when they are available. LG&E will also seek any applicable construction permits.

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

Financing Plans (807 KAR 5:001 § 9(2)(e)): The total projected capital cost of these facilities at Mill Creek (part of Project 26) is $604 million: $155 million for Unit 1, $151 million for Unit 2, $143 million for Unit 3, and $155 million for Unit 4. The total projected capital cost of these facilities at TC1 (Project 27) is $124 million.

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

17. 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.

18. 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 LG&E's taking quick but carefully analyzed action in response to these new requirements. LG&E therefore respectfully asks the Commission to issue the requested CPCNs on December 1, 2011, to permit LG&E 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 LG&E's 2011 Environmental Compliance Plan for Recovery by Environmental Surcharge

19. This Application and supporting testimony and exhibits are available for public inspection at each LG&E 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.

20. Pursuant to KRS 278.183, LG&E 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."

21. LG&E is adding two new projects. The new projects will enable LG&E's Mill Creek and Trimble County Generating Stations to comply with the Clean Air Act and other current and proposed environmental laws, regulations, and enforcement actions. 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 and to the testimony of Mr. Voyles as Exhibit JNV-1. Mr. Revlett's testimony presents LG&E'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:

- Project No. 26 (Mill Creek): Removing the existing FGDs for Units 1 and 2 and building a single new to serve both units; constructing a new FGD for Unit 4; removing the existing Unit 3 FGD and tying Unit 3 into the existing Unit 4 FGD; constructing Particulate Matter Control Systems to serve all four units; modifying systems on Units 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 upgrading the Unit 4 SCR.
- Project No. 27 (Trimble County): Constructing a Particulate Matter Control System for Unit 1.

The total capital cost of these new projects to the Compliance Plan is estimated to be approximately $1.4 billion.

As described in Robert M. Conroy's testimony, LG&E proposes to report the SAM-sorbent-O&M costs of TC1's existing separate SAM mitigation system as part of Project 27's SAM-sorbent (baghouse lime) O&M costs. Also, the Commission approved separate SAM mitigation systems for Mill Creek Units 3 and 4 as part of LG&E's 2006 Plan (Project 19), though those systems have not yet been installed (but will be installed in the near future). LG&E proposes to report the SAM-sorbent-O&M costs of those systems as part of Project 26's SAM-sorbent (baghouse lime) O&M costs.

22. 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 LG&E'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. Mr. Bellar's testimony also states the reasons LG&E is seeking CPCNs for certain ECR projects, the reasons for requesting the projects themselves, and how LG&E 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 LG&E'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 LG&E's 2011 Plan. Mr. Revlett describes the pertinent statutes, rules, or regulations requiring LG&E to take action.
- Charles R. Schram, Director, Energy Planning, Analysis and Forecasting, presents testimony on the cost-effectiveness of the projects in LG&E's 2011 Plan, and presents as an exhibit the cost-benefit study LG&E performed.
- Shannon L. Charnas, Director, Accounting and Regulatory Reporting, presents testimony affirming that the costs for which LG&E is seeking recovery through its Environmental Surcharge tariff are not included in base rates, and describes the accounting associated with the projects in LG&E's 2011 Plan, all consistent with the Commission's prior orders.
- Robert M. Conroy, Director, Rates, presents LG&E's proposed Electric Rate Schedule ECR and corresponding monthly reporting requirements, and presents testimony affirming that the calculation of LG&E's environmental surcharge will comply with all previous Commission Orders. Mr. Conroy also presents the revisions to the monthly ECR reporting forms that LG&E proposes, and explains why the revisions to the forms are appropriate. In addition, Mr. Conroy discusses the bill impact on LG&E's customers.

23. LG&E is proposing some minor clarifying changes to its Environmental Cost Recovery Surcharge tariff, P.S.C. Electric No. 8, Original Sheet No. 87, *Adjustment Clause ECR*, but no substantive changes to the terms or conditions thereof. LG&E 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, Louisville Gas and Electric Company respectfully asks the Commission to enter an order on December 1, 2011: (1) granting LG&E Certificates of Public Convenience and Necessity to remove the existing Mill Creek Units 1 and 2 FGDs and to build a single new FGD to serve the units, to build a new FGD at Mill Creek Unit 4, to remove the existing Mill Creek Unit 3 FGD and to tie Unit 3 into, and to upgrade, Unit 4's existing FGD, and to allow for construction of Particulate Matter Control Systems at Mill Creek Units 1, 2, 3, and 4 and Trimble County Unit 1; (2) approving the new projects to LG&E'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 LG&E 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 Louisville Gas and Electric 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 Louisville Gas and Electric Company

Statutory Notice

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	)	**CASE NO. 2011-00162**

STATUTORY NOTICE

Louisville Gas and Electric Company ("LG&E"), 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 in Jefferson County and portions of Bullitt, Hardin, Henry, Meade, Oldham, Shelby, Spencer, and Trimble Counties and retail natural gas service in Jefferson County and portions of Barren, Bullitt, Green, Hardin, Hart, Henry, Larue, Marion, Meade, Metcalfe, Nelson, Oldham, Shelby, Spencer, Trimble, and Washington Counties within the Commonwealth of Kentucky.

Pursuant to KRS 278.183, and as required, KRS 278,020(1), LG&E hereby gives notice to the Commission that, on this 1st day of June 2011, it files herewith its application to issue an order granting LG&E Certificates of Public Convenience and Necessity to: build a single flue gas desulfurization ("FGD") unit to serve Mill Creek Units 1 and 2 and remove the existing FGDs for those units; build an FGD at Mill Creek Unit 4; remove the existing FGD at Mill Creek Unit 3 and tie Unit 3 into the existing Unit 4 FGD; build baghouses with powdered activated carbon ("PAC") injection and lime injection systems at Mill Creek Units 1, 2, 3, and 4; and build a baghouse with a PAC injection system and a lime injection system at Trimble County Unit 1.

The application further seeks approval of an amended compliance plan for purposes of recovering the costs of new pollution control facilities through its Electric Rate Schedule ECR.

Notice is further given that LG&E proposes to adjust its Electric 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 Louisville Gas and Electric 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

Allyson K Sturgeon
Counsel for Louisville Gas and Electric Company

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, 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 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 LOUISVILLE GAS AND ELECTRIC COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	))))))	**CASE NO. 2011-00162**

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 Louisville Gas and Electric Company ("LG&E" 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 for an order granting LG&E Certificates of Public Convenience and Necessity to: build a single flue gas desulfurization ("FGD") unit to serve Mill Creek Units 1 and 2 and remove the existing FGDs for those units; build an FGD at Mill Creek Unit 4; remove the existing FGD at Mill Creek Unit 3 and tie Unit 3 into the existing Unit 4 FGD; build baghouses with powdered activated carbon ("PAC") injection and lime injection systems at Mill Creek Units 1, 2, 3, and 4; and build a baghouse with a PAC injection system and a lime injection system at Trimble County Unit 1. The application further seeks approval of an amended compliance plan for purposes of recovering the costs of new pollution control facilities through its Electric 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, LG&E will issue and file its proposed Electric Rate Schedule ECR, P.S.C. Electric No. 8, 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 701 South Ninth Street, Louisville, KY 40203 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 LG&E'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, Louisville Gas and Electric 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 Louisville Gas and Electric 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
Louisville Gas and Electric 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 Walters (SEAL)
Notary Public

My Commission Expires:
9/11/2012

APPENDIX A

NOTICE TO CUSTOMERS OF
LOUISVILLE GAS AND ELECTRIC COMPANY

RECOVERY BY ENVIRONMENTAL SURCHARGE OF LOUISVILLE GAS AND ELECTRIC'S 2011 ENVIRONMENTAL COMPLIANCE PLAN

PLEASE TAKE NOTICE that on June 1, 2011, Louisville Gas and Electric Company ("LG&E") will file with the Kentucky Public Service Commission ("Commission") in Case No. 2011-00162, an Application pursuant to Kentucky Revised Statute 278.183 for approval of an amended compliance plan ("LG&E'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 LG&E's Electric Rate Schedule ECR, also known as the environmental cost recovery surcharge.

Federal, state, and local environmental regulations require LG&E to build and upgrade equipment and facilities to operate in an environmentally sound manner. Specifically, LG&E is seeking Commission approval of Certificates of Public Convenience and Necessity ("CPCN") to build new Flue Gas Desulfurization systems ("FGDs") for Units 1, 2, and 4 at the Mill Creek Generating Station in Jefferson County, Kentucky; to remove the existing Mill Creek Units 1, 2, and 3 FGDs; to upgrade the existing Mill Creek Unit 4 FGD and tie Unit 3 into the existing Unit 4 FGD; and to install Particulate Matter Control Systems to serve all units at the Mill Creek Generating Station and Unit 1 at the Trimble County Generating Station near Wises Landing in Trimble County, Kentucky. Additionally, LG&E is seeking recovery of costs associated with these environmental projects, which are necessary for compliance with the federal Clean Air Act, and other current or proposed environmental laws and regulations, as implemented by the relevant government agencies. These additional projects primarily relate to installing FGDs and Particulate Matter Control Systems on all units at the Mill Creek Generating Station, and installing a Particulate Matter Control System on Unit 1 at the Trimble County Generating Station and other pollution control facilities. The capital cost of the new pollution control facilities for which LG&E will seek cost recovery at this time is estimated to be $1.4 billion. Additional operation and maintenance expenses will be incurred for these projects and are costs that LG&E is requesting to recover through the environmental surcharge in its application.

The impact on LG&E's electric customers is estimated to be a 2.3% increase in 2012 with a maximum increase of 19.2% in 2016. For a LG&E residential electric customer using 1,000 kilowatt hours per month, the initial monthly increase is expected to be $1.96 during 2012, with the maximum monthly increase expected to be $16.33 during 2016.

The Environmental Surcharge Application described in this Notice is proposed by LG&E. However, the Public Service Commission may issue an order modifying or denying LG&E'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. 2011-00162. 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 Louisville Gas and Electric 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 LG&E's website (http://www.lge-ku.com) and at LG&E's offices where bills are paid after June 1, 2011.

APPENDIX B

Dear LG&E Customer:

To comply with existing and new federal environmental laws and regulations, LG&E must continue to invest in additional pollution control facilities. Currently, LG&E 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 electric customers through the existing Environmental Surcharge billing factor. LG&E estimates that the initial impact would be an increase in the environmental surcharge of $1.96 per month for a residential electric 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.

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Exhibit 1-2011 Plan

LOUISVILLE GAS AND ELECTRIC COMPANY
2011 ENVIRONMENTAL COMPLIANCE PLAN

Project	Air Pollutant or Waste/By-Product To Be Controlled	Control Facility	Generating Station	Environmental Regulation*	Environmental Permit*	Actual or Scheduled Completion	Actual (A) or Estimated (E) Projected Capital Cost ($Million)
26	SO_2, SO_3, NO_x, Hg and Particulate	Flue Gas Desulfurization, Baghouse with Powdered Activated Carbon Injection, SCR Turn-Down (Unit 3 & 4), and SCR upgrade (Unit 4), Sulfuric Acid Mist Mitigation	Mill Creek Unit 1	Clean Air Act (1990), NAAQS, HAPS and CATR	Title V Permit	2015	$331.41 (E)
			Mill Creek Unit 2			2015	$328.02 (E)
			Mill Creek Unit 3			2015	$223.06 (E)
			Mill Creek Unit 4			2012-2014	$385.73 (E)
27	NO_x, Hg and Particulate	Baghouse with Powdered Activated Carbon Injection	Trimble County Unit 1	Clean Air Act (1990), HAPS and CATR	Title V Permit	2012	$123.75 (E)
							$1,391.97

* Sponsored by Witness Revlett

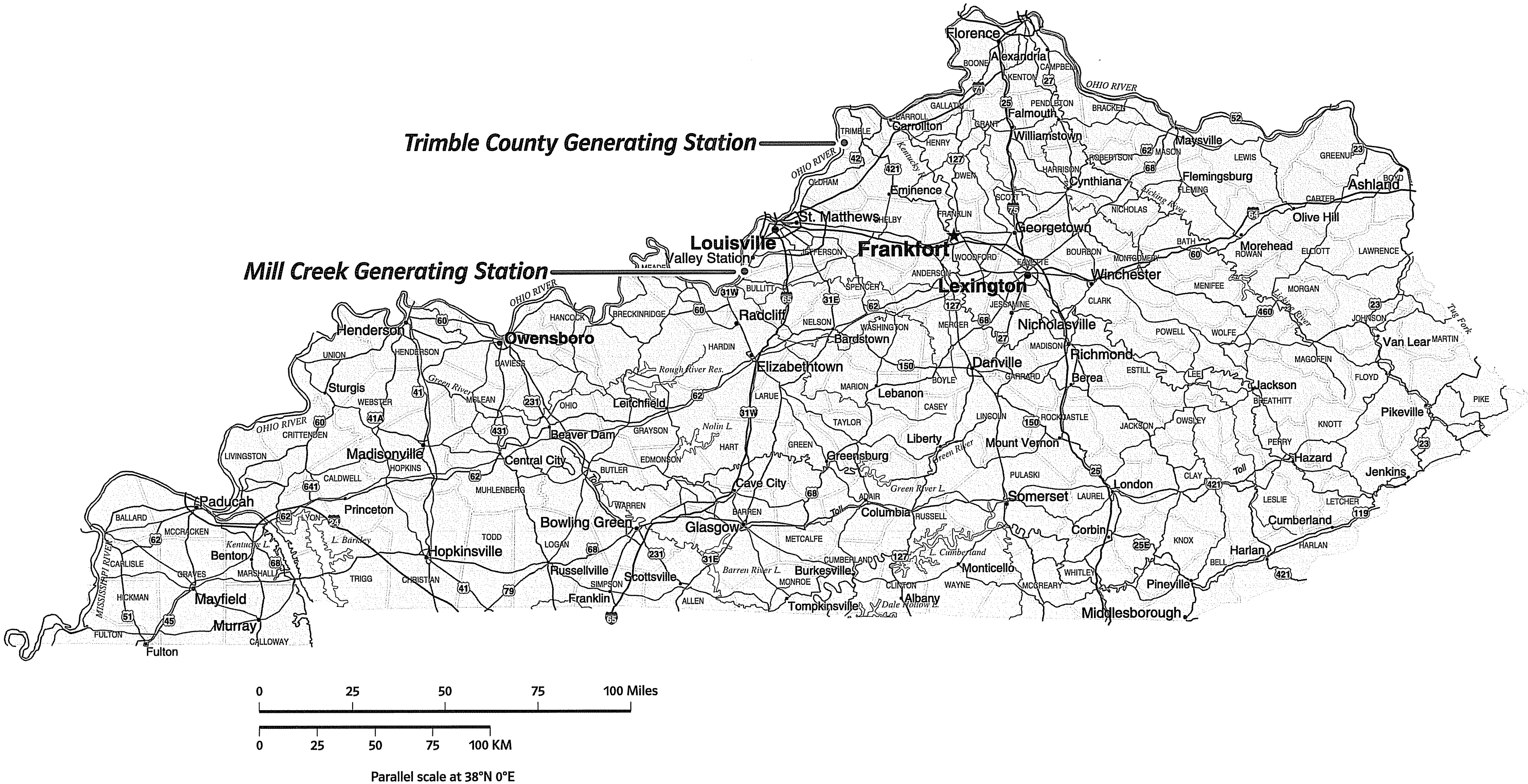
LOUISVILLE GAS AND ELECTRIC COMPANY
2011 ENVIRONMENTAL COMPLIANCE PLAN

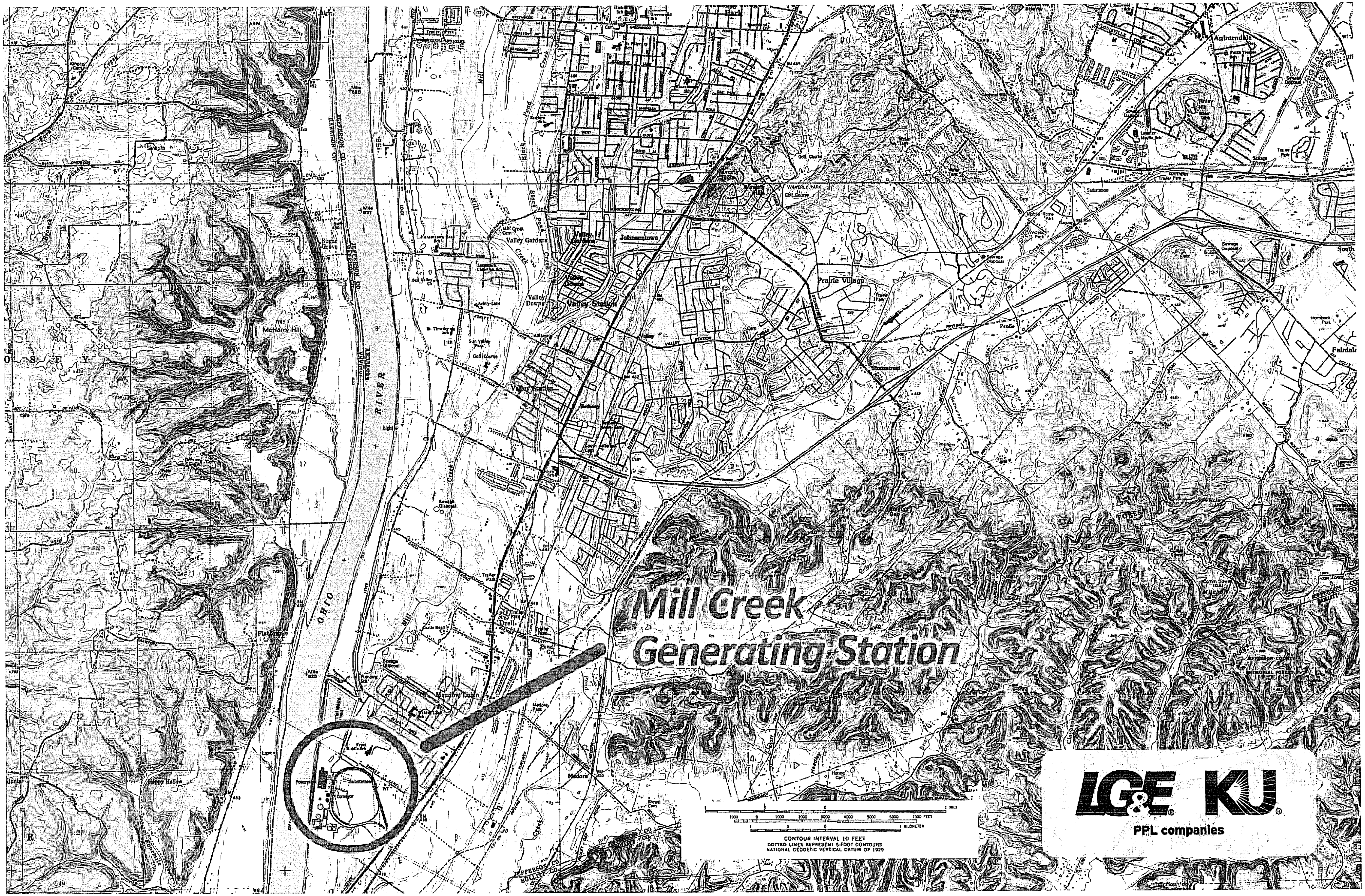
Project	Air Pollutant or Waste/By-Product To Be Controlled	Control Facility	Generating Station	Estimated Annual Operations and Maintenance Costs (Through 2020)								
				2012	2013	2014	2015	2016	2017	2018	2019	2020
26	SO_2, SO_3, NO_x, Hg and Particulate	Flue Gas Desulfurization, Baghouse with Powdered Activated Carbon Injection, SCR Turn-down (Unit 3 & 4), and SCR upgrade (Unit 4), Sulfuric Acid Mist Mitigation	Mill Creek Unit 1	$ -	$ -	$ -	$ 5,044,845	$ 8,806,961	$ 9,022,738	$ 9,242,832	$ 9,467,327	$ 9,696,312
			Mill Creek Unit 2	$ -	$ -	$ -	$ 6,454,427	$ 9,695,385	$ 9,920,850	$ 10,150,825	$ 10,385,398	$ 10,624,664
			Mill Creek Unit 3	$ -	$ 1,693,407	$ 3,447,748	$ 4,857,328	$ 13,019,344	$ 13,333,943	$ 13,654,833	$ 13,982,142	$ 14,315,996
			Mill Creek Unit 4	$ -	$ -	$ 3,631,737	$ 15,519,305	$ 15,881,381	$ 16,250,699	$ 16,627,402	$ 17,011,640	$ 17,403,563
27	NO_x, Hg and Particulate	Baghouse with Powdered Activated Carbon Injection	Trimble County Unit 1	$ -	$ -	$ -	$ 3,732,365	$ 7,614,024	$ 7,766,305	$ 7,921,631	$ 8,080,064	$ 8,241,665

Exhibit 2-Maps

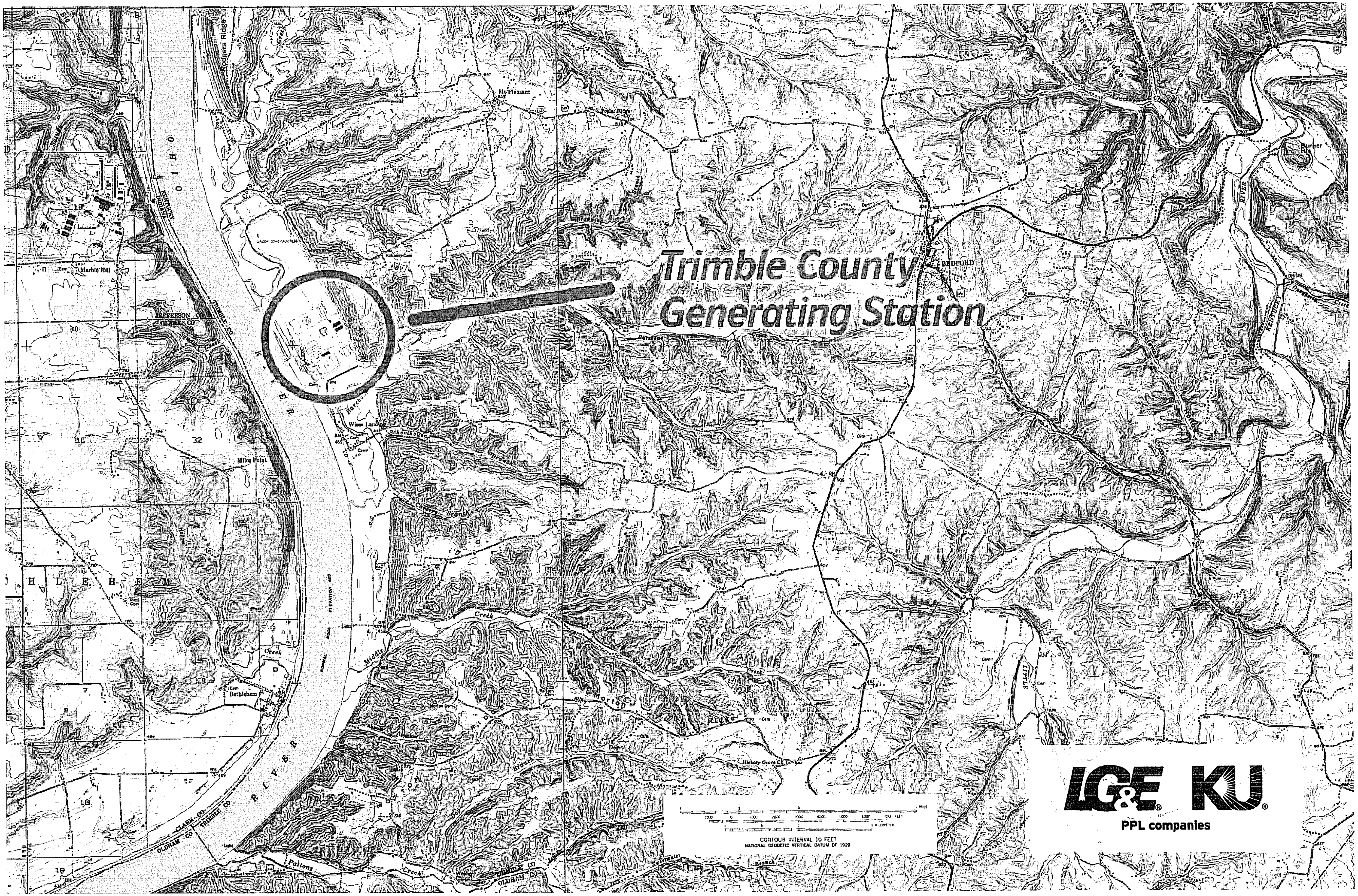
LG&E KU

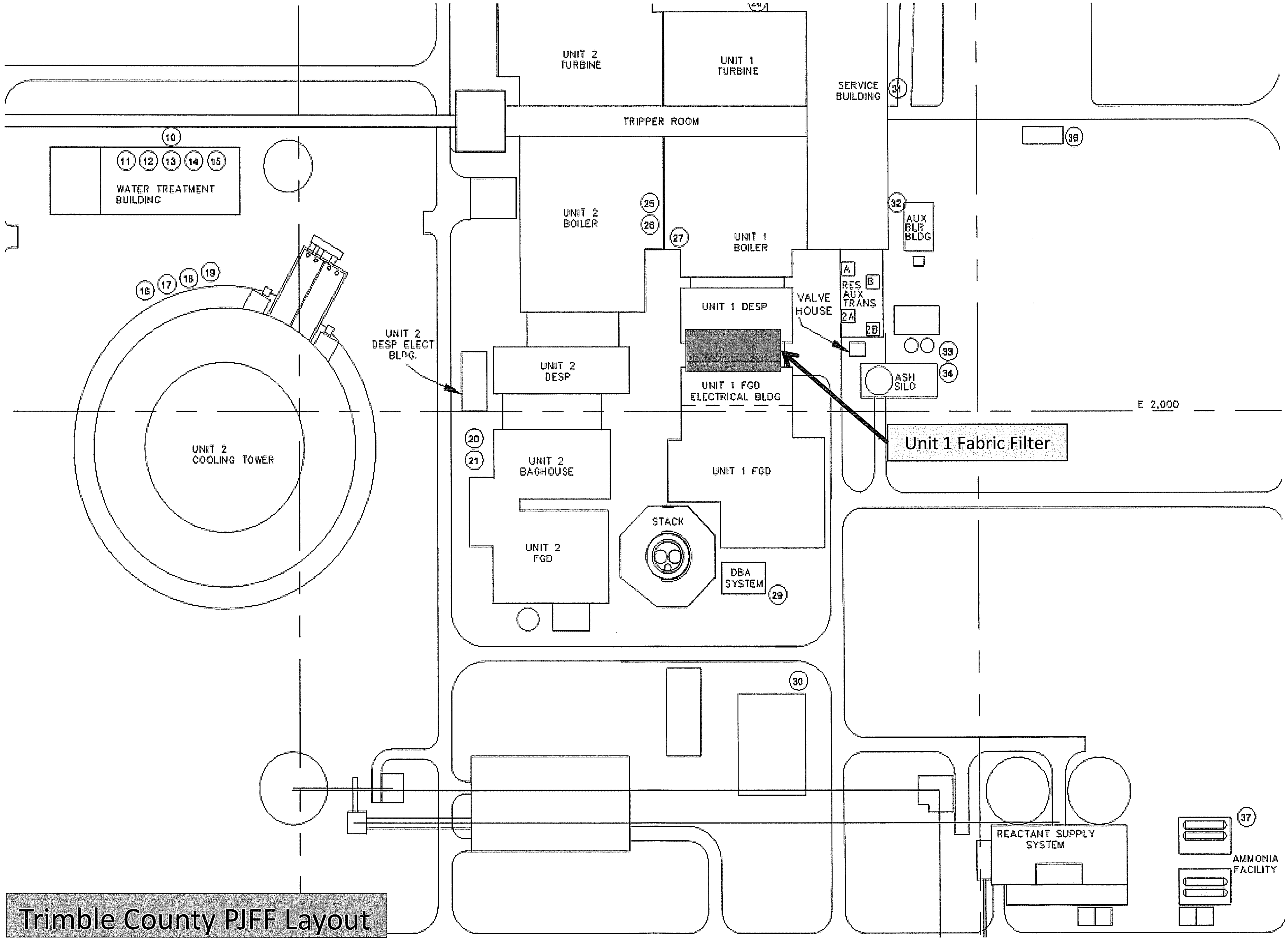
PPL companies





Mill Creek
Generating Station
OHIO
RIVER
McHarry Hill
Valley Station
Valley Gardens
Johnsontown
Prairie Village
Stonestreet
Meadow Lawn
Auburndale
Fairdale
Happy Hollow
Substation
Conveyor
Powerplant
CONTOUR INTERVAL 10 FEET
DOTTED LINES REPRESENT 5-FOOT CONTOURS
NATIONAL GEODETIC VERTICAL DATUM OF 1929
LG&E KU
PPL companies


Trimble County
Generating Station
OHIO
RIVER
BEDFORD
Marble Hill
Miles Point
Bethlehem
Wises Landing
Mt Pleasant
JEFFERSON CO
CLARK CO
CONTOUR INTERVAL 10 FEET
NATIONAL GEODETIC VERTICAL DATUM OF 1929
LG&E KU
PPL companies



Trimble County 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 T
General Index except CTAC and Special Charges, all Pilot Programs listed in Section 3 of the T
General Index, and the FAC and DSM Adjustment Clauses. 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, 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 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 LOUISVILLE GAS AND ELECTRIC COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	))))))	CASE NO. 2011-00162

DIRECT TESTIMONY OF
LONNIE E. BELLAR
VICE PRESIDENT, STATE REGULATION AND RATES
LOUISVILLE GAS AND ELECTRIC 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 of State Regulation and Rates for Louisville Gas and Electric Company ("LG&E"). I am employed by LG&E and KU Services Company, which provides services to 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. What is the purpose of your testimony?

A. My testimony provides an overview of our other witnesses' testimony and LG&E's 2011 Environmental Compliance Plan ("2011 Plan"), and outlines our request for Certificates of Public Convenience and Necessity ("CPCNs") for facilities contained in the 2011 Plan. I will also explain why LG&E 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 LG&E's last rate case. I will also address the plan to finance the proposed construction of these facilities at the Mill Creek Generating Station ("Mill Creek") and Trimble County Unit 1 ("TC1").

Overview of Testimony

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

A. In addition to my testimony, LG&E 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 LG&E'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 LG&E's 2011 Plan. Mr. Revlett describes the pertinent statutes, rules, or regulations requiring LG&E to take action.
- Charles R. Schram, Director, Energy Planning, Analysis and Forecasting, presents testimony on the cost-effectiveness of the projects in LG&E's 2011 Plan, and presents as an exhibit the cost-benefit study LG&E performed.
- Shannon L. Charnas, Director, Accounting and Regulatory Reporting, presents testimony affirming that the costs for which LG&E is seeking recovery through its Environmental Surcharge tariff are not included in base rates, and describes the accounting associated with the projects in LG&E's 2011 Plan, all consistent with the Commission's prior orders.

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

<u>**2011 Environmental Surcharge Plan and Recovery**</u>

Q. Please describe the 2011 Environmental Surcharge Plan LG&E proposes in this proceeding.

A. The projects in LG&E's 2011 Plan will serve Mill Creek and TC1. LG&E's 2011 Plan contains two new capital projects (along with their associated operating and maintenance ("O&M") expenses), and is attached as Exhibit JNV-1 to Mr. Voyles's testimony. Mr. Voyles's testimony presents LG&E's 2011 Plan, describes the need for the new projects in the plan, and provides the timeframe for construction of the projects. Mr. Revlett's testimony presents LG&E's evidence concerning the applicable environmental regulatory requirements and shows how the pollution control facilities in the 2011 Plan satisfy LG&E's environmental obligations. Mr. Schram's testimony provides evidence as to the cost effectiveness of the projects and details the estimated capital cost of $1.4 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 LG&E to comply with the federal Clean Air Act as amended ("CAAA"), the U.S. Environmental Protection Agency's ("EPA's") new 1-

hour sulfur dioxide ("SO_2") National Ambient Air Quality Standard ("NAAQS"), the proposed Clean Air Transport Rule ("CATR"), the proposed national emission standards for hazardous air pollutants ("HAPs Rule"), and other environmental requirements that apply to LG&E facilities used in the production of energy from coal.

Q. What are the components of Project 26, and why are they necessary?

A. First, Project 26 contains the construction of new Flue Gas Desulfurization ("FGD") equipment and upgrades to existing FGD equipment. More specifically, LG&E proposes to remove the current FGDs on Mill Creek Units 1, 2, and 3, build two new FGDs (one to serve Mill Creek Units 1 and 2, another to serve Mill Creek Unit 4), and tie Mill Creek Unit 3 into the existing (but upgraded) Mill Creek Unit 4 FGD. These new and upgraded facilities are necessary to comply with the proposed CATR's tighter restrictions on the emission of SO_2 and the 1-hour SO_2 NAAQS. Mr. Revlett's testimony provides a full discussion of this and all the applicable environmental regulations and rules that apply to LG&E's 2011 Plan.

Second, Project 26 includes modifications to various systems at Mill Creek Units 3 and 4 to expand the operating range of the units at which their Selective Catalytic Reduction ("SCR") equipment can function to reduce nitrogen compound ("NO_X") emissions. Project 26 also includes an upgrade to the Unit 4 SCR. The proposed generating unit modifications and SCR upgrade are required by the proposed CATR, which will impose stricter NO_X emissions requirements on LG&E and KU.

Third, Project 26 includes the addition of Particulate Matter Control Systems to serve each of the four Mill Creek 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"). These systems are necessary to meet the HAPs Rule's mercury and particulate emissions requirements.

The total projected capital cost of these facilities is $1,268 million: $331 million for Unit 1, $328 million for Unit 2, $223 million for Unit 3, and $386 million for Unit 4. The projected annual O&M cost of the non-FGD facilities (for which LG&E 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). LG&E will calculate the actual incremental annual O&M cost associated with the FGD facilities recovered through the environmental surcharge mechanism in the manner described in Mr. Conroy's testimony.

Also, the Commission approved SAM mitigation systems for Mill Creek Units 3 and 4 as part of LG&E's 2006 Plan (Project 19), though those systems have not yet been installed (though LG&E plans to install them in the near future). As Mr. Conroy explains in his testimony, LG&E proposes to report those systems' SAM-sorbent-O&M costs as part of this project's SAM-sorbent-O&M costs.

Q. What are the components of Project 27, and why are they necessary?

A. Project 27 has just one component, the addition of a Particulate Matter Control System to serve TC1. This system is necessary to meet the HAPs Rule's mercury and particulate emissions requirements.

The total projected capital cost of this facility is $124 million. The projected annual O&M cost of this facility at TC1 (for which LG&E 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 TC1 is incremental to the amount already being collected through the environmental surcharge mechanism for TC1's existing SAM mitigation system. The Commission approved the TC1 SAM mitigation system as part of LG&E's 2006 Plan (Project 19). As Mr. Conroy explains in his testimony, LG&E proposes to report TC1's existing SAM mitigation system's SAM-sorbent-O&M costs as part of this project's SAM-sorbent (baghouse lime) O&M costs.

Q. What evidence does LG&E present on the accounting of the cost for the 2011 Plan?

A. Ms. Charnas's testimony explains LG&E'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 LG&E's accounting for retirements and replacements associated with the 2011 Plan. Ms. Charnas further affirms that the environmental compliance costs LG&E 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 LG&E present concerning cost recovery and reporting under its ECR surcharge rider?

A. Mr. Conroy presents testimony to explain LG&E's changes to its monthly reporting requirements and affirming that the calculation of LG&E'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 LG&E proposes and explains why the revisions of the forms are appropriate.

Also, LG&E is proposing some minor clarifying changes to its Environmental Cost Recovery Surcharge tariff. LG&E 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 LG&E'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 CATR and HAPs Rule are not yet final, it is prudent and in the interest of LG&E's customers to begin acting now to achieve compliance. Moreover, the NAAQS are final and recent changes to them will soon be enforceable.

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 LG&E'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, LG&E 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 Clear Air Act as amended.

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

A. The projects in the 2011 Plan reaffirm and strengthen LG&E's long-standing commitment to the efficient, safe, and environmentally responsible use of coal as a fuel source in its generating facilities. LG&E'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, LG&E and KU 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 LG&E currently authorized in its ECR tariff?

A. LG&E 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. 2009-00198 and the Commission's July 30, 2010 Order in Case No. 2009-00549.

Q. What ROE is LG&E requesting in this proceeding?

A. The Company is requesting continuation of the 10.63 percent ROE. In LG&E'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 LG&E's monthly environmental surcharge filings.[1] 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.[2] 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 LG&E propose to recover the cost of the pollution control projects in its 2011 Plan?

A. LG&E proposes to recover the cost of the pollution control projects in its 2011 Plan through LG&E's Electric 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 LG&E's proposed changes in the terms of Electric Rate Schedule ECR and affirms that the calculation will be consistent with the methods and methodologies previously approved by the Commission. Also, Mr. Conroy's testimony discusses changes to LG&E's monthly ECR filing forms.

Q. What revenue allocation is LG&E proposing in this case?

A. LG&E is proposing to use total revenues (including base rate, fuel adjustment clause, and demand-side management revenues) to allocate the environmental surcharge

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[1] *In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of Electric and Gas Base Rates* (Case No. 2009-00549), Stipulation, June 8, 2010 at 4.
[2] *Id.* at Final Order, July 30, 2010 at p. 11, 37.

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. 2009-00549, given the importance of industrial customers to Kentucky's economy (i.e., providing jobs and tax revenues), and given the amount of LG&E's proposed investment in ECR facilities compared to LG&E's current electric rate base, revenue allocations that balance the interests of all customers may merit consideration.

Certificates of Public Convenience and Necessity

Q. Is LG&E requesting CPCNs in this proceeding?

A. Yes. LG&E is seeking eight CPCNs: one to remove the current Mill Creek Units 1 and 2 FGDs and to build a new FGD to serve both units; one to remove the current Mill Creek Unit 3 FGD and to tie-in Unit 3 to the existing Mill Creek Unit 4 FGD (which will be upgraded); one to build a new FGD to serve Mill Creek Unit 4; and one for each of the Particulate Matter Control Systems LG&E proposes to build to serve the four Mill Creek units and TC1.

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, all of the proposed FGD work is required to meet the requirements of EPA's CATR and the new 1-hour SO_2 NAAQS. Also, each of the proposed Particulate Matter Control Systems is necessary to comply with EPA's HAPs Rule. As Messrs. Voyles and Revlett further describe, the HAPs Rule's requirements will, barring an unprecedented presidential intervention, be binding on LG&E 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, LG&E could not operate the Mill Creek units or TC1 under the HAPs Rule, nor could LG&E operate the Mill Creek units under CATR and the 1-hour SO_2 NAAQS without the proposed FGD construction. The continued service of these units for LG&E'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 adequate (in the case of the Mill Creek FGDs) or comparable facilities exist at Mill Creek or TC1—nor will it unnecessarily encumber the landscape because the facilities will be physically adjacent to existing generating-unit-related facilities on the Mill Creek and Trimble County 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 LG&E 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 LG&E plan to finance construction of the FGDs and Particulate Matter Control Systems?

A. LG&E 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 LG&E 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 LG&E need to begin preparing for construction of the FGDs and 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. LG&E 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. LG&E appreciates the importance of this statute and has adhered to it with regard to the FGDs and Particulate Matter Control Systems. Although LG&E 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. LG&E 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 LG&E 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 LG&E have reasonably filed this Application sooner?

A. No, LG&E 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 LG&E has moved with all reasonable and deliberate speed to file with the Commission an Application that contains proposals that will ensure LG&E's compliance with the proposed rules. Moreover, by filing now, LG&E 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. 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 must 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, my recommendation is that the Commission grant LG&E its requested CPCNs to perform the FGD construction and upgrade work at Mill Creek and Particulate Matter Control System construction at Mill Creek and TC1 that I have described. I further recommend that the Commission approve LG&E's 2011 Plan and application for cost recovery of its compliance costs through the Electric 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 Louisville Gas and Electric 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 Energy LLC	
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 LOUISVILLE GAS AND ELECTRIC COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	))))))	CASE NO. 2011-00162

DIRECT TESTIMONY OF JOHN N. VOYLES, JR. VICE PRESIDENT, TRANSMISSION AND GENERATION SERVICES LOUISVILLE GAS AND ELECTRIC 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 Louisville Gas and Electric Company ("LG&E"), and I am an employee of LG&E and KU Services Company, which provides services to 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 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?

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[1] Case Nos. 2009-00197 (KU 2009 ECR Plan), and 2009-00198 (LG&E 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.*

A. Yes. I am sponsoring the following exhibits:

Exhibit JNV-1	Louisville Gas and Electric 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 (LG&E)

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the proposed pollution control projects contained in LG&E'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 LG&E is seeking environmental surcharge recovery. These projects are required for LG&E to comply with the federal Clean Air Act as amended ("CAAA"), the new National Ambient Air Quality Standard ("NAAQS"), the proposed Clean Air Transport Rule ("CATR"), the proposed national emission standards for hazardous air pollutants ("HAPs Rule"), and other environmental requirements that apply to LG&E facilities used in the production of energy from coal.

I will also be supporting LG&E's request for Certificates of Public Convenience and Necessity ("CPCNs") related to the proposed 2011 Plan projects 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 LG&E's 2011 Environmental Compliance Plan.

A. The two projects contained on Page 1 of Exhibit JNV-1 and identified as LG&E Projects 26 and 27 are required in order for LG&E to comply with the CAAA, NAAQS, CATR, the HAPs Rule, and other environmental requirements applicable to LG&E power plants. Project 26 will also be necessary to comply with the new 1-hour SO_2 NAAQS, as Gary H. Revlett explains in his testimony. The total capital cost of the new and additional projects in the 2011 Plan is estimated to be approximately $1.4 billion. LG&E is also seeking recovery of operating and maintenance expenses associated with Projects 26 and 27, as detailed on Page 2 of Exhibit JNV-1.

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

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

Column 1 assigns a number to the project for identification purposes in sequence with the projects from Case No. 94-332 (1 through 5),[3] Case No. 2000-386 (6),[4] Case No. 2002-00147 (7 through 10),[5] Case No. 2004-00421 (11

[3] *In the Matter of: The Application of Louisville Gas and Electric Company for Approval of a 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.*

[4] *In the Matter of: The Application of Louisville Gas and Electric 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 Louisville Gas and Electric Company for Approval of Its 2002 Compliance Plan for Recovery by Environmental Surcharge.*

through 17),[6] Case No. 2006-00208 (18 through 21),[7] and Case No. 2009-00198 (22 through 25).[8]

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

Column 3 identifies the pollution control facility that LG&E 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 LG&E to act on the associated project.

Column 6 identifies the environmental permits required for LG&E'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. 94-332 (1 through 5),[9] Case No. 2000-386 (6),[10] Case No. 2002-00147 (7 through 10),[11] Case No. 2004-00421

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[6] *In the Matter of: The Application of Louisville Gas and Electric Company for Approval of Its 2004 Compliance Plan for Recovery by Environmental Surcharge.*

[7] *In the Matter of: The Application of Louisville Gas and Electric Company for Approval of Its 2006 Compliance Plan for Recovery by Environmental Surcharge.*

[8] *In the Matter of: The Application of Louisville Gas and Electric Company for a Certificate 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 Louisville Gas and Electric Company for Approval of a 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.*

[10] *In the Matter of: The Application of Louisville Gas and Electric 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 Louisville Gas and Electric Company for Approval of Its 2002 Compliance Plan for Recovery by Environmental Surcharge.*

(11 through 17),[12] Case No. 2006-00208 (18 through 21),[13] and Case No. 2009-00198 (22 through 25).[14]

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

Column 3 identifies the pollution control facility that LG&E 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).

LG&E Air Compliance Projects

Q. How did LG&E 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 LG&E'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

[12] *In the Matter of: The Application of Louisville Gas and Electric Company for Approval of Its 2004 Compliance Plan for Recovery by Environmental Surcharge.*

[13] *In the Matter of: The Application of Louisville Gas and Electric Company for Approval of Its 2006 Compliance Plan for Recovery by Environmental Surcharge.*

[14] *In the Matter of: The Application of Louisville Gas and Electric Company for a Certificate of Public Convenience and Necessity and Approval of Its 2009 Compliance Plan for Recovery by Environmental Surcharge.*

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. (Charles R. Schram's testimony and its attachments contain the full details of that analysis.)

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

Project 26: Mill Creek Station Air Compliance

Q. What are the components of Project 26, and why are they necessary?

A. First, Project 26 contains the construction of new Flue Gas Desulfurization ("FGD") equipment and upgrades to some existing FGD equipment. More specifically, LG&E proposes to build two new FGDs (one to serve both Mill Creek Units 1 and 2, another to serve Mill Creek Unit 4), to tie Mill Creek Unit 3 into the existing (but upgraded) Mill Creek Unit 4 FGD, and then to remove the current FGDs on Mill Creek Units 1, 2, and 3. These new and upgraded facilities are necessary to comply with the 1-hour SO_2 NAAQS, under which Jefferson County is expected to be declared a non-attainment area and would require SO_2 emission reductions at Mill Creek. These projects also support compliance with the proposed reductions on the emission of SO_2

from the CATR. (Mr. Revlett's testimony provides a full discussion of this and all the applicable environmental regulations and rules that apply to LG&E's 2011 Plan.)

Second, Project 26 includes modifications to various systems at Mill Creek Units 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 ("NO_X") emissions. Currently, the SCRs can operate only when the Mill Creek 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. Project 26 also includes an upgrade to the Unit 4 SCR to enhance its NO_X removal efficiency through the installation of additional ammonia injection points and static mixing vanes within the flue gas ductwork prior to the SCR determined by flue gas flow modeling of the unit. Although this SCR performs very well against industry standards, it is not performing as efficiently as other SCRs in the fleet. The proposed modifications 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.

Third, Project 26 includes the addition of Particulate Matter Control Systems to serve each of the four Mill Creek 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 baghouse 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 LG&E's 2006 Plan).[15] As Mr. Revlett's testimony describes, these systems are necessary to meet the mercury and particulate emissions reduction requirements contained in the proposed HAPs Rule.

The Commission approved SAM mitigation systems for Mill Creek Units 3 and 4 as part of LG&E's 2006 Plan (Project 19), though those systems have not yet been installed (though LG&E plans to install them in the near future). As Robert M. Conroy explains in his testimony, LG&E proposes to report the lime injection systems' and the previously approved SAM mitigation systems' sorbent O&M costs as part of Project 26's SAM-sorbent-O&M costs. One reason for that approach is that, as a practical matter, LG&E 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 subaccount, making it very difficult to determine how much SAM sorbent cost should be reported with reasonable certainty 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 Mill Creek generating unit.

[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).

Project 27: Trimble County Unit 1 Air Compliance

Q. What are the components of Project 27, and why are they necessary?

A. Project 27 consists of adding a Particulate Matter Control System to Trimble County Unit 1 ("TC1"), including installing supporting ash transport system upgrades. Like the Particulate Matter Control Systems for Mill Creek, the TC1 Particulate Matter Control System will be similar to the comparable equipment installed and operating at TC2. The proposed Particulate Matter Control System is necessary to meet the mercury and particulate emissions reduction requirements contained in the proposed HAPs Rule.

The Commission approved the existing TC1 SAM mitigation system as part of LG&E's 2006 Plan (Project 19). As Mr. Conroy explains in his testimony and for the same reasons given above concerning tracking SAM-sorbent-O&M costs at Mill Creek, LG&E proposes to report the existing TC1 SAM mitigation system's sorbent O&M costs as part of Project 27's SAM-sorbent-O&M.

Exhibit JNV-3 contains a line-drawing schematic diagram of the existing and proposed components of the entire flue-gas stream for TC1.

Q. Do the air quality systems for Projects 26 and 27 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 26 and 27 as they apply to specific generating units at the Mill Creek or Trimble County generation stations.

Project 26 Component: Removing the Mill Creek Units 1 and 2 FGDs and Building a New FGD to Serve Both Units

Q. Please describe the proposed removal of the Mill Creek Units 1 and 2 FGDs and construction of a new FGD to serve both units.

A. LG&E proposes to build a single new FGD to serve both units and then to remove the existing Mill Creek Units 1 and 2 FGDs. The new FGD design is consistent with the FGDs installed on Ghent Generating Station Units 1, 3, and 4 as well as the combined FGD for E.W. Brown Station Units 1, 2 and 3. The basic design of an FGD like the ones LG&E proposes to install is shown in Figure 1 below.

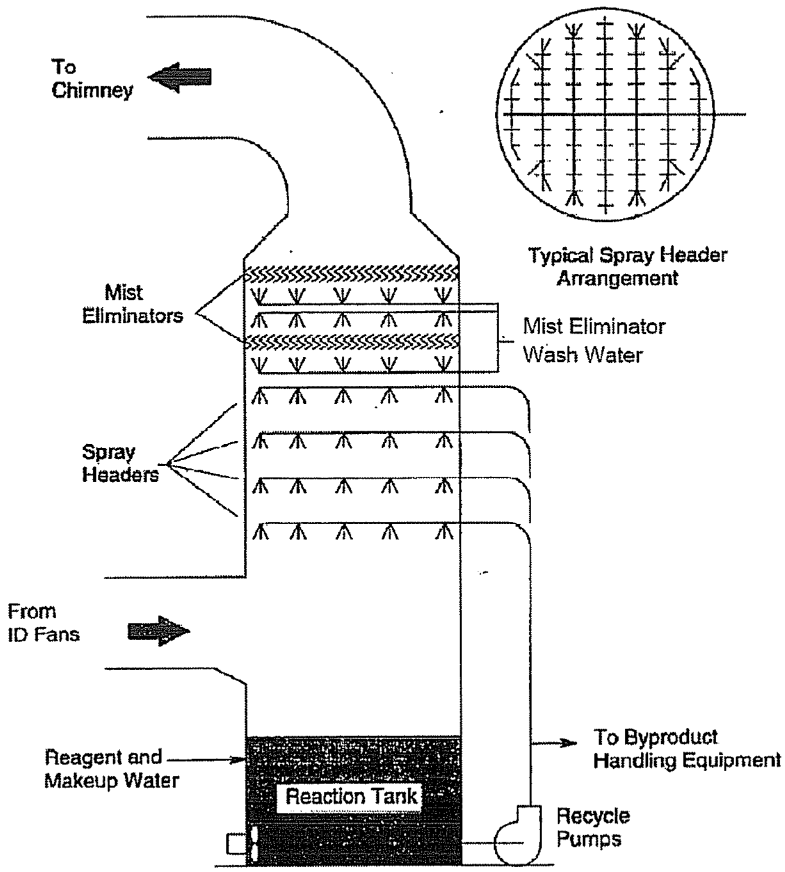


Figure 1: Wet FGD Spray Tower Process

Constructing a new FGD is a more cost-effective option than redesigning and modifying the existing, first-generation FGDs to increase the SO_2 removal from their current approximately 90 percent removal to the 98+ percent SO_2 removal that today's technology can achieve. To gain the necessary increased efficiency from the existing FGDs, multiple, extended outages would be required to accommodate the necessary structural and infrastructure replacement and upgrades from the original designs. Long outages (of multiple months) would likely require replacement power to meet loads at peak times that is typically less economical than running the Mill Creek units. The new combined FGD will be designed to remove 98+ percent of the SO_2 emissions from both units. Wet FGD is the best available control technology currently available for SO_2 reduction from the Mill Creek units which utilize high sulfur coals. The new FGD's SO_2 scrubbing capabilities (compared to the units' current FGDs) will increase the amount of limestone required and byproduct produced proportionally to the additional capture of SO_2. Also, the planned FGD will be able to comply consistently with the HAPs Rule's HCl emissions limitations (measuring SO_2 as a proxy for HCl, as allowed by the HAPs Rule).

The new FGD installation requires locating the FGD and associated equipment away from the existing FGD locations. This allows construction to be performed while the units remain in operation and then, when the construction is completed, the units can be tied in to the new technologies during shorter outages. The new FGD location will include a new chimney similar to those installed on the FGD projects recently completed at Ghent and Brown. The addition of a higher-efficiency FGD in combination with the installation of Particulate Matter Control Systems will require the installation of larger induced draft fans and/or the installation of booster fans to account for the increased pressure drop through the flue gas train. These larger or additional fans will likely require auxiliary power upgrades.

LG&E proposes to begin initial demolition activities related to the construction (e.g., demolition of existing warehouses and craft locker rooms northeast of Units 1 and 2) in the fall of 2011 and to begin constructing the new FGD in early 2012 with the work completed and the system placed into operation by mid-2015. Once the new FGD to service both Units 1 and 2 is placed into operation, the existing Mill Creek Units 1 and 2 FGDs will be demolished. The project includes reconstruction of the warehouse space and craft locker rooms in a different location at the site.

The total projected capital cost of this portion of Project 26 is $354 million. LG&E will calculate the annual O&M cost associated with the new FGD (for which LG&E is seeking recovery through its environmental surcharge mechanism) in the manner described in Mr. Conroy's testimony.

<u>Project 26 Component: New FGD for Mill Creek Unit 4</u>

Q. Please describe the proposed new Mill Creek Unit 4 FGD.

A. LG&E proposes to install a new FGD for Unit 4 that can consistently achieve SO_2 emissions reductions greater than 98 percent. Wet FGD is the best available control technology currently available for SO_2 reduction for units burning high-sulfur coals. The new FGD's SO_2 scrubbing capabilities (compared to its current FGD) will increase the amount of limestone required and byproduct produced proportionally to the additional capture of SO_2. Also, as with the new combined Units 1 and 2 FGD, Unit 4's planned FGD will be able to comply with the HAPs Rule's HCl emissions limitations (measuring SO_2 as a proxy for HCl, as allowed by the HAPs Rule).

The new FGD and associated equipment will be installed away from the existing unit 4 FGD equipment. This allows construction to be performed while the units remain in operation and then, when construction is completed, Unit 4 can be tied in to the new technology during a shorter outage. The new FGD location will include a new chimney for Unit 4 (Mill Creek Unit 3 will utilize the existing Unit 4 chimney) similar to those installed on the FGD projects recently completed at Ghent and Brown. The addition of the higher-efficiency FGD in combination with the installation of a Particulate Matter Control System will require the installation of larger induced draft fans and/or the installation of booster fans to account for the increased pressure drop through the flue gas train. These larger or additional fans will likely require auxiliary power upgrades.

LG&E proposes to begin initial demolition activities related to the construction in the fall of 2011, and to begin building Unit 4's new FGD in the first half 2012 with the Unit 4 tie in occurring in late 2014.

The total projected capital cost of this portion of Project 26 is \$218 million. LG&E will calculate the annual O&M cost associated with the new Unit 4 FGD (for which LG&E is seeking recovery through its environmental surcharge mechanism) in the manner described in Mr. Conroy's testimony.

<u>Project 26 Component: Removal of Current Mill Creek Unit 3 FGD, and Unit 3 Tie-In to Current Unit 4 FGD</u>

Q. **Please describe the proposed removal of the current Mill Creek Unit 3 FGD and tying-in of Unit 3 to the existing Unit 4 FGD.**

A. Once the new Mill Creek Unit 4 FGD is in service, LG&E proposes to upgrade Unit 4's existing FGD system to accommodate Unit 3 so it can consistently achieve SO_2

emissions of 98 percent on a continuous basis when burning high-sulfur coals. The existing Unit 4 FGD is approximately 20% larger in size than the existing Unit 3 FGD (due to generating capacity differences between Units 3 and 4) and can accommodate the needed efficiency upgrades, whereas the existing Unit 3 FGD cannot be modified for the increased capacity due to physical structural steel constraints and FGD module size limitations. Therefore, upgrading the existing Unit 4 FGD with modified spray levels and/or flue gas contact rings/trays and flue gas flow modifications is the most feasible and economical control technology considered for SO_2 reduction for Unit 3. The additional scrubbing capabilities will increase the amount of limestone required and byproduct produced proportionally to the increase in SO_2 removal. The upgraded FGD for Unit 3 will be able to comply consistently with the HAPs Rule's HCl emissions limitations (measuring SO_2 as a proxy for HCl, as allowed by the HAPs Rule).

Tying in Unit 3 to Unit 4's existing FGD will result in Unit 3's using the existing Unit 4 chimney. Unit 3's current chimney will be capped and remain in place similar to that done to Ghent Units 1 and 4 on the recent FGD installations. Once the tie-in to the upgraded FGD is completed, Unit 3's current FGD modules, which will no longer be needed, will be demolished similar to that of Units 1 and 2.

Refurbishment work on the existing Unit 4 FGD will occur after tying Unit 4 into the new FGD. LG&E plans to place Unit 4 back into service in late 2014, with Unit 3 being placed back into service (after being tied into the refurbished former Unit 4 FGD) in late 2015.

The total projected capital cost of this portion of Project 26 is $73 million. LG&E will calculate the annual O&M cost associated with the newly tied-in FGD for

Unit 3 (for which LG&E is seeking recovery through its environmental surcharge mechanism) in the manner described in Mr. Conroy's testimony.

<u>Project 26 Component: Mill Creek Unit 4 SCR Upgrade and Modifications at Mill Creek Units 3 and 4 to Expand Operating Range at which SCRs Can Function</u>

Q. Please describe the proposed upgrade to Unit 4's SCR.

A. As stated above, Unit 4's SCR, although it compares favorably to other industry SCRs, performs slightly less well than the SCRs installed in the same era on Ghent Units 1, 3 and 4, Mill Creek Unit 3, and TC1. Modeling of the flue gas and ammonia mixing will take place to determine where additional mixing vanes (and possibly additional ammonia injection ports) can be installed to improve the ammonia mixing prior to entering the SCR. This modification will thus result in a higher NO_X removal ability of the SCR through better mixing and utilization of ammonia. The additional ammonia injection ports and static mixing vanes will likely be installed in close proximity to the current configuration between the boiler flue gas exit and the SCR inlet. The relative location of the proposed upgrade work is shown in Figure 2 below "Additional Ammonia Injection Points and Static Mixers."

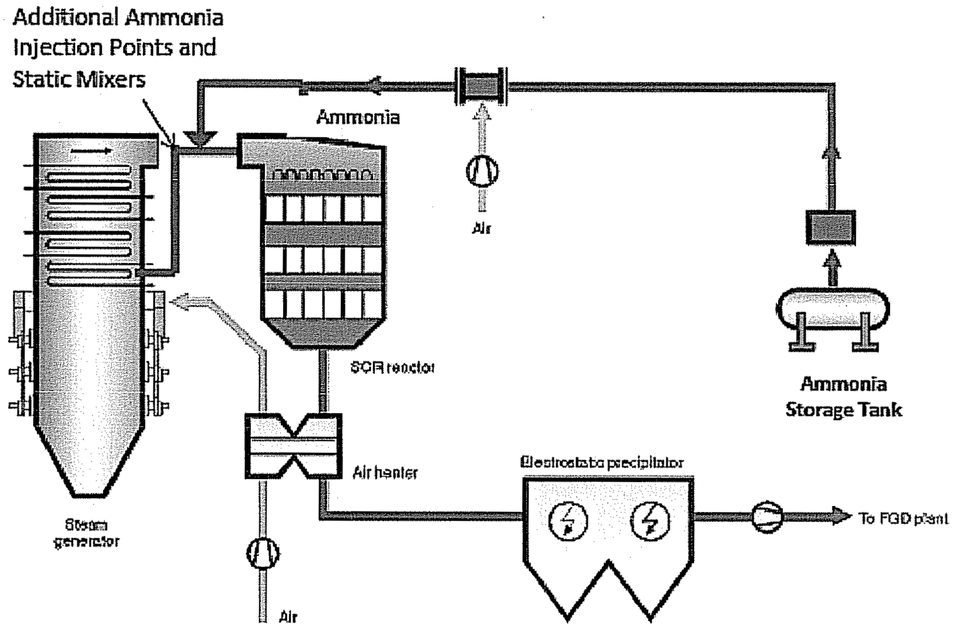


Figure 2: Location of Mill Creek Unit 4 SCR Upgrade Work

LG&E proposes to begin upgrading the Unit 4 SCR in late 2011, and the work should be complete by mid-2012.

The total projected capital cost of this portion of Project 26 is $6 million. There is no additional O&M cost associated with the upgrade.

Q. Please describe the proposed modifications at Mill Creek Units 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. LG&E proposes to make a variety of modifications and adjustments at Mill Creek Units 3 and 4 to expand the operating range at which the SCRs can function. Currently, the SCRs can operate only when the Mill Creek 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 running at lower load levels than those at which it is currently possible to operate 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 NO_X 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 beds 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, 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 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 LG&E'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 Mill Creek Units 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.

LG&E proposes to begin engineering work on Unit 3 in 2011, and the modifications should be complete by mid-2013. LG&E proposes to begin engineering work on Unit 4 in 2011 also, and the modifications should be complete by late 2014.

The total projected capital cost of this portion of Project 26 is $14 million: $7 million for Unit 3, and $7 million for Unit 4. There is no additional O&M cost associated with these modifications.

<u>Project 26 Component: Mill Creek Particulate Matter Control Systems, and</u>
<u>Project 27: Trimble County Unit 1 Particulate Matter Control System</u>

Q. Please describe the proposed Particulate Matter Control Systems for the Mill Creek units and Trimble County Unit 1.

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. LG&E proposes to install Particulate Matter Control Systems to serve all its Mill Creek units and TC1. The diagram in Figure 3 below illustrates the 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.)

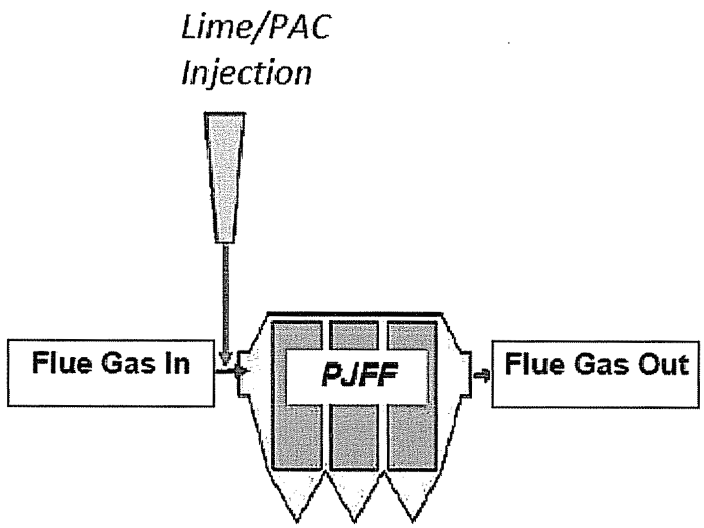


Figure 3: Particulate Matter Control Basic System Diagram

The first component of a Particulate Matter Control System is particulate-matter filtration via a fabric-filter baghouse. Baghouses like the ones LG&E proposes to install at Mill Creek and TC1 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 expected to be required by the regulations. Figure 4 below is an illustration of a typical baghouse.

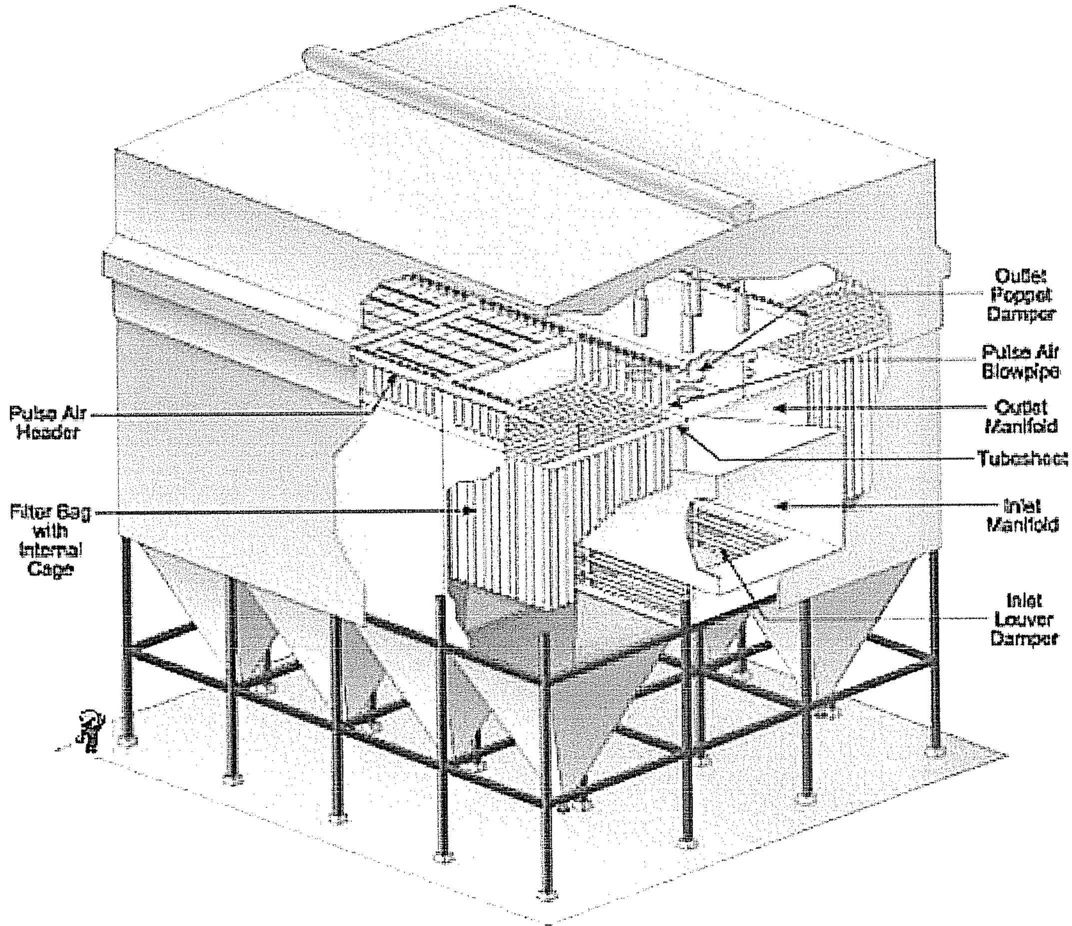


Figure 4: Illustration of a Typical Baghouse

Each 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 the Particulate Matter Control System is lime injection systems. 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.[16]

Q. Please describe the proposed construction schedules, capital costs, and operation and maintenance costs for the Particulate Matter Control Systems for the Mill Creek units and TC1.

A. LG&E proposes to begin installing the Particulate Matter Control Systems to serve all the Mill Creek units in early 2012, and the work should be complete by mid-2015 for Units 1 and 2, late 2015 for Unit 3, and late 2014 for Unit 4. For TC1, LG&E proposes to begin installing the Particulate Matter Control System in mid 2013, and the work should be complete by late 2015.

The total projected capital cost of these facilities at Mill Creek (part of Project 26) is $604 million: $155 million for Unit 1, $151 million for Unit 2, $143 million for Unit 3, and $155 million for Unit 4. The projected annual O&M costs of these facilities at Mill Creek are shown on page 2 of Exhibit JNV-1.

[16] 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.

For TC1, the total projected capital cost of these facilities (Project 27) is $124 million. The projected annual O&M costs of these facilities at TC1 are shown on page 2 of Exhibit JNV-1. The baghouse lime O&M amount for TC1 is incremental to the existing amount already being collected through the environmental surcharge mechanism for TC1's existing SAM mitigation system. As I mentioned above, Mr. Conroy's testimony explains that LG&E proposes to report the O&M costs of TC1's existing SAM mitigation system as part of Project 27's SAM-sorbent (baghouse lime) O&M costs.

Certificates of Public Convenience and Necessity

Q. Is LG&E seeking CPCNs for any of the facilities in its 2011 Plan?

A. Yes. LG&E is seeking eight CPCNs: one to remove the current Mill Creek Units 1 and 2 FGDs and to build a new FGD to serve both units; one to remove the current Mill Creek Unit 3 FGD and to tie-in Unit 3 to the existing Mill Creek Unit 4 FGD (which will be upgraded); one to build a new FGD to serve Mill Creek Unit 4; and one for each of the Particulate Matter Control Systems LG&E proposes to build to serve the four Mill Creek units and TC1. The testimony of Lonnie E. Bellar discusses in detail LG&E's request for CPCNs.

LG&E Must Begin Acting Now to Comply with NAAQS, CATR and the HAPs Rule

Q. Why does LG&E 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 NAAQS for SO_2 and NO_X are final, 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 LG&E 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 LG&E 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 LG&E'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, LG&E 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, LG&E 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, LG&E 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 LG&E'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 NAAQS, CATR and the HAPs Rule, what is LG&E's contracting and construction strategy to ensure timely construction of the needed facilities?

A. LG&E has hired an outside engineering firm to assist in the development of specifications for the needed facilities. LG&E plans to begin this month with the request-for-quotations ("RFQ") process for the required equipment purchases with a focus on the wet FGD, baghouse and fan technologies. After conducting the RFQ processes, LG&E plans to approve the needed purchases during the 4^{th} quarter of 2011 so that LG&E can assure equipment manufacturing space and delivery schedules are available from the necessary equipment suppliers. The contracts into which LG&E 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. (LG&E 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 LG&E 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 LG&E's proposed 2011 Plan, cost recovery for the plan through LG&E's environmental surcharge mechanism, and the requested CPCNs. These facilities are necessary to comply with NAAQS, CATR, and the HAPs Rule, and the construction timelines for these facilities necessitate that LG&E 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 Louisville Gas and Electric 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

LOUISVILLE GAS AND ELECTRIC COMPANY
2011 ENVIRONMENTAL COMPLIANCE PLAN

Project	Air Pollutant or Waste/By-Product To Be Controlled	Control Facility	Generating Station	Environmental Regulation*	Environmental Permit*	Actual or Scheduled Completion	Actual (A) or Estimated (E) Projected Capital Cost ($Million)
26	SO_2, SO_3, NO_x, Hg and Particulate	Flue Gas Desulfurization, Baghouse with Powdered Activated Carbon Injection, SCR Turn-Down (Unit 3 & 4), and SCR upgrade (Unit 4), Sulfuric Acid Mist Mitigation	Mill Creek Unit 1	Clean Air Act (1990), NAAQS, HAPS and CATR	Title V Permit	2015	$331.41 (E)
			Mill Creek Unit 2			2015	$328.02 (E)
			Mill Creek Unit 3			2015	$223.06 (E)
			Mill Creek Unit 4			2012-2014	$385.73 (E)
27	NO_x, Hg and Particulate	Baghouse with Powdered Activated Carbon Injection	Trimble County Unit 1	Clean Air Act (1990), HAPS and CATR	Title V Permit	2012	$123.75 (E)
							$1,391.97

* Sponsored by Witness Revlett

LOUISVILLE GAS AND ELECTRIC 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
26	SO_2, SO_3, NO_x, Hg and Particulate	Flue Gas Desulfurization, Baghouse with Powdered Activated Carbon Injection, SCR Turn-down (Unit 3 & 4), and SCR upgrade (Unit 4), Sulfuric Acid Mist Mitigation	Mill Creek Unit 1	$ -	$ -	$ -	$ 5,044,845	$ 8,806,961	$ 9,022,738	$ 9,242,832	$ 9,467,327	$ 9,696,312
			Mill Creek Unit 2	$ -	$ -	$ -	$ 6,454,427	$ 9,695,385	$ 9,920,850	$ 10,150,825	$ 10,385,398	$ 10,624,664
			Mill Creek Unit 3	$ -	$ 1,693,407	$ 3,447,748	$ 4,857,328	$ 13,019,344	$ 13,333,943	$ 13,654,833	$ 13,982,142	$ 14,315,996
			Mill Creek Unit 4	$ -	$ -	$ 3,631,737	$ 15,519,305	$ 15,881,381	$ 16,250,699	$ 16,627,402	$ 17,011,640	$ 17,403,563
27	NO_x, Hg and Particulate	Baghouse with Powdered Activated Carbon Injection	Trimble County Unit 1	$ -	$ -	$ -	$ 3,732,365	$ 7,614,024	$ 7,766,305	$ 7,921,631	$ 8,080,064	$ 8,241,665

Exhibit JNV-2

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

LG&E® KU®

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

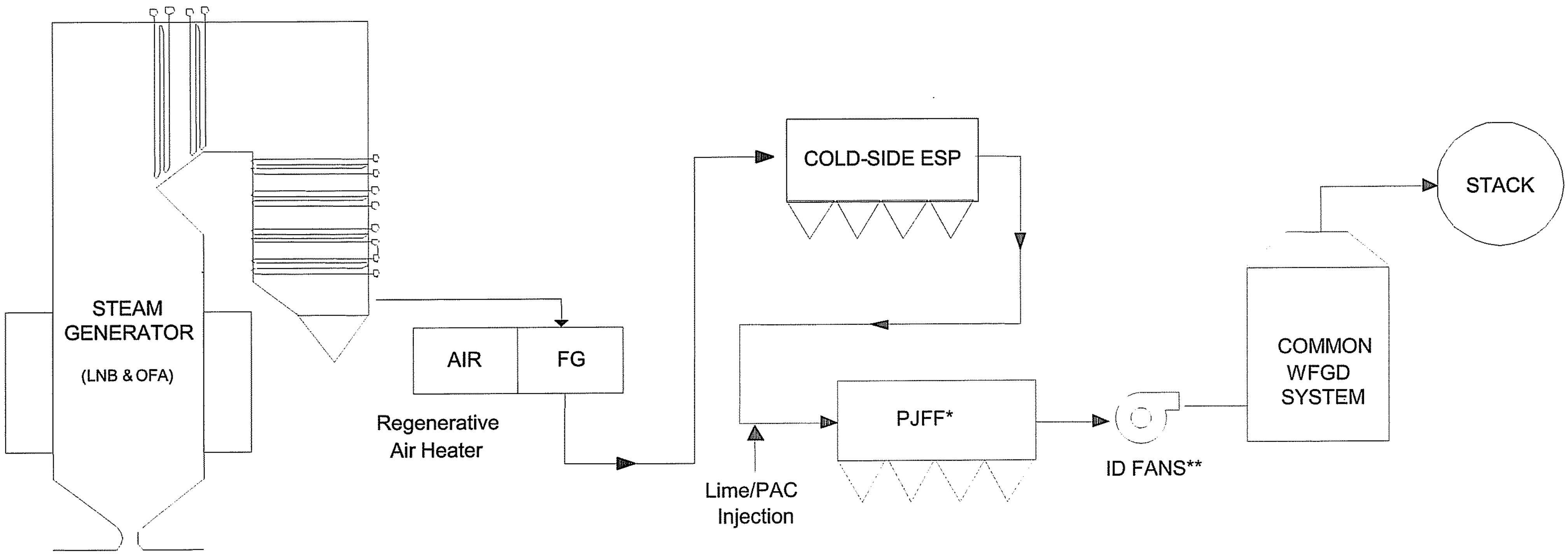
For Mill Creek Generating Station and Trimble County Unit 1

LG&E KU

PPL companies

May 2011

Mill Creek Unit 1 and 2
AQC Process Flow Diagram

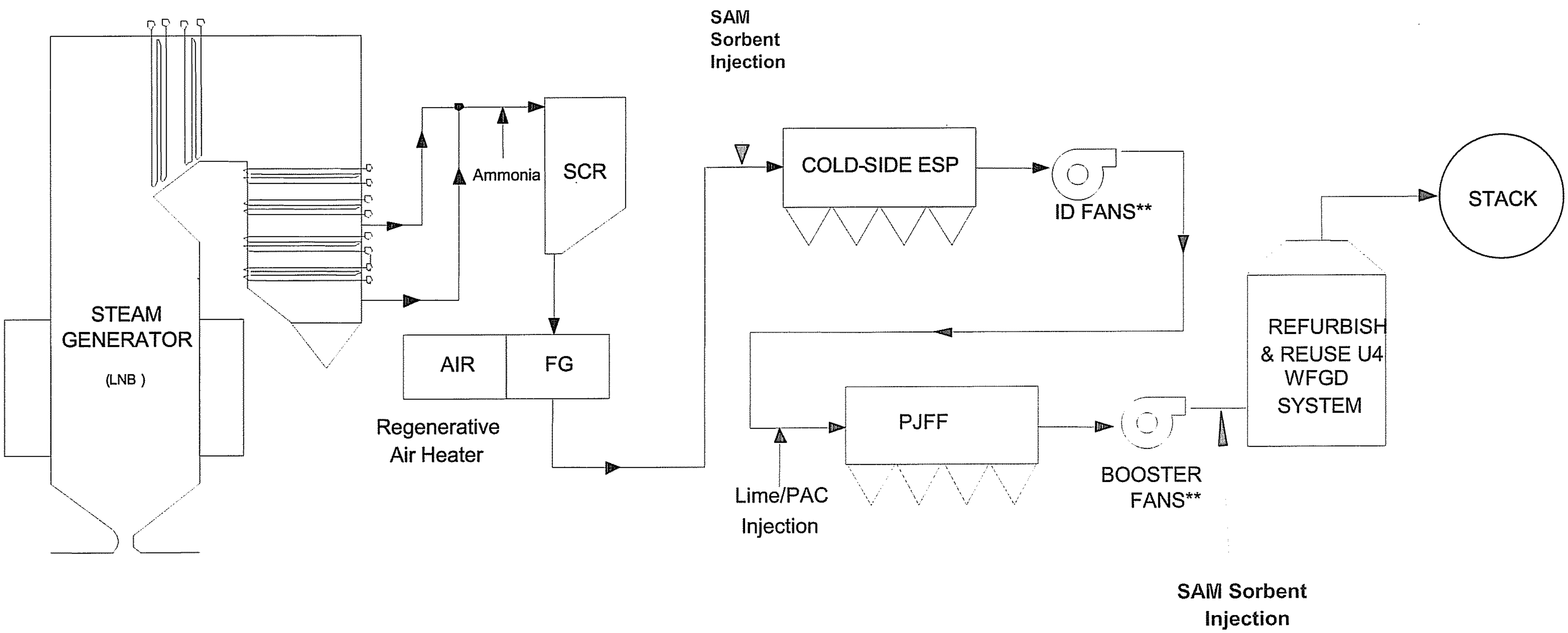


***Replacement to new Booster Fans or larger ID Fans is yet to be determined*

Black = Existing
Red = Preliminary Additions

May-11

Mill Creek Unit 3
AQC Process Flow Diagram

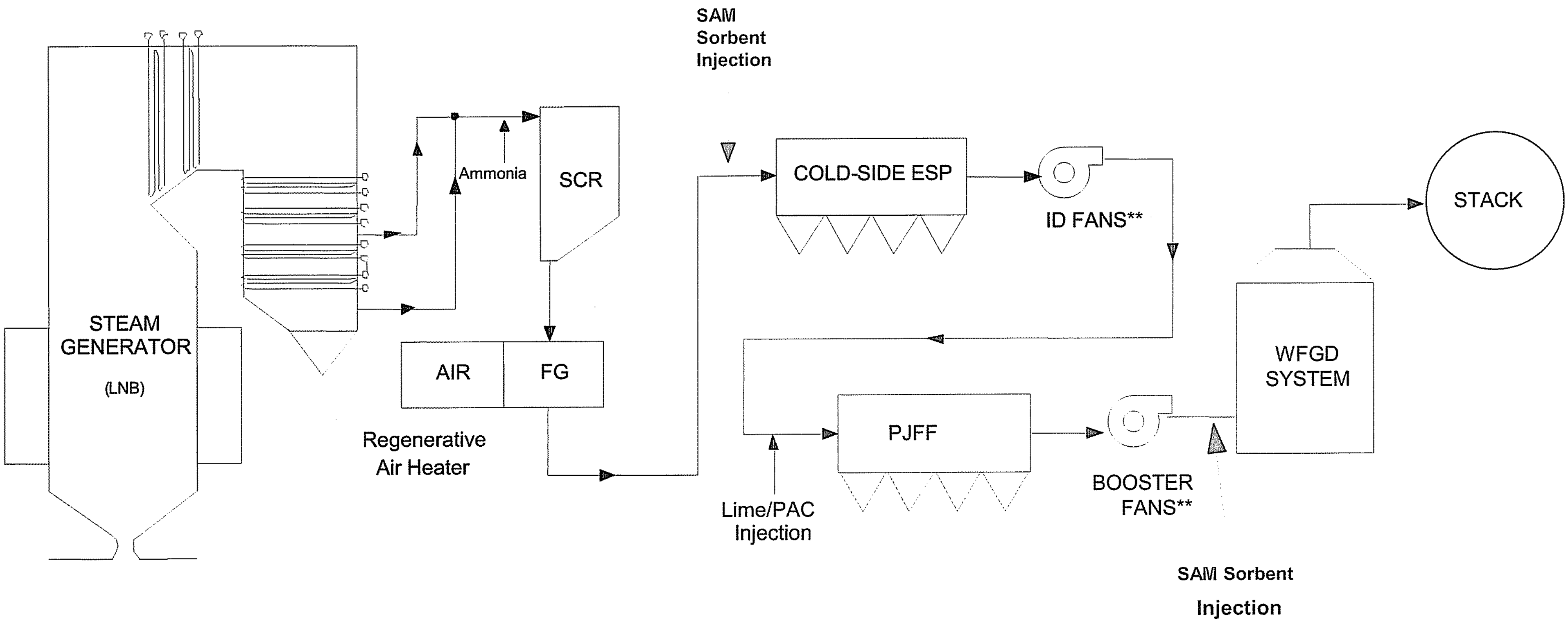


***Replacement to new Booster Fans or larger ID Fans is yet to be determined*

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

May-11

Mill Creek Unit 4
AQC Process Flow Diagram

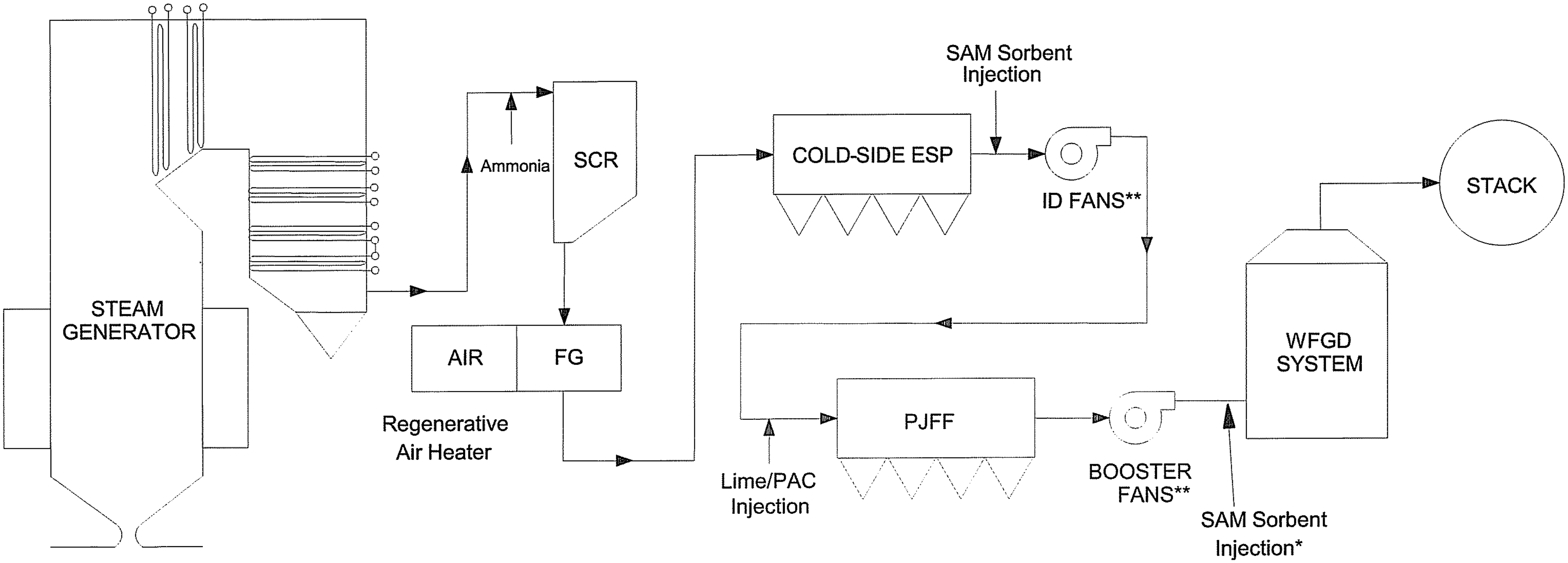


***Replacement to new Booster Fans or larger ID Fans is yet to be determined*

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

May-11

Trimble County 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

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	))))))	CASE NO. 2011-00162

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. I am not at this time. When LG&E 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 Mill Creek and Trimble County Generating Stations, which it anticipates doing by this August, it will file copies of the applications in the record of this proceeding.

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 LG&E's 2011 Environmental

Compliance Plan ("2011 Plan") and demonstrate how those facilities will allow LG&E 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 LG&E's compliance with the requirements of the Clean Air Act as amended ("CAAA"), the new National Ambient Air Quality Standard, the proposed Clean Air Transport Rule ("CATR"), the proposed national emission standards for hazardous air pollutants ("HAPs Rule"), and other environmental regulations that apply to LG&E'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 and all subsequent amendments to, and revisions of, it and other environmental laws and regulations have significantly increased LG&E'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 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 LG&E'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, LG&E is regulated by federal, state, and local 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 LG&E coal-fired units in Kentucky outside of Jefferson County (i.e., Trimble County Units 1 and 2) 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. For LG&E's units inside Jefferson County (i.e., units at the Mill Creek and Cane Run Generation Stations), Kentucky Revised Statutes Chapter 77 grants the Louisville Metro Air Pollution Control District ("LMAPCD") primacy for implementing the Jefferson County portion of the State Implementation Plan.

At issue in this Application is the effect of EPA's new 1-hour sulfur dioxide ("SO_2") National Ambient Air Quality Standard ("NAAQS"), CATR, and HAPs Rule on LG&E's Mill Creek Generating Station and its Trimble County Unit 1.

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

A. Yes. My testimony describes the environmental regulations and permit requirements applicable to LG&E, and Column 5 of LG&E's 2011 Plan (Exhibit JNV-1) summarizes these regulations and requirements. The pollution control facilities listed as Projects 26-27 of the 2011 Plan will enable LG&E to continue to fulfill its environmental compliance obligations. The environmental permits applicable to the proposed projects are set out in Column 6 of LG&E's 2011 Plan.

Q. What are the environmental regulations driving LG&E's 2011 Plan?

A. First, the EPA finalized a new 1-hour SO_2 NAAQS in June 2010, which required state and local air pollution control agencies to develop implementation plans for any non-attainment area. Jefferson County has already begun recording SO_2 levels in excess of the new 1-hour NAAQS. According to the CAAA for NAAQS, the LMAPCD must declare the county to be in "non-attainment" of the standard, which the EPA must confirm within 1 year. After that, the LMAPCD must file, and the EPA must approve, a plan to bring the county back into attainment. Emission sources must then take actions to reduce SO_2 emissions consistent with the approved plan. As the largest SO_2 emitter in Jefferson County, the Mill Creek Station will need to reduce its SO_2 emissions, which has been true of all the previous SO_2 non-attainment plans developed by the LMAPCD.

There are also two proposed EPA air-quality regulations driving what LG&E 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 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).

<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 CAIR, 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 NAAQS for $PM_{2.5}$ and eight-hour ozone (smog). (SO_2 is a precursor of $PM_{2.5}$, and NO_X is a precursor of $PM_{2.5}$ and ozone.) The rule applies to the eastern 28 states (including Kentucky) and the District of Columbia. It reduces emissions through cap-and-trade, allowance-based programs, and allows for open, interstate trading of SO_2 and NO_X allowances.

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

[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[.]").

[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).

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

Q. What steps does LG&E propose to take to comply with NAAQS and CATR?

A. As discussed in greater detail in Mr. Voyles's testimony, Project 26 of LG&E's 2011 Plan contains elements to reduce SO_2 and NO_X emissions. Specifically, to address SO_2 emissions LG&E proposes to build two new flue-gas desulfurization units ("FGDs"), one to serve Mill Creek Units 1 and 2 and another to serve Mill Creek Unit 4, and to tie Mill Creek Unit 3 into the existing FGD serving Unit 4 after installing performance upgrades to the FGD. (LG&E proposes to remove the existing FGDs for Mill Creek Units 1, 2, and 3.) Also under Project 26, LG&E proposes to address NO_X emissions by modifying facilities at Mill Creek Units 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, and by upgrading the Mill Creek Unit 4 SCR. As more fully described in Mr. Voyles's testimony and the testimony of Charles R. Schram, these FGD- and SCR-related project elements are the most cost-effective way for LG&E to comply with CATR.

[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.

Q. Why is LG&E 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. **To the extent the proposed FIPs do not fully address all significant transport, EPA is committed to assuring that any additional reductions needed are addressed quickly**."[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.

The Clean Air Mercury Rule and the National Emission Standards for Hazardous Air Pollutants

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

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

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 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

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

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 ("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).

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[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).

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

On March 29, 2005, EPA chose the second alternative and de-listed electric generating units as a regulated source group under Section 112, then promulgated the final CAMR under Section 111 on May 18, 2005. CAMR created a cap-and-trade, allowance-based system to reduce electric generating unit mercury emissions that was to be implemented in two phases. In Phase I (2010-2017), mercury emissions were to be capped at 38 tons nationwide. In Phase II (2018 and beyond), mercury emissions were to be reduced to 15 tons nationwide. In addition to the basic cap-and-trade system that covered all electric generating units, CAMR implemented a mercury emission limit for new electric generating units (or those subject to new-source standards due to having made major modifications). For bituminous-coal-fired units like LG&E'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, on Trimble County Unit 2 ("TC2"). To meet that requirement, LG&E and KU installed, with this Commission's approval,[15] the same kind of mercury-emission control system on TC2 that LG&E now proposes to install on its Mill Creek units and Trimble County Unit 1 (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

[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).

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), and so EPA could not regulate existing electric generating units under a Section-111-based scheme. Finding that the regulation of existing electric generating units was integral to EPA's overall regulation of mercury emissions, the court vacated the entire regulation and remanded the matter to EPA either to de-list electric generating units from Section 112 after making the appropriate factual findings or to issue appropriate HAPs regulations for electric generating units under Section 112.

EPA chose the latter course, and on 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 LG&E'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

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

[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."

equals the Title V permit requirement for our new TC2 which is an extremely low emitter of mercury.

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 measuring HCl, and this is the measure LG&E 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 LG&E propose to take to comply with the HAPs Rule?

A. The Mill Creek FGD work LG&E proposes under Project 26 to comply with NAAQS and CATR will also allow LG&E to comply with the HAPs Rule's SO_2 emission limit as a surrogate for HCl; there are no additional measures in the 2011 Plan to meet that requirement.

Concerning the particulate matter and mercury emissions limits imposed by the HAPs Rule, LG&E proposes to install Particulate Matter Control Systems to serve all of its Mill Creek units and Trimble County Unit 1, 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, a lime injection system to protect the baghouses from the corrosive effects of sulfuric acid mist

("SAM") and balance of plant modifications impacted from the implementation of the fabric filter. These facilities are contained in Projects 26 and 27 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 LG&E to comply with the HAPs Rule.

Q. Why is LG&E 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]

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, LG&E 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

[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).").
[19] 42 U.S.C. § 7412(i)(3)(A).

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 LG&E 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:

> 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

[20] 42 U.S.C. § 7412(i)(3)(B).

[21] 42 U.S.C. § 7412(i)(4).

[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).

> position to have assurance that the 1-year extension will be granted in those situations where it is appropriate.[23]

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

Recommendation

Q. What is your recommendation to the Commission?

A. The EPA's proposed CATR and HAPs Rule have created significant compliance obligations that LG&E cannot ignore, and any delay in beginning to take action to put in place the proposed compliance measures will serve only to place LG&E's customers at risk of bearing much higher compliance costs to achieve the same ends. I therefore recommend that the Commission approve LG&E's 2011 Plan as filed.

Q. Does this conclude your testimony?

A. Yes it does.

---

[23] *Id.*

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

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	))))))	**CASE NO. 2011-00162**

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' 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 exhibit, which was prepared under my direction:

Exhibit CRS-1 2011 Air Compliance Plan

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain the methods by which LG&E 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 LG&E's 2011 Plan?

A. LG&E's 2011 Plan consists of: (1) removing the current Flue Gas Desulfurization ("FGD") systems on Mill Creek Units 1, 2, and 3, building two new FGDs (one to serve Mill Creek Units 1 and 2, another to serve Mill Creek Unit 4), and tying Mill Creek Unit 3 into the existing Mill Creek Unit 4 FGD; (2) constructing Particulate Matter Control Systems to serve all four Mill Creek units and Trimble County Unit 1; (3) modifying Mill Creek Units 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 (4) upgrading the SCR at Mill Creek Unit 4. These programs 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 require 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 26 and 27: Mill Creek and Trimble County Unit 1 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 Mill Creek and Trimble County Unit 1 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. The Mill Creek and Trimble County Unit 1 air compliance projects were evaluated on a grouped-unit basis or an individual unit basis, depending on the configuration of the environmental controls. The analysis separated the units as follows: Mill Creek Units 1-2 (because of the proposed single wet flue-gas desulfurization system to serve both generating units), Mill Creek Unit 3, Mill Creek Unit 4, and Trimble County Unit 1. In evaluating the unit retirement options, a least-cost resource expansion plan was developed to replace the retired capacity. The replacement generation technology 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 Mill Creek units and Trimble County Unit 1 results in a lower PVRR for each unit, as shown in Table 1 below.

Table 1:
PVRR Savings for Mill Creek Units and Trimble County Unit 1
(Compared to Retiring the Units)

Unit	PVRR Savings ($ millions)	Capital Cost ($ millions)
Mill Creek 1 and 2	1,022	666
Mill Creek 3	756	225
Mill Creek 4	859	386
Trimble County 1	993	124

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 LG&E's Mill Creek station, which is equipped with SCRs on Units 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 Cane Run generating units resulted in a recommendation to retire those units. The retirement of Cane Run Units 4 and 5 results in lower PVRR of $88 million and $58 million, respectively, compared to installing controls. In the case of Cane Run 6, the difference in PVRR between installing controls and retiring the unit is negligible ($8 million). If LG&E installs controls on Cane Run 6 and the PVRR of a future expenditure not contemplated in this analysis exceeds $8 million, then installing controls would not be the least-cost option. Because the likelihood of future expenditures of this minimal level is considered high, LG&E does not recommend installing environmental controls on Cane Run 6. 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.

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 programs proposed in LG&E'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

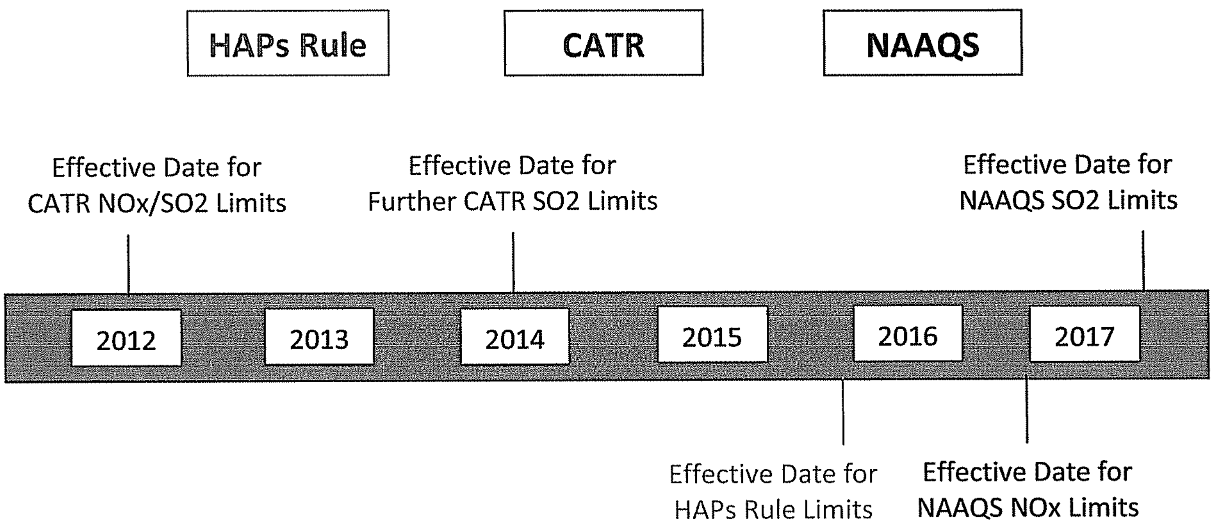
Generation Planning & Analysis
May 2011

Table of Contents

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.

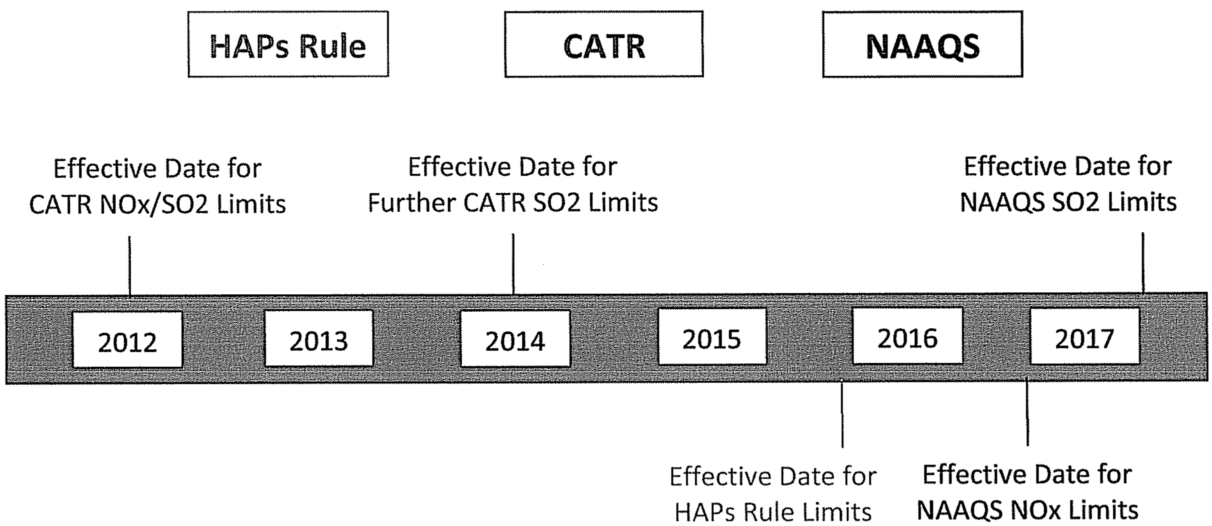
Table 3 – Proposed Capital Costs

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.

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[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

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	))))))	CASE NO. 2011-00162

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 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 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 LG&E's reporting and accounting for the operation and maintenance expenses associated with the pollution control projects in LG&E's 2011 Environmental Compliance Plan ("2011 Plan"), to demonstrate that the environmental compliance costs LG&E 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 LG&E seeking recovery of operation and maintenance expenses associated with some of the projects included in its proposed 2011 Plan?

A. Yes, LG&E is seeking recovery of operating and maintenance ("O&M") expenses for Projects 26 and 27, which relate to various installations and modifications to existing equipment LG&E has proposed in order to comply with existing and proposed regulations. Specifically, with its 2011 Plan, LG&E is proposing to install new flue gas desulfurization ("FGD") equipment to remove sulfur dioxide ("SO_2") from the exhaust flue gases at Mill Creek Generating Station ("Mill Creek") Units 1, 2 and 4, and to upgrade the FGD presently connected to Mill Creek Unit 4 and then connect it to serve Mill Creek Unit 3. LG&E's 2011 Plan also includes the construction of Particulate Matter Control Systems to serve all Mill Creek units and Trimble County Unit 1 ("TC1"). 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"). LG&E proposes to recover the O&M costs for the items above through the environmental surcharge mechanism to the extent they are not already contained in base rates.

Also, as Mr. Voyles's testimony describes in detail, LG&E proposes to make modifications to Mill Creek Units 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. LG&E 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. LG&E also proposes to upgrade the SCR at Mill Creek Unit 4 as part of Project 26. As noted in the testimony of Mr. Voyles, the turn-down modifications or the upgrade to the SCR at Mill Creek Unit 4 included in Project 26 are not expected to change the O&M associated with the SCRs.

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 LG&E identify the O&M expenses associated with these projects in its 2011 Plan?

A. LG&E's accounting system permits the tracking of costs in accordance with the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts. LG&E 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. LG&E 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 rate 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 LG&E's 2008 base rate case, Case No. 2008-00252, which was consolidated with LG&E's most recent depreciation study case, Case No. 2007-00564.[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 26 and 27 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. 2009-00549. In

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[1] *In the Matter of: Application of Louisville Gas and Electric Company to File Depreciation Study*, Case No. 2007-00564, and *In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Base Rates*, Case No. 2008-00252, Order at 10 (Feb, 5, 2009).

making that determination, the Commission evaluated the reasonableness of LG&E'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 LG&E during or prior to the twelve-month period ending October 31, 2009, or included as adjustments thereto, for which LG&E is seeking recovery in this case.

Q. Are any of the O&M expenses associated with the pollution control facilities in Project 26 in the 2011 Plan already included in existing base rates?

A. The test period in the last rate case reflects O&M costs associated with the four FGDs at Mill Creek. As discussed in the testimony of Mr. Conroy, the baseline methodology previously approved by this Commission in Case No. 2009-00198 will be used for determining the O&M expense associated with the Mill Creek FGDs to be recovered through the environmental surcharge requested in this case. This baseline methodology is presently used by LG&E and KU for certain projects approved for recovery through the ECR in Case Nos. 2009-00197 and -00198. The baseline methodology for determining the appropriate O&M for ECR accounting purposes has a long, consistent and successful history of use in environmental surcharge proceedings, going back to the first application of the surcharge.[2]

[2] *See, e.g., 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*, Case No. 93-465, Order at 15 (July 19, 1994) ("Finally, the O&M expense baseline should be the 12 months ending May 31, 1994, the period immediately preceding the first expense month to be included in the surcharge.").

There are no O&M expenses associated with the Particulate Matter Control Systems to serve the Mill Creek units in the test period from the last base rate case. All of the components of these systems—baghouses, PAC injection, and lime injection—will be new construction, and so were not in service during the test period in Case No. 2009-00549. Therefore, there are no O&M expenses in base rates from the last rate case associated with the proposed Particulate Matter Control Systems for Mill Creek.

In LG&E's 2006 Plan Case No. 2006-00208, the Commission approved separate SAM mitigation systems for Mill Creek Units 3 and 4 as part of Project 19; however, as Mr. Voyles explains in his testimony, LG&E has not yet built those systems, and there is no O&M associated with those systems in base rates or being recovered through the environmental surcharge mechanism. As discussed in the testimony of Mr. Conroy, LG&E is proposing to report the SAM-sorbent-O&M expenses for Mill Creek Units 3 and 4 (approved as part of Project 19) as part of the overall SAM-sorbent (baghouse lime) O&M expenses for the Particulate Matter Control Systems in Project 26. 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 any reasonable certainty. The other reason for this reporting approach is that LG&E 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.

Finally, concerning the SCR-related work at Mill Creek in Project 26, the SCRs at Mill Creek Units 3 and 4 were in operation during the test period in the last rate case; however, as discussed in the testimony of Mr. Voyles, neither the proposed turn-down modifications to the generating units (Mill Creek Units 3 and 4) nor the proposed upgrade to the Mill Creek Unit 4 SCR should affect the level of O&M associated with the SCRs. Accordingly, LG&E is not proposing to seek recovery of O&M associated with the SCRs through the environmental surcharge in this case. The capital and operating costs of the SCRs will remain base rate items.

Q. Are any of the O&M expenses associated with the new pollution control facilities in Project 27 in the 2011 Plan already included in existing base rates?

A. No, there are no O&M expenses for which LG&E is seeking recovery in this filing associated with the Particulate Matter Control System for TC1 in Project 27 that are already in existing base rates. There is a separate SAM mitigation system already in place at TC1, which the Commission approved as part of LG&E's 2006 Plan (Project 19); however, LG&E recovers the O&M costs of the existing TC1 SAM mitigation system through the environmental surcharge mechanism, not base rates. As discussed in the testimony of Mr. Conroy, LG&E is proposing to report the SAM-sorbent-O&M expenses for TC1 (approved as part of Project 19) as part of the overall SAM-sorbent (baghouse lime) O&M expenses for the

Particulate Matter Control System in Project 27 for the same reasons cited above concerning SAM-sorbent-O&M cost reporting for Mill Creek.

Q. Will the installation of the new pollution control facilities in LG&E's 2011 ECR Plan replace or cause existing facilities to be removed from service?

A. Yes. LG&E estimates that the retirement of the FGDs at Mill Creek Units 1, 2, and 3 will result in removing from service existing assets with an installed cost totaling $171 million. The amount of retirements for the upgrades to the Mill Creek Unit 4 FGD to allow it to be used for Mill Creek Unit 3 cannot be readily identified with reasonable accuracy until construction is complete. The addition of the Particulate Matter Control Systems included in Projects 26 and 27 will result in the removal from service of some additional 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 relates to 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 LG&E 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, LG&E 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 LG&E'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 LOUISVILLE GAS AND ELECTRIC COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	))))))	CASE NO. 2011-00162

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 LG&E Environmental Surcharge Monthly Reports
Exhibit RMC-4	Proposed LG&E 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 LG&E's Electric 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 LG&E's 2011 Environmental Compliance Plan ("2011 Plan").

Q. Is LG&E proposing any changes to its Environmental Cost Recovery Surcharge tariff?

A. Yes. LG&E is proposing some minor clarifying changes to its Environmental Cost Recovery Surcharge tariff. LG&E 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 LG&E's 2011 Plan?

A. No. LG&E will use the currently approved methodologies for calculating the environmental surcharge as specified by the Commission in Case Nos. 2000-386 ("2001 Plan"),[1] 2002-00147 ("2003 Plan"),[2] 2004-00421 ("2005 Plan"),[3] 2006-00208

[1] *In the Matter of: The Application of Louisville Gas and Electric 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 Louisville Gas and Electric Company for Approval of Its 2002 Compliance Plan for Recovery by Environmental Surcharge.*

[3] *In the Matter of: The Application of Louisville Gas and Electric Company for Approval of Its 2004 Compliance Plan for Recovery by Environmental Surcharge.*

("2006 Plan"),[4] and 2009-00198 ("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 LG&E's 2011 Plan?

A. Yes. LG&E 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 LG&E currently uses when filing its monthly environmental surcharge report. Exhibit RMC-4 shows the illustrative monthly environmental surcharge report forms LG&E is proposing in this case.

Q. Please describe the modifications that LG&E is proposing as a result of the 2011 Plan.

A. The calculation of the monthly billing factor for recovery of the cost of LG&E's 2011 Plan will be consistent with the methodology approved by the Commission in Case No. 2009-00311 and used to calculate the recovery of the cost of LG&E'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.

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[4] *In the Matter of: The Application of Louisville Gas and Electric Company for Approval of Its 2006 Compliance Plan for Recovery by Environmental Surcharge.*

[5] *In the Matter of: The Application of Louisville Gas and Electric Company for a Certificate 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 Louisville Gas and Electric Company for the Two-Year Billing Period Ending April 30, 2009* (Case No. 2009-00311) 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 LG&E is seeking cost recovery. With the elimination of the 2001 and 2003 Plans in Case No. 2009-00549,[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 both the incremental O&M expenses and the baseline methodology associated with the 2011 Plan projects as discussed below in my testimony. The projects for the 2001 and 2003 Plans are being removed from the form. Also removed from ES Form 2.50 is the Ash Pond Dredging Expense associated with the 2005 Plan. This item is being removed because the related deferred debit balance was fully amortized in April 2010.

Moreover, LG&E has proposed to remove several line items that are no longer used from ES Form 2.00. The Monthly Insurance Expense and Monthly Permitting Fees are not being recovered through the ECR mechanism and have been removed from the Determination of Pollution Control Operating Expenses section. The "Occurring Since Last Roll-in of Surcharge into Existing Rates" line is not used and

[7] The Commission's final order in LG&E'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 Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Base Rates* (Case No. 2009-00549), Order, July 30, 2010.

has been removed from the form. The "Less Operating Expenses Associated with Retirements" line is being removed and will be shown on ES Form 2.50 as the Base Rate Baseline. The Mill Creek Ash Dredging deferred debit balance in the Determination of Environmental Compliance Rate Base and the associated amortization in the Determination of Pollution Control Operating Expenses have been removed due to the deferred debit balance having been fully amortized as of April 2010.

Q. Please describe the baseline methodology for the O&M expenses associated with the 2011 Plan project.

A. As discussed in the testimony of Shannon L. Charnas, there are O&M expenses associated with the existing Flue Gas Desulfurization ("FGD" or "scrubber") equipment at Mill Creek (Project 26) included in existing base rates for LG&E. LG&E is requesting the inclusion of capital costs and O&M expenses associated with three new FGDs and an upgrade for the fourth FGD at Mill Creek station in the 2011 Plan. LG&E is proposing to establish a baseline of FGD expenses that are included in base rates in order to determine the appropriate scrubber O&M expenses to include in the monthly ECR filing. ES Form 2.50 is being modified to include a baseline of scrubber O&M expenses to be subtracted from total scrubber O&M expenses at Mill Creek on a monthly basis. As of the most recent base rate case (test year ending October 31, 2009) there is $8.85 million of annual O&M expense associated with the FGDs at Mill Creek including in base rates. However, this baseline amount will change over time as base rates change prior to the in-service date of the proposed FGD projects associated with the 2011 Plan.

Q. Please describe LG&E's proposal concerning the reporting of sulfuric acid mist ("SAM") sorbent O&M expenses currently being recovered through the environmental surcharge mechanism.

A. LG&E currently recovers through the environmental surcharge mechanism as part of Project 19 (2006 Plan) the SAM-sorbent-O&M costs related to the SAM mitigation system installed at Trimble County Unit 1 ("TC1"). Also, the Commission approved as part of Project 19 SAM mitigation systems for Mill Creek Units 3 and 4, though LG&E has not yet built those facilities (but it now plans to do so in the near future).

As described in the testimony of John N. Voyles, LG&E proposes to install Particulate Matter Control Systems to serve all four Mill Creek units and TC1. 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 26 for Mill Creek and Project 27 for TC1, LG&E proposes to report the SAM-sorbent-O&M costs of the SAM mitigation systems for Mill Creek Units 3 and 4 and TC1 as part of the SAM-sorbent (baghouse lime) O&M costs associated with Projects 26 and 27. In other words, instead of reporting the SAM-sorbent-O&M costs for Mill Creek Units 3 and 4, and TC1 under the 2006 Plan on ES Form 2.50, LG&E proposes to report them under the 2011 Plan on ES Form 2.50.

LG&E 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, LG&E

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 Ms. 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, LG&E is not proposing to re-open or amend Project 19; rather, LG&E 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 26 and 27) to comport with practical necessity and to provide clearer reporting to the Commission.

Q. Has LG&E 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 an electric customer is an increase of 2.3% initially in 2012 and increasing to a maximum of 19.2% in 2016. For a residential electric customer using 1,000-kilowatt hours per month, the initial monthly increase is expected to be $1.96 in 2012, upon approval by the Commission. It is estimated that this amount will increase to a maximum of $16.33 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)	$25,243	$76,600	$127,031	$218,209	$248,966
12 Month Average Jurisdictional Ratio	87.20%	87.20%	87.20%	87.20%	87.20%
Jurisdictional E(m) - ($000)	$22,012	$66,797	$110,774	$190,284	$217,105
Forecasted Jurisdictional R(m) - (million)	$956	$1,013	$1,038	$1,077	$1,131
Incremental Billing Factor	2.30%	6.60%	10.67%	17.67%	19.20%
Residential Customer Impact					
Monthly bill (1,000 kWh per month)	$1.96	$5.61	$9.08	$15.03	$16.33

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.

Louisville Gas and Electric Company

P.S.C. Electric No. 8, First Revision of Original Sheet No. 87
Canceling P.S.C. Electric No. 8, 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, 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 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, Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 8, First Revision of Original Sheet No. 87
Canceling P.S.C. Electric No. 8, Original Sheet No. 87

Adjustment Clause **ECR**

Environmental Cost Recovery Surcharge

APPLICABLE

In all territory served.

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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.

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   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, 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.
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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
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Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Deleted: To electric rate schedules . RS, VFD, GS, CPS, PS, CTODS, ITODS, CTODP, ITODP, RTS, FLS, LS, RLS, LE, TE, LEV, FAC, and DSM.

Deleted: CESF

Deleted: CESF = Current Environmental Surcharge Factor¶
. . . ¶

Deleted: as set forth below.

Deleted: Insurance

Deleted: prior amended

Deleted: August 6, 2010

Deleted: August 1, 2010

Deleted: Issued by Authority of an Order of the KPSC in Case No. 2009-00549 dated July 30, 2010

ES FORM 1.00

LOUISVILLE GAS AND ELECTRIC 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 15 =

Effective Date for Billing:

Submitted by: ______________________________

Title: Director, Rates

Date Submitted:

ES FORM 1.10

LOUISVILLE GAS AND ELECTRIC 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

LOUISVILLE GAS AND ELECTRIC 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 - Emission Allowances per ES Form 2.31, 2.32 and 2.33		
Cash Working Capital Allowance		
Deferred Debit Balance -- Mill Creek Ash Dredging		
Subtotal		
Deductions:		
Accumulated Depreciation on Eligible Pollution Control Plant		
Pollution Control Deferred Income Taxes		
Subtotal		
Environmental Compliance Rate Base		

Determination of Pollution Control Operating Expenses

	Enviromental Compliance Plan
Monthly Operations & Maintenance Expense	
Monthly Depreciation & Amortization Expense	
less investment tax credit amortization	
Monthly Property and Other Applicable Taxes	
Monthly Insurance Expense	
Monthly Emission Allowance Expense from ES Form 2.31, 2.32 and 2.33	
Monthly Permitting Fees	
Amortization of Monthly Mill Creek Ash Dredging	
Less : Operating Expenses Associated with Retirements or Replacements	
Occuring Since Last Roll-In of Surcharge into Existing Rates	
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			

LOUISVILLE GAS AND ELECTRIC 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	Deferred Tax Balance as of #REF!	Monthly ITC Amortization Credit	Monthly Depreciation Expense	Monthly Property Tax Expense
				(2)-(3)+(4)				
2001 Plan:								
Project 6 - LGE NOx								
Subtotal								
Less Retirements and Replacement resulting from implementation of 2001 Plan								
Net Total - 2001 Plan:								
2003 Plan:								
Project 7 - Mill Creek FGD Scrubber Conversion								
Project 8 - Precipitator Upgrades - All Plants								
Project 9 - Clearwell Water System - Mill Creek								
Project 10 - SO_2 Absorber Trays - Mill Creek 3 & 4								
Subtotal								
Less Retirements and Replacement resulting from implementation of 2003 Plan								
Net Total - 2003 Plan:								
2005 Plan:								
Project 11 - Special Waste Landfill Expansion at Mill Creek								
Project 12 - Special Waste Landfill Expansion at Cane Run Station								
Project 13 - Scrubber Refurbishment at Trimble County Unit 1								
Project 14 - Scrubber Refurbishment at Cane Run Unit 6								
Project 15 - Scrubber Refurbishment at Cane Run Unit 5								
Project 16 - Scrubber Improvements at Trimble County Unit 1								
Subtotal								
Less Retirements and Replacement resulting from implementation of 2005 Plan								
Net Total - 2005 Plan:								

LOUISVILLE GAS AND ELECTRIC 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	Deferred Tax Balance as of #REF!	Monthly ITC Amortization Credit	Monthly Depreciation Expense	Monthly Property Tax Expense
				(2)-(3)+(4)				
2006 Plan:								
Project 18 - TC2 AQCS Equipment								
Project 19 - Sorbent Injection								
Project 20 - Mercury Monitors								
Project 21 - Mill Creek Opacity and Particulate Monitors								
Subtotal								
Less Retirements and Replacement resulting from implementation of 2006 Plan								
Net Total - 2006 Plan:								
2009 Plan:								
Project 22 - Cane Run CCP Storage (Landfill - Phase I)								
Project 23 - Trimble County Ash Treatment Basin (BAP/GSP)								
Project 24 - Trimble County CCP Storage (Landfill - Phase I)								
Project 25 - 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%.

LOUISVILLE GAS AND ELECTRIC 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.

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Inventory of Emission Allowances (SO_2) - Current Vintage Year

For the Expense Month of

	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 KU							
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

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Inventory of Emission Allowances (NOx) - Ozone Season Allowance Allocation

For the Expense Month of

	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 KU:							
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.

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Inventory of Emission Allowances (NOx) - Annual Allowance Allocation

For the Expense Month of

	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 KU:							
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

LOUISVILLE GAS AND ELECTRIC 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	$	-

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Pollution Control - Operations & Maintenance Expenses
For the Month Ended:

O&M Expense Account	Cane Run	Mill Creek	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				
Ashpond Dredging Expense				
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				
502056 - ECR Scrubber Operations				
512055 - ECR Scrubber Maintenance				
506154 - ECR NOx Operation -- Consumables				
506155 - ECR NOx Operation -- Labor and Other				
512151 - ECR NOx Maintenance				
506051 - ECR Precipitator Operation				
506151 - ECR Activated Carbon				
512051 - ECR Precipitator Maintenance				
Total 2006 Plan O&M Expenses				
2009 Plan				
502012 - ECR Landfill Operations				
512105 - ECR Landfill Maintenance				
Adjustment for CCP Disposal in Base Rates (ES Form 2.51)				
Net 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

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT
CCP Disposal Facilities Expenses
For the Month Ended:

	On-Site CCP Disposal O&M Expense	Cane Run	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.

ES FORM 2.60

LOUISVILLE GAS AND ELECTRIC 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			$ -

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Beneficial Reuse Opportunities
For the Month Ended:

	On-Site CCP Disposal O&M Expense	Cane Run	Mill Creek	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 25				
(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 25 [(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

LOUISVILLE GAS AND ELECTRIC 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 =		

LOUISVILLE GAS AND ELECTRIC 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		
Total Kentucky Jurisdictional Revenues for Environmental Surcharge Purposes =		
Non -Jurisdictional Revenues		
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		
Miscellaneous		
Total Company Revenues per Income Statement =		

ES FORM 1.00

LOUISVILLE GAS AND ELECTRIC 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

LOUISVILLE GAS AND ELECTRIC 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

LOUISVILLE GAS AND ELECTRIC 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 - Emission Allowances per ES Form 2.31, 2.32 and 2.33		
Cash Working Capital Allowance		
Subtotal		
Deductions:		
Accumulated Depreciation on Eligible Pollution Control Plant		
Pollution Control Deferred Income Taxes		
Subtotal		
Environmental Compliance Rate Base		

Determination of Pollution Control Operating Expenses

	Enviromental Compliance Plan
Monthly Operations & Maintenance Expense	
Monthly Depreciation & Amortization Expense	
less investment tax credit amortization	
Monthly Property and Other Applicable Taxes	
Monthly Emission Allowance Expense from ES Form 2.31, 2.32 and 2.33	
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			

LOUISVILLE GAS AND ELECTRIC 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	Deferred Tax Balance as of	Monthly ITC Amortization Credit	Monthly Depreciation Expense	Monthly Property Tax Expense
				(2)-(3)+(4)				
2005 Plan:								
Project 11 - Special Waste Landfill Expansion at Mill Creek								
Project 12 - Special Waste Landfill Expansion at Cane Run Station								
Project 13 - Scrubber Refurbishment at Trimble County Unit 1								
Project 14 - Scrubber Refurbishment at Cane Run Unit 6								
Project 15 - Scrubber Refurbishment at Cane Run Unit 5								
Project 16 - Scrubber Improvements at Trimble County Unit 1								
Subtotal								
Less Retirements and Replacement resulting from implementation of 2005 Plan								
Net Total - 2005 Plan:								
2006 Plan:								
Project 18 - TC2 AQCS Equipment								
Project 19 - Sorbent Injection								
Project 20 - Mercury Monitors								
Project 21 - Mill Creek Opacity and Particulate Monitors								
Subtotal								
Less Retirements and Replacement resulting from implementation of 2006 Plan								
Net Total - 2006 Plan:								
2009 Plan:								
Project 22 - Cane Run CCP Storage (Landfill - Phase I)								
Project 23 - Trimble County Ash Treatment Basin (BAP/GSP)								
Project 24 - Trimble County CCP Storage (Landfill - Phase 1)								
Project 25 - Beneficial Reuse								
Subtotal								
Less Retirements and Replacement resulting from implementation of 2009 Plan								
Net Total - 2009 Plan:								
2011 Plan:								
Project 26 - Mill Creek Station Air Compliance								
Project 27 - Trimble County Unit 1 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%.

LOUISVILLE GAS AND ELECTRIC 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.

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Inventory of Emission Allowances (SO_2) - Current Vintage Year

For the Expense Month of

	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 KU							
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

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Inventory of Emission Allowances (NOx) - Ozone Season Allowance Allocation

For the Expense Month of

	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 KU:							
Quantity							
Dollars							
$/Allowance							

Emission Allowance Expense for Other Power Generation is excluded from expense reported on Form 2.00 for recovery through the monthly billing factor.

ES FORM 2.33

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Inventory of Emission Allowances (NOx) - Annual Allowance Allocation

For the Expense Month of

	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 KU:							
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

LOUISVILLE GAS AND ELECTRIC 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	$	-

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Pollution Control - Operations & Maintenance Expenses
For the Month Ended:

O&M Expense Account	Cane Run	Mill Creek	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				
502056 - ECR Scrubber Operations				
512055 - ECR Scrubber Maintenance				
506154 - ECR NOx Operation -- Consumables				
506155 - ECR NOx Operation -- Labor and Other				
512151 - ECR NOx Maintenance				
506051 - ECR Precipitator Operation				
506151 - ECR Activated Carbon				
512051 - ECR Precipitator Maintenance				
Total 2006 Plan O&M Expenses				
2009 Plan				
502012 - ECR Landfill Operations				
512105 - ECR Landfill Maintenance				
Adjustment for CCP Disposal in Base Rates (ES Form 2.51)				
Net 2009 Plan O&M Expenses				
2011 Plan				
502056 - ECR Scrubber Operations				
512055 - ECR Scrubber Maintenance				
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				
Adjustment for Base Rates Baseline Amounts				
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

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT

CCP Disposal Facilities Expenses
For the Month Ended:

	On-Site CCP Disposal O&M Expense	Cane Run	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.

ES FORM 2.60

LOUISVILLE GAS AND ELECTRIC 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			

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Beneficial Reuse Opportunities
For the Month Ended:

On-Site CCP Disposal O&M Expense	Cane Run	Mill Creek	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 25				
(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 25 [(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%.

LOUISVILLE GAS AND ELECTRIC 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	Total Excluding Environmental Surcharge	Total Including Off-System Sales	Total	Total Excluding Environmental Surcharge
					(2)+(3)+(4)+(5)	(6)-(5)	(See Note 1)	(6)+(8)	(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 =		

LOUISVILLE GAS AND ELECTRIC 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		
Total Kentucky Jurisdictional Revenues for Environmental Surcharge Purposes =		
Non -Jurisdictional Revenues		
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		
Miscellaneous		
Total Company Revenues per Income Statement =		

Louisville Gas and Electric Company
Environmental Cost Recovery Surcharge Summary

	2012	2013	2014	2015	2016
Total E(m) - ($000)	$25,243	$76,600	$127,031	$218,209	$248,966
12 Month Average Jurisdictional Ratio	87.20%	87.20%	87.20%	87.20%	87.20%
Jurisdictional E(m) - ($000)	$22,012	$66,797	$110,774	$190,284	$217,105
Forecasted Jurisdictional R(m) - (million)	$956	$1,013	$1,038	$1,077	$1,131
Incremental Billing Factor	2.30%	6.60%	10.67%	17.67%	19.20%
Residential Customer Impact					
Monthly bill (1,000 kWh per month)	$1.96	$5.61	$9.08	$15.03	$16.33

Revenue Requirements Summary
2011 Amended Plan - LG&E

		2012	2013	2014	2015	2016	2017	2018	2019	2020
Project 26	**MC Air Compliance - All Units - FGDs & PM Control Systems**									
	Revenue Requirement									
	Eligible Plant	223,007,642	635,707,764	1,006,220,362	1,260,668,843	1,268,214,657	1,268,214,657	1,268,214,657	1,268,214,657	1,268,214,657
	Less: Retired Plant	-	-	(66,093,145)	(171,243,250)	(171,243,250)	(171,243,250)	(171,243,250)	(171,243,250)	(171,243,250)
	Less: Accumulated Depreciation	-	-	(2,051,239)	(40,402,159)	(92,361,100)	(144,320,041)	(196,278,982)	(248,237,922)	(300,196,863)
	Plus: Accumulated Depreciation on retired plant	-	-	33,754,526	107,305,608	107,305,608	107,305,608	107,305,608	107,305,608	107,305,608
	Less: Deferred Tax Balance	-	-	(5,075,817)	(13,943,352)	(27,194,621)	(38,060,062)	(46,720,057)	(53,337,644)	(58,067,671)
	Plus: Deferred Tax Balance on retired plant	-	-	3,536,499	5,341,429	5,341,429	5,341,429	5,341,429	5,341,429	5,341,429
	Environmental Compliance Rate Base	223,007,642	635,707,764	970,291,187	1,147,727,118	1,090,062,723	1,027,238,342	966,619,405	908,042,877	851,353,909
	Rate of return	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%
		$ 25,228,303	$ 71,916,049	$ 109,766,644	$ 129,839,533	$ 123,316,102	$ 116,208,935	$ 109,351,265	$ 102,724,647	$ 96,311,564
	Operating expenses	-	1,693,407	7,079,485	31,875,906	47,403,071	48,528,230	49,675,892	50,846,507	52,040,535
	Annual Depreciation expense	-	-	2,051,239	38,350,920	51,958,941	51,958,941	51,958,941	51,958,941	51,958,941
	Less depreciation on retired plant	-	-	206,498	(907,630)	(907,630)	(907,630)	(907,630)	(907,630)	(907,630)
	Annual Property Tax expense	14,428	334,511	953,562	1,506,254	1,830,400	1,763,780	1,685,842	1,607,904	1,529,965
	Total OE	$ 14,428	$ 2,027,919	$ 10,290,783	$ 70,825,449	$ 100,284,782	$ 101,343,321	$ 102,413,045	$ 103,505,721	$ 104,621,811
	Total E(m)	25,242,731	73,943,967	120,057,427	200,664,982	223,600,884	217,552,256	211,764,309	206,230,368	200,933,375

Revenue Requirements Summary
2011 Amended Plan - LG&E

		2012	2013	2014	2015	2016	2017	2018	2019	2020
Project 27	**TC1 Air Compliance - PM Control Systems**									
	Revenue Requirement									
	Eligible Plant	-	23,479,869	61,329,417	118,470,025	123,752,357	123,752,357	123,752,357	123,752,357	123,752,357
	Less: Retired Plant	-	-	-	-	-	-	-	-	-
	Less: Accumulated Depreciation	-	-	-	(536,077)	(5,015,912)	(9,495,748)	(13,975,583)	(18,455,418)	(22,935,254)
	Plus: Accumulated Depreciation on retired plant	-	-	-	-	-	-	-	-	-
	Less: Deferred Tax Balance	-	-	-	(1,395,029)	(2,985,498)	(4,336,446)	(5,466,435)	(6,391,372)	(7,127,169)
	Plus: Deferred Tax Balance on retired plant	-	-	-	-	-	-	-	-	-
	Environmental Compliance Rate Base	-	23,479,869	61,329,417	116,538,920	115,750,947	109,920,164	104,310,340	98,905,567	93,689,935
	Rate of return	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%
		$ -	$ 2,656,220	$ 6,938,045	$ 13,183,760	$ 13,094,619	$ 12,434,997	$ 11,800,371	$ 11,188,942	$ 10,598,911
	Operating expenses	-	-	-	3,732,365	7,614,024	7,766,305	7,921,631	8,080,064	8,241,665
	Annual Depreciation expense	-	-	-	536,077	4,479,835	4,479,835	4,479,835	4,479,835	4,479,835
	Less depreciation on retired plant	-	-	-	-	-	-	-	-	-
	Annual Property Tax expense	-	-	35,220	91,994	176,901	178,105	171,385	164,665	157,945
	Total OE	$ -	$ -	$ 35,220	$ 4,360,436	$ 12,270,761	$ 12,424,245	$ 12,572,851	$ 12,724,564	$ 12,879,446
	Total E(m)	-	2,656,220	6,973,265	17,544,196	25,365,379	24,859,241	24,373,222	23,913,506	23,478,356

Revenue Requirements Summary
2011 Amended Plan - LG&E

	2012	2013	2014	2015	2016	2017	2018	2019	2020
Total E(m) - All LG&E Projects	25,242,731	76,600,187	127,030,692	218,209,178	248,966,263	242,411,497	236,137,532	230,143,875	224,411,731
	25,242,731	76,600,187	127,030,692	218,209,178	248,966,263	242,411,497	236,137,532	230,143,875	224,411,731
Total Revenue Requirements									
Project 26	25,242,731	73,943,967	120,057,427	200,664,982	223,600,884	217,552,256	211,764,309	206,230,368	200,933,375
Project 27	-	2,656,220	6,973,265	17,544,196	25,365,379	24,859,241	24,373,222	23,913,506	23,478,356
Total	25,242,731	76,600,187	127,030,692	218,209,178	248,966,263	242,411,497	236,137,532	230,143,875	224,411,731
	-	-	-	-	-	-	-	-	-
12 Month Average Jurisdictional Ratio	87.20%	87.20%	87.20%	87.20%	87.20%	87.20%	87.20%	87.20%	87.20%
Jurisdictional Allocation	22,012,293	66,797,278	110,773,939	190,283,859	217,104,806	211,388,886	205,917,831	200,691,212	195,692,640
Forecasted 12-Month Retail Revenue	955,916,819	1,012,748,964	1,038,491,023	1,076,945,865	1,130,945,501	1,195,411,298	1,235,773,390	1,292,678,978	1,331,079,773
Billing Factor	2.30%	6.60%	10.67%	17.67%	19.20%	17.68%	16.66%	15.53%	14.70%
LGE 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 @ $0.07068	$70.68	$70.68	$70.68	$70.68	$70.68	$70.68	$70.68	$70.68	$70.68
FAC billings (Dec 10 factor - $0.00241/kWh)	$2.41	$2.41	$2.41	$2.41	$2.41	$2.41	$2.41	$2.41	$2.41
DSM billings (Dec 10 factor - $0.0035/kWh)	$3.50	$3.50	$3.50	$3.50	$3.50	$3.50	$3.50	$3.50	$3.50
ECR billings (Dec 10 factor: 1.29%)	$1.10	$1.10	$1.10	$1.10	$1.10	$1.10	$1.10	$1.10	$1.10
Additional ECR factor	$1.96	$5.61	$9.08	$15.03	$16.33	$15.05	$14.18	$13.21	$12.51

Revenue Requirements Project Detail
2011 Amended Plan - LG&E Project 26

	2012	2013	2014	April 2015	2016	2017	2018	2019	2020
In-Service				1	2	3	4	5	6
Mill Creek 2PC									
CapEx - Mill Creek FGDs - Combined MC1-MC2 new FGD	$ 50,384,502	$ 104,799,763	$ 108,991,754	$ 89,616,306	$ -	$ -	$ -	$ -	$ -
Accumulated Expenditures	$ 50,384,502	$ 155,184,265	$ 264,176,019	$ 353,792,325	$ 353,792,325	$ 353,792,325	$ 353,792,325	$ 353,792,325	$ 353,792,325
Book Depreciation rate, per year	0.000%	0.000%	0.000%	4.280%	4.280%	4.280%	4.280%	4.280%	4.280%
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	-	-	-	907,537	4,620,647	7,648,999	10,045,654	11,856,095	13,125,805
Book Accumulated Depreciation Balance	-	-	-	10,725,804	25,868,115	41,010,427	56,152,739	71,295,050	86,437,362
Unrecovered Investment -- Book	50,384,502	155,184,265	264,176,019	353,792,325	353,792,325	353,792,325	353,792,325	353,792,325	353,792,325
Book Depreciation	-	-	-	10,725,804	15,142,312	15,142,312	15,142,312	15,142,312	15,142,312
Unrecovered Investment -- Tax total	50,384,502	155,184,265	264,176,019	353,792,325	353,792,325	353,792,325	353,792,325	353,792,325	353,792,325
Tax Depreciation	-	-	-	13,267,212	25,540,268	23,622,714	21,853,752	20,212,156	18,697,924
Allowed Rate of Return	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%
Book Depreciation expense total	-	-	-	10,725,804	15,142,312	15,142,312	15,142,312	15,142,312	15,142,312
Tax Depreciation expense total	-	-	-	13,267,212	25,540,268	23,622,714	21,853,752	20,212,156	18,697,924
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	-	-	-	907,537	3,713,110	3,028,352	2,396,655	1,810,441	1,269,709
Revenue Recovery on Capital Expenditure to date									
Eligible Plant, cumulative capital expenditures	50,384,502	155,184,265	264,176,019	353,792,325	353,792,325	353,792,325	353,792,325	353,792,325	353,792,325
Less: Retired Plant	-	-	-	(91,533,054)	(91,533,054)	(91,533,054)	(91,533,054)	(91,533,054)	(91,533,054)
Less: Accumulated Depreciation	-	-	-	(10,725,804)	(25,868,115)	(41,010,427)	(56,152,739)	(71,295,050)	(86,437,362)
Plus: Accumulated Depreciation on Retired Plant	-	-	-	67,043,393	67,043,393	67,043,393	67,043,393	67,043,393	67,043,393
Less: Deferred Tax Balance	-	-	-	(907,537)	(4,620,647)	(7,648,999)	(10,045,654)	(11,856,095)	(13,125,805)
Plus: Deferred Tax Balance on Retired Plant	-	-	-	1,722,429	1,722,429	1,722,429	1,722,429	1,722,429	1,722,429
Environmental Compliance Rate Base	50,384,502	155,184,265	264,176,019	319,391,751	300,536,329	282,365,666	264,826,699	247,873,946	231,461,925
Rate of return	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%
Return on Environmental Compliance Rate Base	$ 5,699,874	$ 17,555,612	$ 29,885,580	$ 36,132,000	$ 33,998,932	$ 31,943,330	$ 29,959,190	$ 28,041,367	$ 26,184,716
Operating Expenses	-	-	-	(236,824)	(294,074)	(228,759)	(162,138)	(94,185)	(24,872)
Annual Depreciation expense	-	-	-	10,725,804	15,142,312	15,142,312	15,142,312	15,142,312	15,142,312
Less depreciation on retired plant	-	-	-	(306,022)	(306,022)	(306,022)	(306,022)	(306,022)	(306,022)
Annual Property Tax expense	-	75,577	232,776	396,264	514,600	491,886	469,173	446,459	423,746
Total OE	$ -	$ 75,577	$ 232,776	$ 10,579,222	$ 15,056,815	$ 15,099,416	$ 15,143,324	$ 15,188,564	$ 15,235,163
Total E(m) - Project	5,699,874	17,631,189	30,118,357	46,711,221	49,055,747	47,042,746	45,102,514	43,229,931	41,419,878

Revenue Requirements Project Detail
2011 Amended Plan - LG&E Project 26

	2012	2013	November 2014	2015	2016	2017	2018	2019	2020
In-Service			1	2	3	4	5	6	7
Mill Creek 3PC									
CapEx - Mill Creek FGDs - MC3 FGD (Old MC4 FGD tied-in)	$ 6,892,461	$ 32,256,716	$ 29,819,542	$ 3,876,540	$ -	$ -	$ -	$ -	$ -
Accumulated Expenditures	$ 6,892,461	$ 39,149,176	$ 68,968,718	$ 72,845,258	$ 72,845,258	$ 72,845,258	$ 72,845,258	$ 72,845,258	$ 72,845,258
Book Depreciation rate, per year	0.000%	0.000%	3.850%	3.850%	3.850%	3.850%	3.850%	3.850%	3.850%
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	-	-	805,052	1,681,431	2,416,820	3,022,143	3,506,766	3,880,053	4,150,069
Book Accumulated Depreciation Balance	-	-	331,912	3,136,454	5,940,997	8,745,539	11,550,082	14,354,624	17,159,167
Unrecovered Investment -- Book	6,892,461	39,149,176	68,968,718	72,845,258	72,845,258	72,845,258	72,845,258	72,845,258	72,845,258
Book Depreciation	-	-	331,912	2,804,542	2,804,542	2,804,542	2,804,542	2,804,542	2,804,542
Unrecovered Investment -- Tax total	6,892,461	39,149,176	68,968,718	72,845,258	72,845,258	72,845,258	72,845,258	72,845,258	72,845,258
Tax Depreciation	-	-	2,586,327	5,258,699	4,863,878	4,499,652	4,161,650	3,849,872	3,560,676
Allowed Rate of Return	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%
Book Depreciation expense total	-	-	331,912	2,804,542	2,804,542	2,804,542	2,804,542	2,804,542	2,804,542
Tax Depreciation expense total	-	-	2,586,327	5,258,699	4,863,878	4,499,652	4,161,650	3,849,872	3,560,676
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	-	-	805,052	876,379	735,389	605,323	484,623	373,287	270,015
Revenue Recovery on Capital Expenditure to date									
Eligible Plant, cumulative capital expenditures	6,892,461	39,149,176	68,968,718	72,845,258	72,845,258	72,845,258	72,845,258	72,845,258	72,845,258
Less: Retired Plant	-	-	(66,093,145)	(66,093,145)	(66,093,145)	(66,093,145)	(66,093,145)	(66,093,145)	(66,093,145)
Less: Accumulated Depreciation	-	-	(331,912)	(3,136,454)	(5,940,997)	(8,745,539)	(11,550,082)	(14,354,624)	(17,159,167)
Plus: Accumulated Depreciation on Retired Plant	-	-	33,754,526	33,754,526	33,754,526	33,754,526	33,754,526	33,754,526	33,754,526
Less: Deferred Tax Balance	-	-	(805,052)	(1,681,431)	(2,416,820)	(3,022,143)	(3,506,766)	(3,880,053)	(4,150,069)
Plus: Deferred Tax Balance on Retired Plant	-	-	3,536,499	3,536,499	3,536,499	3,536,499	3,536,499	3,536,499	3,536,499
Environmental Compliance Rate Base	6,892,461	39,149,176	39,029,635	39,225,254	35,685,322	32,275,457	28,986,291	25,808,462	22,733,904
Rate of return	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%
Return on Environmental Compliance Rate Base	$ 779,727	$ 4,428,850	$ 4,415,326	$ 4,437,456	$ 4,036,992	$ 3,651,243	$ 3,279,147	$ 2,919,647	$ 2,571,830
Operating Expenses	-	-	(6,803)	211,745	270,192	329,808	390,615	452,639	515,904
Annual Depreciation expense	-	-	331,912	2,804,542	2,804,542	2,804,542	2,804,542	2,804,542	2,804,542
Less depreciation on retired plant	-	-	206,498	206,498	206,498	206,498	206,498	206,498	206,498
Annual Property Tax expense	-	10,339	58,724	102,955	104,563	100,356	96,150	91,943	87,736
Total OE	$ -	$ 10,339	$ 590,331	$ 3,325,741	$ 3,385,795	$ 3,441,204	$ 3,497,805	$ 3,555,622	$ 3,614,680
Total E(m) - Project	779,727	4,439,188	5,005,657	7,763,197	7,422,788	7,092,447	6,776,953	6,475,270	6,186,510

Revenue Requirements Project Detail
2011 Amended Plan - LG&E Project 26

	2012	2013	November 2014	2015	2016	2017	2018	2019	2020
In-Service			1	2	3	4	5	6	7
Mill Creek 4PC									
CapEx - Mill Creek FGDs - MC4 New FGD	$ 70,537,279	$ 87,592,561	$ 44,293,005	$ 11,842,514	$ -	$ -	$ -	$ -	$ -
Accumulated Expenditures	$ 74,586,491	$ 162,179,052	$ 206,472,057	$ 218,314,571	$ 218,314,571	$ 218,314,571	$ 218,314,571	$ 218,314,571	$ 218,314,571
Book Depreciation rate, per year	0.000%	0.000%	3.710%	3.710%	3.710%	3.710%	3.710%	3.710%	3.710%
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	-	-	2,422,991	5,158,612	7,471,689	9,394,965	10,956,507	12,184,379	13,102,749
Book Accumulated Depreciation Balance	-	-	957,514	9,056,985	17,156,455	25,255,926	33,355,397	41,454,867	49,554,338
Unrecovered Investment -- Book	74,586,491	162,179,052	206,472,057	218,314,571	218,314,571	218,314,571	218,314,571	218,314,571	218,314,571
Book Depreciation	-	-	957,514	8,099,471	8,099,471	8,099,471	8,099,471	8,099,471	8,099,471
Unrecovered Investment -- Tax total	74,586,491	162,179,052	206,472,057	218,314,571	218,314,571	218,314,571	218,314,571	218,314,571	218,314,571
Tax Depreciation	-	-	7,742,702	15,760,129	14,576,864	13,485,291	12,472,311	11,537,925	10,671,216
Allowed Rate of Return	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%
Book Depreciation expense total	-	-	957,514	8,099,471	8,099,471	8,099,471	8,099,471	8,099,471	8,099,471
Tax Depreciation expense total	-	-	7,742,702	15,760,129	14,576,864	13,485,291	12,472,311	11,537,925	10,671,216
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	-	-	2,422,991	2,735,621	2,313,077	1,923,276	1,561,541	1,227,872	918,370
Revenue Recovery on Capital Expenditure to date									
Eligible Plant, cumulative capital expenditures	74,586,491	162,179,052	206,472,057	218,314,571	218,314,571	218,314,571	218,314,571	218,314,571	218,314,571
Less. Retired Plant	-	-	-	-	-	-	-	-	-
Less: Accumulated Depreciation	-	-	(957,514)	(9,056,985)	(17,156,455)	(25,255,926)	(33,355,397)	(41,454,867)	(49,554,338)
Plus: Accumulated Depreciation on Retired Plant	-	-	-	-	-	-	-	-	-
Less: Deferred Tax Balance	-	-	(2,422,991)	(5,158,612)	(7,471,689)	(9,394,965)	(10,956,507)	(12,184,379)	(13,102,749)
Plus: Deferred Tax Balance on Retired Plant	-	-	-	-	-	-	-	-	-
Environmental Compliance Rate Base	74,586,491	162,179,052	203,091,552	204,098,975	193,686,427	183,663,680	174,002,668	164,675,325	155,657,484
Rate of return	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%
Return on Environmental Compliance Rate Base	$ 8,437,785	$ 18,346,915	$ 22,975,245	$ 23,089,213	$ 21,911,267	$ 20,777,418	$ 19,684,492	$ 18,629,313	$ 17,609,147
Operating Expenses	-	-	20,421	359,055	417,926	477,974	539,223	601,697	665,421
Annual Depreciation expense	-	-	957,514	8,099,471	8,099,471	8,099,471	8,099,471	8,099,471	8,099,471
Less depreciation on retired plant	-	-	-	-	-	-	-	-	-
Annual Property Tax expense	6,074	111,880	243,269	308,272	313,886	301,737	289,588	277,439	265,290
Total OE	$ 6,074	$ 111,880	$ 1,221,204	$ 8,766,797	$ 8,831,283	$ 8,879,182	$ 8,928,282	$ 8,978,607	$ 9,030,181
Total E(m) - Project	8,443,859	18,458,795	24,196,449	31,856,010	30,742,550	29,656,600	28,612,774	27,607,919	26,639,328

Revenue Requirements Project Detail
2011 Amended Plan - LG&E Project 26

	2012	2013	2014	May 2015	2016	2017	2018	2019	2020
In-Service				1	2	3	4	5	6
Mill Creek 1NPC									
CapEx - MC1 PM Control System - SAM Mitigation	$ 13,571,615	$ 42,786,743	$ 49,569,616	$ 48,617,414	$ -	$ -	$ -	$ -	$ -
Accumulated Expenditures	$ 13,571,615	$ 56,358,358	$ 105,927,974	$ 154,545,388	$ 154,545,388	$ 154,545,388	$ 154,545,388	$ 154,545,388	$ 154,545,388
Book Depreciation rate, per year	0.000%	0.000%	0.000%	4.240%	4.240%	4.240%	4.240%	4.240%	4.240%
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	-	-	-	607,070	2,251,125	3,596,060	4,665,055	5,477,977	6,054,693
Book Accumulated Depreciation Balance	-	-	-	4,095,453	10,648,177	17,200,902	23,753,626	30,306,351	36,859,075
Unrecovered Investment -- Book	13,571,615	56,358,358	105,927,974	154,545,388	154,545,388	154,545,388	154,545,388	154,545,388	154,545,388
Book Depreciation	-	-	-	4,095,453	6,552,724	6,552,724	6,552,724	6,552,724	6,552,724
Unrecovered Investment -- Tax total	13,571,615	56,358,358	105,927,974	154,545,388	154,545,388	154,545,388	154,545;388	154,545,388	154,545,388
Tax Depreciation	-	-	-	5,795,452	11,156,632	10,318,996	9,546,269	8,829,178	8,167,724
Allowed Rate of Return	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%
Book Depreciation expense total	-	-	-	4,095,453	6,552,724	6,552,724	6,552,724	6,552,724	6,552,724
Tax Depreciation expense total	-	-	-	5,795,452	11,156,632	10,318,996	9,546,269	8,829,178	8,167,724
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	-	-	-	607,070	1,644,055	1,344,935	1,068,995	812,922	576,716
Revenue Recovery on Capital Expenditure to date									
Eligible Plant, cumulative capital expenditures	13,571,615	56,358,358	105,927,974	154,545,388	154,545,388	154,545,388	154,545,388	154,545,388	154,545,388
Less. Retired Plant	-	-	-	(2,532,868)	(2,532,868)	(2,532,868)	(2,532,868)	(2,532,868)	(2,532,868)
Less: Accumulated Depreciation	-	-	-	(4,095,453)	(10,648,177)	(17,200,902)	(23,753,626)	(30,306,351)	(36,859,075)
Plus: Accumulated Depreciation on Retired Plant	-	-	-	2,410,292	2,410,292	2,410,292	2,410,292	2,410,292	2,410,292
Less: Deferred Tax Balance	-	-	-	(607,070)	(2,251,125)	(3,596,060)	(4,665,055)	(5,477,977)	(6,054,693)
Plus: Deferred Tax Balance on Retired Plant	-	-	-	19,604	19,604	19,604	19,604	19,604	19,604
Environmental Compliance Rate Base	13,571,615	56,358,358	105,927,974	149,739,893	141,543,114	133,645,454	126,023,735	118,658,089	111,528,648
Rate of return	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%
Return on Environmental Compliance Rate Base	$ 1,535,323	$ 6,375,682	$ 11,983,370	$ 16,939,704	$ 16,012,423	$ 15,118,980	$ 14,256,754	$ 13,423,496	$ 12,616,960
Operating Expenses	-	-	-	5,298,902	9,156,028	9,339,149	9,525,932	9,716,451	9,910,780
Annual Depreciation expense	-	-	-	4,095,453	6,552,724	6,552,724	6,552,724	6,552,724	6,552,724
Less depreciation on retired plant	-	-	-	(8,949)	(8,949)	(8,949)	(8,949)	(8,949)	(8,949)
Annual Property Tax expense	-	20,357	84,538	158,892	225,675	215,846	206,017	196,188	186,359
Total OE	$ -	$ 20,357	$ 84,538	$ 9,544,297	$ 15,925,478	$ 16,098,770	$ 16,275,724	$ 16,456,413	$ 16,640,913
Total E(m) - Project	1,535,323	6,396,039	12,067,907	26,484,001	31,937,901	31,217,750	30,532,477	29,879,910	29,257,873

Revenue Requirements Project Detail
2011 Amended Plan - LG&E Project 26

	2012	2013	2014	April 2015	2016	2017	2018	2019	2020
In-Service				1	2	3	4	5	6
Mill Creek 2NPC									
CapEx - MC2 PM Control System - SAM Mitigation	$ 12,967,870	$ 41,386,870	$ 49,120,072	$ 47,612,217	$ -	$ -	$ -	$ -	$ -
Accumulated Expenditures	$ 12,967,870	$ 54,354,740	$ 103,474,812	$ 151,087,029	$ 151,087,029	$ 151,087,029	$ 151,087,029	$ 151,087,029	$ 151,087,029
Book Depreciation rate, per year	0.000%	0.000%	0.000%	4.700%	4.700%	4.700%	4.700%	4.700%	4.700%
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	-	-	-	227,053	1,586,134	2,652,788	3,449,676	3,996,222	4,311,848
Book Accumulated Depreciation Balance	-	-	-	5,029,939	12,131,029	19,232,120	26,333,210	33,434,301	40,535,391
Unrecovered Investment -- Book	12,967,870	54,354,740	103,474,812	151,087,029	151,087,029	151,087,029	151,087,029	151,087,029	151,087,029
Book Depreciation	-	-	-	5,029,939	7,101,090	7,101,090	7,101,090	7,101,090	7,101,090
Unrecovered Investment -- Tax total	12,967,870	54,354,740	103,474,812	151,087,029	151,087,029	151,087,029	151,087,029	151,087,029	151,087,029
Tax Depreciation	-	-	-	5,665,764	10,906,973	10,088,081	9,332,646	8,631,602	7,984,949
Allowed Rate of Return	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%
Book Depreciation expense total	-	-	-	5,029,939	7,101,090	7,101,090	7,101,090	7,101,090	7,101,090
Tax Depreciation expense total	-	-	-	5,665,764	10,906,973	10,088,081	9,332,646	8,631,602	7,984,949
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	-	-	-	227,053	1,359,081	1,066,654	796,888	546,546	315,626
Revenue Recovery on Capital Expenditure to date									
Eligible Plant, cumulative capital expenditures	12,967,870	54,354,740	103,474,812	151,087,029	151,087,029	151,087,029	151,087,029	151,087,029	151,087,029
Less: Retired Plant	-	-	-	(625,711)	(625,711)	(625,711)	(625,711)	(625,711)	(625,711)
Less: Accumulated Depreciation	-	-	-	(5,029,939)	(12,131,029)	(19,232,120)	(26,333,210)	(33,434,301)	(40,535,391)
Plus: Accumulated Depreciation on Retired Plant	-	-	-	550,727	550,727	550,727	550,727	550,727	550,727
Less: Deferred Tax Balance	-	-	-	(227,053)	(1,586,134)	(2,652,788)	(3,449,676)	(3,996,222)	(4,311,848)
Plus: Deferred Tax Balance on Retired Plant	-	-	-	29,169	29,169	29,169	29,169	29,169	29,169
Environmental Compliance Rate Base	12,967,870	54,354,740	103,474,812	145,784,222	137,324,051	129,156,306	121,258,327	113,610,691	106,193,975
Rate of return	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%
Return on Environmental Compliance Rate Base	$ 1,467,023	$ 6,149,017	$ 11,705,850	$ 16,492,209	$ 15,535,131	$ 14,611,134	$ 13,717,655	$ 12,852,497	$ 12,013,462
Operating Expenses	-	-	-	6,437,195	9,640,391	9,833,199	10,029,863	10,230,460	10,435,069
Annual Depreciation expense	-	-	-	5,029,939	7,101,090	7,101,090	7,101,090	7,101,090	7,101,090
Less depreciation on retired plant	-	-	-	(2,451)	(2,451)	(2,451)	(2,451)	(2,451)	(2,451)
Annual Property Tax expense	-	19,452	81,532	155,212	219,086	208,434	197,782	187,131	176,479
Total OE	$ -	$ 19,452	$ 81,532	$ 11,619,895	$ 16,958,116	$ 17,140,272	$ 17,326,285	$ 17,516,230	$ 17,710,188
Total E(m) - Project	1,467,023	6,168,469	11,787,382	28,112,104	32,493,247	31,751,406	31,043,940	30,368,727	29,723,650

Revenue Requirements Project Detail
2011 Amended Plan - LG&E Project 26

	2012	2013	2014	October 2015	2016	2017	2018	2019	2020
In-Service				1	2	3	4	5	6
Mill Creek 3NPC									
CapEx - MC3 PM Control System - SAM Mitigation - SCR Turn-down	$ 4,615,765	$ 45,032,370	$ 49,061,558	$ 43,768,430	$ 7,545,814	$ -	$ -	$ -	$ -
Accumulated Expenditures	$ 4,808,137	$ 49,840,507	$ 98,902,065	$ 142,670,495	$ 150,216,309	$ 150,216,309	$ 150,216,309	$ 150,216,309	$ 150,216,309
Book Depreciation rate, per year	0.000%	0.000%	0.000%	3.870%	3.870%	3.870%	3.870%	3.870%	3.870%
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	-	-	-	1,499,771	3,296,250	4,801,988	6,039,514	7,028,141	7,787,178
Book Accumulated Depreciation Balance	-	-	-	1,150,281	6,963,652	12,777,023	18,590,394	24,403,766	30,217,137
Unrecovered Investment -- Book	4,808,137	49,840,507	98,902,065	142,670,495	150,216,309	150,216,309	150,216,309	150,216,309	150,216,309
Book Depreciation	-	-	-	1,150,281	5,813,371	5,813,371	5,813,371	5,813,371	5,813,371
Unrecovered Investment -- Tax total	4,808,137	49,840,507	98,902,065	142,670,495	150,216,309	150,216,309	150,216,309	150,216,309	150,216,309
Tax Depreciation	-	-	-	5,350,144	10,844,115	10,029,943	9,278,861	8,581,858	7,938,932
Allowed Rate of Return	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%
Book Depreciation expense total	-	-	-	1,150,281	5,813,371	5,813,371	5,813,371	5,813,371	5,813,371
Tax Depreciation expense total	-	-	-	5,350,144	10,844,115	10,029,943	9,278,861	8,581,858	7,938,932
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	-	-	-	1,499,771	1,796,479	1,505,738	1,237,527	988,627	759,038
Revenue Recovery on Capital Expenditure to date									
Eligible Plant, cumulative capital expenditures	4,808,137	49,840,507	98,902,065	142,670,495	150,216,309	150,216,309	150,216,309	150,216,309	150,216,309
Less. Retired Plant	-	-	-	(10,458,472)	(10,458,472)	(10,458,472)	(10,458,472)	(10,458,472)	(10,458,472)
Less: Accumulated Depreciation	-	-	-	(1,150,281)	(6,963,652)	(12,777,023)	(18,590,394)	(24,403,766)	(30,217,137)
Plus: Accumulated Depreciation on Retired Plant	-	-	-	3,546,670	3,546,670	3,546,670	3,546,670	3,546,670	3,546,670
Less: Deferred Tax Balance	-	-	-	(1,499,771)	(3,296,250)	(4,801,988)	(6,039,514)	(7,028,141)	(7,787,178)
Plus: Deferred Tax Balance on Retired Plant	-	-	-	33,729	33,729	33,729	33,729	33,729	33,729
Environmental Compliance Rate Base	4,808,137	49,840,507	98,902,065	133,142,370	133,078,334	125,759,225	118,708,327	111,906,330	105,333,921
Rate of return	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%
Return on Environmental Compliance Rate Base	$ 543,933	$ 5,638,333	$ 11,188,546	$ 15,062,067	$ 15,054,823	$ 14,226,830	$ 13,429,180	$ 12,659,687	$ 11,916,166
Operating Expenses	-	1,693,407	3,454,550	4,645,582	12,749,152	13,004,135	13,264,218	13,529,502	13,800,092
Annual Depreciation expense	-	-	-	1,150,281	5,813,371	5,813,371	5,813,371	5,813,371	5,813,371
Less depreciation on retired plant	-	-	-	(796,706)	(796,706)	(796,706)	(796,706)	(796,706)	(796,706)
Annual Property Tax expense	289	7,212	74,761	148,353	212,280	214,879	206,159	197,439	188,719
Total OE	$ 289	$ 1,700,619	$ 3,529,311	$ 5,147,511	$ 17,978,098	$ 18,235,680	$ 18,487,043	$ 18,743,607	$ 19,005,477
Total E(m) - Project	544,221	7,338,953	14,717,857	20,209,578	33,032,921	32,462,510	31,916,222	31,403,293	30,921,643

Revenue Requirements Project Detail
2011 Amended Plan - LG&E Project 26

	2012	2013	November 2014	2015	2016	2017	2018	2019	2020
In-Service			1	2	3	4	5	6	7
Mill Creek 4NPC									
CapEx - MC4 PM Control System - SAM Mitigation - SCR Turn-down	$ 54,419,721	$ 58,845,099	$ 39,657,052	$ 9,115,060	$ -	$ -	$ -	$ -	$ -
Accumulated Expenditures	$ 59,796,566	$ 118,641,665	$ 158,298,717	$ 167,413,776	$ 167,413,776	$ 167,413,776	$ 167,413,776	$ 167,413,776	$ 167,413,776
Book Depreciation rate, per year	0.000%	0.000%	3.850%	3.850%	3.850%	3.850%	3.850%	3.850%	3.850%
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	-	-	1,847,774	3,861,879	5,551,958	6,943,119	8,056,885	8,914,777	9,535,329
Book Accumulated Depreciation Balance	-	-	761,813	7,207,243	13,652,673	20,098,104	26,543,534	32,988,964	39,434,395
Unrecovered Investment -- Book	59,796,566	118,641,665	158,298,717	167,413,776	167,413,776	167,413,776	167,413,776	167,413,776	167,413,776
Book Depreciation	-	-	761,813	6,445,430	6,445,430	6,445,430	6,445,430	6,445,430	6,445,430
Unrecovered Investment -- Tax total	59,796,566	118,641,665	158,298,717	167,413,776	167,413,776	167,413,776	167,413,776	167,413,776	167,413,776
Tax Depreciation	-	-	5,936,202	12,085,601	11,178,218	10,341,149	9,564,349	8,847,818	8,183,185
Allowed Rate of Return	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%
Book Depreciation expense total	-	-	761,813	6,445,430	6,445,430	6,445,430	6,445,430	6,445,430	6,445,430
Tax Depreciation expense total	-	-	5,936,202	12,085,601	11,178,218	10,341,149	9,564,349	8,847,818	8,183,185
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	-	-	1,847,774	2,014,105	1,690,078	1,391,161	1,113,766	857,893	620,552
Revenue Recovery on Capital Expenditure to date									
Eligible Plant, cumulative capital expenditures	59,796,566	118,641,665	158,298,717	167,413,776	167,413,776	167,413,776	167,413,776	167,413,776	167,413,776
Less: Retired Plant	-	-	-	-	-	-	-	-	-
Less: Accumulated Depreciation	-	-	(761,813)	(7,207,243)	(13,652,673)	(20,098,104)	(26,543,534)	(32,988,964)	(39,434,395)
Plus: Accumulated Depreciation on Retired Plant	-	-	-	-	-	-	-	-	-
Less: Deferred Tax Balance	-	-	(1,847,774)	(3,861,879)	(5,551,958)	(6,943,119)	(8,056,885)	(8,914,777)	(9,535,329)
Plus: Deferred Tax Balance on Retired Plant	-	-	-	-	-	-	-	-	-
Environmental Compliance Rate Base	59,796,566	118,641,665	155,689,130	156,344,654	148,209,145	140,372,554	132,813,358	125,510,035	118,444,052
Rate of return	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%
Return on Environmental Compliance Rate Base	$ 6,764,638	$ 13,421,638	$ 17,612,727	$ 17,686,884	$ 16,766,534	$ 15,880,000	$ 15,024,847	$ 14,198,640	$ 13,399,283
Operating Expenses	-	-	3,611,316	15,160,250	15,463,455	15,772,725	16,088,179	16,409,943	16,738,141
Annual Depreciation expense	-	-	761,813	6,445,430	6,445,430	6,445,430	6,445,430	6,445,430	6,445,430
Less depreciation on retired plant	-	-	-	-	-	-	-	-	-
Annual Property Tax expense	8,065	89,695	177,962	236,305	240,310	230,642	220,974	211,305	201,637
Total OE	$ 8,065	$ 89,695	$ 4,551,091	$ 21,841,986	$ 22,149,196	$ 22,448,797	$ 22,754,583	$ 23,066,678	$ 23,385,209
Total E(m) - Project	6,772,703	13,511,333	22,163,818	39,528,871	38,915,730	38,328,797	37,779,430	37,265,318	36,784,492

Revenue Requirements Project Detail
2011 Amended Plan - LG&E Project 27

	2012	2013	2014	November 2015	2016	2017	2018	2019	2020
In-Service				1	2	3	4	5	6
TrimblePC									
Capital Expenditures - TC1 PM Control Systems	$ -	$ 23,479,869	$ 37,849,548	$ 57,140,608	$ 5,282,332	$ -	$ -	$ -	$ -
Accumulated Expenditures	$ -	$ 23,479,869	$ 61,329,417	$ 118,470,025	$ 123,752,357	$ 123,752,357	$ 123,752,357	$ 123,752,357	$ 123,752,357
Book Depreciation rate, per year	0.000%	0.000%	0.000%	3.620%	3.620%	3.620%	3.620%	3.620%	3.620%
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	-	-	-	1,395,029	2,985,498	4,336,446	5,466,435	6,391,372	7,127,169
Book Accumulated Depreciation Balance	-	-	-	536,077	5,015,912	9,495,748	13,975,583	18,455,418	22,935,254
Unrecovered Investment -- Book	-	23,479,869	61,329,417	118,470,025	123,752,357	123,752,357	123,752,357	123,752,357	123,752,357
Book Depreciation	-	-	-	536,077	4,479,835	4,479,835	4,479,835	4,479,835	4,479,835
Unrecovered Investment -- Tax total	-	23,479,869	61,329,417	118,470,025	123,752,357	123,752,357	123,752,357	123,752,357	123,752,357
Tax Depreciation	-	-	-	4,442,626	8,933,683	8,262,945	7,644,183	7,069,972	6,540,312
Allowed Rate of Return	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%
Book Depreciation expense total	-	-	-	536,077	4,479,835	4,479,835	4,479,835	4,479,835	4,479,835
Tax Depreciation expense total	-	-	-	4,442,626	8,933,683	8,262,945	7,644,183	7,069,972	6,540,312
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	-	-	-	1,395,029	1,590,469	1,350,948	1,129,989	924,938	735,796
Revenue Recovery on Capital Expenditure to date									
Eligible Plant, cumulative capital expenditures	-	23,479,869	61,329,417	118,470,025	123,752,357	123,752,357	123,752,357	123,752,357	123,752,357
Less: Retired Plant	-	-	-	-	-	-	-	-	-
Less: Accumulated Depreciation	-	-	-	(536,077)	(5,015,912)	(9,495,748)	(13,975,583)	(18,455,418)	(22,935,254)
Plus: Accumulated Depreciation on Retired Plant	-	-	-	-	-	-	-	-	-
Less: Deferred Tax Balance	-	-	-	(1,395,029)	(2,985,498)	(4,336,446)	(5,466,435)	(6,391,372)	(7,127,169)
Plus: Deferred Tax Balance on Retired Plant	-	-	-	-	-	-	-	-	-
Environmental Compliance Rate Base	-	23,479,869	61,329,417	116,538,920	115,750,947	109,920,164	104,310,340	98,905,567	93,689,935
Rate of return	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%	11.31%
	$ -	$ 2,656,220	$ 6,938,045	$ 13,183,760	$ 13,094,619	$ 12,434,997	$ 11,800,371	$ 11,188,942	$ 10,598,911
Operating Expenses	-	-	-	3,732,365	7,614,024	7,766,305	7,921,631	8,080,064	8,241,665
Annual Depreciation expense	-	-	-	536,077	4,479,835	4,479,835	4,479,835	4,479,835	4,479,835
Less depreciation on retired plant	-	-	-	-	-	-	-	-	-
Annual Property Tax expense	-	-	35,220	91,994	176,901	178,105	171,385	164,665	157,945
Total OE	$ -	$ -	$ 35,220	$ 4,360,436	$ 12,270,761	$ 12,424,245	$ 12,572,851	$ 12,724,564	$ 12,879,446
Total E(m) - Project	-	2,656,220	6,973,265	17,544,196	25,365,379	24,859,241	24,373,222	23,913,506	23,478,356